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

FORM 8-K

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

Date of Report (Date of earliest event reported) April 29, 2013

MAGELLAN MIDSTREAM PARTNERS, L.P.
(Exact Name of Registrant as Specified in Charter)

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

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

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

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

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

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

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

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

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

Item 8.01. Other Events.

The terms “we”, “us”, “our” and similar language included in this Current Report on Form 8-K refers to Magellan Midstream Partners, L.P., together with its subsidiaries.

As previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2012 filed with the Securities and Exchange Commission ("SEC") on February 22, 2013 ("2012 10-K"), we have changed our reporting segments effective January 1, 2013. We have undertaken a number of strategic changes in our businesses, particularly in the area of our crude oil activities, which have had or will have a significant impact on the way we manage our operations. Because of these changes, and in order to achieve certain other operational efficiencies, we have modified our organizational structure. Accordingly, effective January 1, 2013, we redesigned our internal management reports to correspond to this new organizational structure, resulting in changes to our reporting segments. Our new reporting segments are as follows:

- Refined products,
- Crude oil, and
- Marine storage.

A summary of each of our current reporting segments follows:

- The refined products segment includes the financial results from most of our previous petroleum pipeline system segment as well as results from the independent terminals (formerly referred to as Inland terminals) and our former ammonia pipeline system segment.

- The crude oil segment includes the financial results for: (i) the Longhorn crude oil pipeline, which will transport crude oil from West Texas to Houston, Texas; (ii) the Cushing, Oklahoma pipeline and terminal; (iii) the Houston area crude 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 equity earnings of Osage Pipe Line Company, LLC, Double Eagle Pipeline LLC (“Double Eagle”) and BridgeTex Pipeline Company, LLC (“BridgeTex”). The Longhorn pipeline is expected to be operational in early 2013 with full capacity reached in the second half of the year. The Double Eagle pipeline will transport condensate from the Eagle Ford shale in South Texas to our terminal in Corpus Christi, Texas and is expected to be fully operational by the second half of 2013. The BridgeTex pipeline will transport crude oil from West Texas for delivery to refineries in the Houston Gulf Coast area. The BridgeTex pipeline is currently under construction and is expected to be operational in mid-2014.

- The marine storage segment includes the financial results from our five marine terminals included in our former petroleum terminals segment and the equity earnings from Texas Frontera, LLC.

Exhibit 99.1 hereto updates the following information contained in our 2012 10-K to reflect these changes in reportable segments: (i) Item 1. Business; (ii) Item 6. Selected Financial Data; (iii) Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A"); and (iv) Item 8. Financial Statements and Supplementary Data. All other information in the 2012 10-K has not been updated for events or developments that occurred with respect to our businesses subsequent to the filing of the 2012 10-K with the SEC. The information in this Form 8-K, including the exhibits, should be read in conjunction with the 2012 10-K and subsequent SEC filings.

The revised MD&A and consolidated financial statements continue to speak as of the date of the filing our our 2012 10-K report with the SEC and have not been updated for events or developments that occurred subsequent to such filing.

Item 9.01. Financial Statements and Exhibits.

Exhibit 23.1	Consent of Independent Registered Public Accounting Firm
Exhibit 99.1	Item 1—Business, Item 6—Selected Financial Data, Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8—Financial Statements and Supplementary Data from our 2012 10-K for the year ended December 31, 2012, updated to reflect revised operating segment information.
Exhibit 101.INS	XBRL Instance Document
Exhibit 101.SCH	XBRL Taxonomy Extension Schema
Exhibit 101.CAL	XBRL Taxonomy Extension Calculations 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

SIGNATURES

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

Magellan Midstream Partners, L.P.

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

Date: April 29, 2013

By: /s/ John D. Chandler
Name: John D. Chandler
Title: Senior Vice President
and Chief Financial Officer

EXHIBIT INDEX

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Exhibit 23

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

1) Registration Statement (Form S-3 No. 333-183013) of Magellan Midstream Partners, L.P.;

2) Registration Statement (Form S-8 No. 333-71670) pertaining to the Magellan Midstream Partners Long-Term Incentive Plan of Magellan Midstream Partners, L.P., as amended by Post-Effective Amendment No. 1;

3) Registration Statement (Form S-8 No. 333-147206) pertaining to the Magellan Midstream Partners Long-Term Incentive Plan of Magellan Midstream Partners, L.P.; and

4) Registration Statement (Form S-8 No. 333-176062) pertaining to the Magellan Midstream Partners Long-Term Incentive Plan of Magellan Midstream Partners, L.P.;

of our reports dated February 22, 2013 (April 29, 2013 as to the matters discussed in Notes 1, 2, 4, 8, 15 and 21), with respect to the consolidated financial statements of Magellan Midstream Partners, L.P. and the effectiveness of internal control over financial reporting of Magellan Midstream Partners, L.P. included in this Current Report (Form 8-K) dated April 29, 2013.

/s/ Ernst & Young LLP

Tulsa, Oklahoma

April 29, 2013

Exhibit 99.1

MAGELLAN MIDSTREAM PARTNERS, L.P.

ITEM 1.

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.

Two-for-One Unit Split

In October 2012, we completed a two-for-one split of our limited partner units. Holders of record on September 28, 2012 received one additional limited partner unit at the close of business on October 12, 2012 for each unit owned on the record date. All unit and per unit amounts in this report have been retrospectively restated for this split.

BridgeTex Joint Venture

In November 2012, we formed BridgeTex Pipeline Company, LLC ("BridgeTex"), a joint venture with an affiliate 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 crude oil storage. We expect to spend approximately $600 million 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.

(b) Financial Information About Segments

See Part II—Item 8. Financial Statements and Supplementary Data in this Exhibit 99.1.

(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, 2012, our asset portfolio consisted of:

- our refined products segment, including our 8,800-mile refined products pipeline system with 49 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 800 miles of crude oil pipelines and storage facilities with an aggregate storage capacity of approximately 15 million barrels; and

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

Products transported, stored and distributed through our pipelines and terminals include:

- *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 and oxygenates;

- *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.

Industry Background

The U.S. refined products transportation and distribution system links oil refineries to end-users of gasoline and other petroleum products. This system is comprised of a network of pipelines, terminals, storage facilities, tankers, waterborne vessels, railcars and trucks. For transportation of refined products, pipelines are generally the lowest-cost alternative for intermediate and long-haul movements between different markets. Throughout the distribution system, terminals play a key role in moving products to the end-user markets by providing storage, distribution, blending and other ancillary services.

The Gulf Coast region is a significant refined products supply source for our facilities and is a major hub for petroleum refining. According to the “Annual Refinery Report for 2012” published by the Energy Information Administration (“EIA”), the Gulf Coast region accounted for approximately 46% of total U.S. daily refining capacity.

The crude oil available to U.S. and world-wide refineries consists of a substantial number of different grades and varieties. This is due to crude oil from different producing regions, whether from within or outside the U.S., that may have unique qualities, each with varying economic attributes. Consequently, different refineries have developed a distinct configuration of process units designed to handle particular grades of crude oil. This creates transportation, terminalling and storage challenges associated with regional volumetric supply and demand imbalances. In many cases, these factors result in the need for certain grades to be batched or segregated in the transportation and storage processes or blended to precise specifications. One of the largest storage hubs for crude oil is in Cushing, Oklahoma, the delivery point for crude oil futures contracts traded on the New York Mercantile Exchange ("NYMEX"). From Cushing, the crude oil is shipped to various refineries throughout the U.S. With higher crude oil prices and improved drilling technology, new domestic fields are being developed and previously existing fields are being redeveloped, increasing the need for new or expanded transportation and storage infrastructure.

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 8,800 miles from the Gulf Coast refining region across Texas and through the Midwest to Colorado, North Dakota, Minnesota, Wisconsin and Illinois. The system includes approximately 38 million barrels of aggregate usable storage capacity at 49 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 revenues, operating margin and total assets:

	Year Ended December 31,		
	2010	2011	2012
Percent of consolidated revenues	89%	87%	86%
Percent of consolidated operating margin	80%	77%	75%
Percent of consolidated total assets	72%	68%	57%

See Note 15—*Segment Disclosures* in the accompanying consolidated financial statements for additional financial information about our refined products segment.

Operations. During 2012, 66% of the refined products segment's revenues (excluding product sales revenues) were 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 33 of our pipeline system's 49 connected terminals. Revenues from terminalling and storage at the other 16 terminals on our refined products pipeline system are at privately negotiated rates.

In 2012, the products transported on our refined products pipeline system were comprised of 57% gasoline, 35% distillates and 8% aviation fuel and LPGs. The operating statistics below reflect our pipeline system's operations for the periods indicated:

	Year Ended December 31,		
	2010	**2011**	**2012**
Shipments (thousand barrels):			
Refined products:			
Gasoline	194,338	208,852	223,692
Distillates	122,929	136,003	136,709
Aviation fuel	22,612	25,245	21,557
LPGs	4,949	4,927	8,475
Total shipments	344,828	375,027	390,433

Our refined products pipeline system generated additional revenues 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 revenues 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 revenues 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 shipper's inventory a prescribed quantity of the products our shippers transport on our pipeline to compensate us for 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.

Product sales revenues in our refined products segment primarily result 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 involves purchasing LPGs and blending them 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 lock in most of the margin from this blending activity by entering into either forward physical or NYMEX gasoline futures contracts at the time we purchase the related LPGs. These blending activities accounted for approximately 83% of the total product margin for the refined products segment during 2012. If the differential between the cost of LPGs (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. We purchase transmix from third parties and sell the resulting separated refined products. Prior to beginning the conversion of a portion of our system from refined products service to crude oil service in 2012, we also purchased refined products for shipment on the Houston-to-El Paso pipeline segment to facilitate product shipments on the pipeline, and we sold those products in the El Paso, Texas wholesale market.

Product margin from commodity-related activities in our refined products segment was $92.0 million, $144.6 million and $136.7 million for the years ended December 31, 2010, 2011 and 2012, 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 revenues less product purchases, 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 15—*Segment Disclosures* to the consolidated financial statements included in Item 8 of this Exhibit 99.1.

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 as these activities could expose us to significant losses. 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. 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.

Markets and Competition. Refined products and LPG 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 44% 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 2013 projections provided by the EIA, 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 2012, approximately 68% of the products transported on our refined products pipeline system originated from 13 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 13 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	Pine Bend, MN
HollyFrontier	El Dorado, KS
HollyFrontier	Tulsa, OK
Marathon	Texas City, TX
National Cooperative Refining Association	McPherson, KS
Phillips 66	Ponca City, OK
St. Paul Park Refining	St. Paul, MN
Valero	Ardmore, OK
Valero	Houston, TX
Valero	Texas City, TX

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	Big Springs, TX 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	Borger, TX refinery
Shell	East Houston, TX	Deer Park, TX refinery
West Shore	Chicago, IL	Various Chicago, IL area refineries

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 line 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 revenues for these services that to date have been more than sufficient to offset any reduction in transportation revenues 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 2012, approximately 53% of the shipments on our pipeline system were subject to these agreements. The average remaining life of these contracts was approximately four years as of December 31, 2012, with remaining terms of up to 13 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, 2012, our refined products pipeline system had approximately 60 transportation customers. The top 10 shippers included independent refining companies, integrated oil companies and farm cooperatives. Revenues attributable to these top 10 shippers for the year ended December 31, 2012 represented 46% of total revenues for our refined products segment and 63% of revenues 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 800 miles of crude oil pipelines and approximately 13 million barrels of usable crude oil 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) our interests in Osage Pipe Line Company, LLC ("Osage"), Double Eagle Pipeline LLC ("Double Eagle") and BridgeTex.

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

	Year Ended December 31,		
	2010	**2011**	**2012**
Percent of consolidated revenues	1%	4%	5%
Percent of consolidated operating margin	5%	10%	12%
Percent of consolidated total assets	11%	11%	20%

See Note 15–*Segment Disclosures* in the accompanying consolidated financial statements in Item 8 of this Exhibit 99.1 for additional financial information about our crude oil segment.

Operations. Our crude oil assets are strategically located to serve crude oil supply, trading or demand centers. Revenues are 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 revenues 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 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 Longhorn crude oil pipeline will begin transporting crude oil from the Permian Basin in West Texas to Houston, Texas in early 2013 when we complete the project to reverse a portion of our Houston-to-El Paso pipeline segment, which had previously transported refined products, and to convert it to crude oil service. During the second half of 2013, the capacity of the pipeline will be increased from its start-up capacity of 75,000 to 225,000 barrels per day. 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.

Our East Houston terminal currently includes approximately two million barrels of usable storage capacity dedicated to crude oil service. The Longhorn pipeline will deliver crude oil to our East Houston terminal, as will the BridgeTex pipeline, when they are completed. 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. All of the current crude oil storage at our East Houston terminal is contracted to customers. 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 50 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 the reversal of the Longhorn pipeline and the 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; however, two million barrels of that storage space is 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 more than 200 miles of pipeline in Kansas and Oklahoma that are contracted to third parties for crude oil service. We earn revenues from these pipeline segments for capacity reserved even if not used by the customer.

The condensate components of our Corpus Christi, Texas terminal currently consist of approximately one million barrels of usable storage capacity. 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.

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 Double Eagle, a joint venture with Copano Energy, L.L.C. ("Copano"), that is constructing a 140-mile pipeline that will transport condensate from the Eagle Ford shale formation in SouthTexas to our terminal in Corpus Christi. The Double Eagle pipeline is expected to commence operations in early 2013 and is expected to be fully operational by the second half of 2013, at which time it will be capable of transporting approximately 100,000 barrels of condensate per day. An affiliate of Copano 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 2.6 million barrels of operational crude oil storage at Colorado City and East Houston combined and a 50-mile pipeline between East Houston and Texas City. We expect to spend approximately $600 million 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 will deliver Permian Basin production to trading and demand centers in the Houston area, and consequently will depend 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 crude oil by Gulf Coast refineries and the relative price for crude oil on the Gulf Coast 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 will compete with alternative outlets for Permian Basin production, including pipelines that transport crude oil to the Cushing crude oil trading hub as well as other pipelines that currently transport or new pipelines that may transport Permian Basin crude to the Gulf Coast. To a limited extent, the Longhorn pipeline may also compete with truck or rail alternatives for Permian Basin barrels. Indirectly, the Longhorn pipeline also may compete 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 to some extent 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 will depend on condensate production from the Eagle Ford shale formation for its supply and will compete 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 small 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. We have secured long-term agreements to support the expansion of our crude oil pipeline assets, including our Houston-area crude oil distribution system, Longhorn pipeline, Double Eagle pipeline and BridgeTex pipeline. As of December 31, 2012, 95% of our crude oil storage capacity is 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.

MARINE STORAGE

We own and operate five marine storage terminals located along coastal waterways with approximately 25 million barrels of aggregate storage capacity with an additional 0.8 million barrels of storage jointly owned through our Texas Frontera, LLC joint venture ("Texas Frontera"). Our marine terminals provide distribution, storage, blending, inventory management and additive injection services for refiners and other large end users of petroleum products. Our marine storage segment accounted for the following percentages of our consolidated revenues, operating margin and total assets:

	Year Ended December 31,		
	2010	**2011**	**2012**
Percent of consolidated revenues	9%	9%	9%
Percent of consolidated operating margin	15%	13%	13%
Percent of consolidated total assets	17%	16%	15%

See Note 15–*Segment Disclosures* in the accompanying consolidated financial statements in Item 8 of this Exhibit 99.1 for additional financial information about our marine storage segment.

Operations. Our marine storage terminals generate revenues primarily through providing long-term storage services for a variety of customers. Refiners and chemical companies typically use our storage terminals because of 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 terminals.

Our Galena Park, Texas marine terminal is located along the Houston ship channel and represents our largest marine facility with more than 13 million barrels of usable storage capacity. This facility currently stores a mix of refined products, blendstocks and heavy oils, and we are in the process of adding crude oil capabilities to this location. We primarily 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 an additional 0.8 million barrels of storage at our Galena Park terminal. This storage is leased under an agreement with a 10-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 equity earnings, 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 and ethanol. This facility receives and distributes products by pipeline, ship, barge and truck.

Our Marrero, Louisiana marine terminal is located adjacent to 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, heating oil 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. This facility's close proximity to the Eagle Ford shale formation has provided us with opportunities such as our Double Eagle joint venture discussed in our crude oil segment description.

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 revenues. 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 increased 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 several refineries have been or are in the process of being idled. 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 2012, approximately 95% of our storage terminal capacity was utilized. As of December 31, 2012, approximately 86% 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, 2012. These contracts obligate the customer to pay for terminal capacity reserved even if not used by the customer.

GENERAL BUSINESS INFORMATION

Major Customers

The percentage of revenue derived by customers that accounted for 10% or more of consolidated total revenues is provided in the table below. No other customer accounted for more than 10% of our consolidated total revenues for 2010, 2011 or 2012. The majority of the revenues from Customers A and B resulted from sales to those customers 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. In general, accounts receivable from these customers are due within three days of sale. We believe that, in the event Customer A and B were unable or unwilling to do so, other companies would purchase from us the refined products we have for sale.

	Year Ended December 31,		
	2010	**2011**	**2012**
Customer A	11%	21%	14%
Customer B	13%	8%	7%
Total	24%	29%	21%

Tariff Regulation

Interstate 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%, but 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. In addition to rate indexing, 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 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 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 and Texas. In most instances, state commissions have not initiated investigations of the rates or practices of these pipelines in the absence of shipper complaints.

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 commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Act, the CFTC has adopted anti-market manipulation regulations that prohibit, among other things, fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to assess fines of up to $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.

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 exceed 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 $49.6 million and $48.3 million at December 31, 2011 and 2012, 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 $7.7 million and $7.9 million at December 31, 2011 and 2012, 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.

Clean Air Act. Our operations are subject to the federal Clean Air Act, as amended ("CAA"), and comparable state and local laws. The CAA requires sources of emissions to obtain construction permits or approvals for new construction and operating permits for existing operations. We believe that we currently hold or have applied for all necessary air permits.

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 Environmental Protection Agency ("EPA") is required to collect the fees if a state does not administer and enforce CAA 185. The Houston-Galveston region was initially determined to be a severe nonattainment area that did not meet its 2007 attainment deadline and, as such, would be subject to CAA 185. The Texas Commission on Environmental Quality ("TCEQ") is currently considering a "Failure to Attain Rule" to implement the requirements of CAA 185. The draft Failure to Attain Rule is anticipated to be adopted in 2013 and is expected to provide for the collection of an annual failure to attain fee for excess emissions. We have certain facilities in the Houston area that will be subject to the TCEQ's Failure to Attain Rule.

Management believes the most likely scenario is that we will be assessed fees for excess emissions at our Houston-area facilities and our estimate of the possible range of loss associated with this matter is from zero to $14.3 million. As of December 31, 2012, we have accrued $10.9 million as a long-term environmental liability related to this matter. Management believes that recent indications with regard to this matter by the TCEQ and the EPA have been favorable to us. The final Failure to Attain Rule is expected to be published in 2013; therefore, it is likely that our estimate of this loss will change in the near term.

Stationary Engine Emission Standards. The EPA has set a May 2013 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, generally anticipates the installation of catalytic converters to the engine exhaust to achieve compliance, which is the solution we are pursuing;

however, engine replacements may be required if it is determined that catalytic converters will not achieve the required level of emission reductions. We have received a one-year extension to meet the stationary engine emission standards. If we are not able to modify or replace 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.

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.

The DHS has preliminarily determined that one of our facilities storing butane meets their security risk screening threshold and is regulated under the DHS Chemical Facility Anti-Terrorism Standards ("CFATS"). We have submitted a security plan for this facility and are awaiting a response from the DHS as to whether additional security measures will be needed for this facility to be in compliance with CFATS. The DHS has continued to delay final security risk determinations for gasoline storage facilities while it addresses program implementation challenges. Management believes that our costs to comply with CFATS will not be material to our operating results, financial position or cash flows.

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 because 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. The Oil Pollution Act amended provisions of the Federal Water Pollution Control Act of 1972, as amended ("Water Pollution Control Act"), and other statutes as they pertain to prevention and response to crude oil and refined product spills. The Oil Pollution Act subjects owners of facilities to strict, joint and potentially significant liability for removal costs and certain other consequences of an oil 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 an oil 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 Water Pollution Control Act 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 Water Pollution Control Act 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 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.

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.

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 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 effect on our results of operations.

Title to Properties

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

Some of the leases, easements, rights-of-way, permits and licenses that have been transferred to us are only transferable with the consent of the grantor of these rights, which in some instances is a governmental entity. We believe that we have obtained or will obtain sufficient third-party consents, permits and authorizations 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 or are entitled to indemnification from former affiliates for title defects to our ammonia pipeline and certain marine terminal assets that arise before February 2016. 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, 2012, we had 1,339 employees. At December 31, 2012, the labor force of 768 employees assigned to our refined products segment was concentrated in the central U.S. Approximately 29% 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, 2012, the labor force of 26 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 175 employees assigned to our marine storage segment at December 31, 2012 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, 2013.

(d) Financial Information About Geographical Areas

We have no international activities. For all periods included in this report, all our revenues were derived from operations conducted in, and all of our assets were located in, the U.S. See Note 15–*Segment Disclosures* in the notes to consolidated financial statements in Item 8 of this Exhibit 99.1 for information regarding our revenues 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.

PART II

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 our Annual Report on Form 10-K dated December 31, 2012. 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 August 2012, our general partner's board of directors approved a two-for-one split of our limited partner units, which was completed on October 12, 2012. We have retrospectively restated all unit and per unit amounts associated with this split in this report for each respective period presented.

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. 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 adjusted EBITDA to net income, which are the nearest comparable GAAP financial measures, are included in the following tables. See Note 15–*Segment Disclosures* in the accompanying consolidated financial statements in Item 8 of this Exhibit 99.1 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 the investment community to assess the financial results of an entity.

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

	Year Ended December 31,				
	2008	2009	2010	2011	2012
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenues	$ 638,810	$ 678,945	$ 793,599	$ 893,369	$ 970,744
Product sales revenues	574,095	334,465	763,090	854,528	799,382
Affiliate management fee revenues	733	761	758	770	1,948
Total revenues	1,213,638	1,014,171	1,557,447	1,748,667	1,772,074
Operating expenses	264,871	257,635	282,212	306,415	328,454
Product purchases	436,567	280,291	668,585	706,270	657,108
Gain on assignment of supply agreement	(26,492)	—	—	—	—
Equity earnings	(4,067)	(3,431)	(5,732)	(6,763)	(2,961)
Operating margin	542,759	479,676	612,382	742,745	789,473
Depreciation and amortization expense	86,501	97,216	108,668	121,179	128,012
G&A expense	73,302	84,049	95,316	98,669	109,403
Operating profit	382,956	298,411	408,398	522,897	552,058
Interest expense, net	50,479	69,187	93,296	105,634	111,679
Debt placement fee amortization	767	1,112	1,401	1,831	2,087
Other (income) expense, net	(380)	(24)	750	—	—
Income before provision for income taxes	332,090	228,136	312,951	415,432	438,292
Provision for income taxes	1,987	1,661	1,371	1,866	2,622
Net income	$ 330,103	$ 226,475	$ 311,580	$ 413,566	$ 435,670
Net income allocation:[a]					
Non-controlling owners' interest	$ 244,430	$ 99,729	$ (397)	$ (63)	$ —
Limited partner interests	87,733	126,746	311,977	413,629	435,670
General partner interest	(2,060)	—	—	—	—
Net income	$ 330,103	$ 226,475	$ 311,580	$ 413,566	$ 435,670
Basic and diluted net income per limited partner unit	$ 1.11	$ 1.11	$ 1.42	$ 1.83	$ 1.92
Balance Sheet Data:					
Working capital (deficit)	$ (29,644)	$ 94,571	$ 109,536	$ 301,135	$ 307,658
Total assets	$ 2,600,708	$ 3,163,148	$ 3,717,900	$ 4,045,001	$ 4,420,067
Long-term debt	$ 1,083,485	$ 1,680,004	$ 1,906,148	$ 2,151,775	$ 2,393,408
Owners' equity	$ 1,254,132	$ 1,196,354	$ 1,469,571	$ 1,463,403	$ 1,515,702
Cash Distribution Data:					
Cash distributions declared per MMP unit[b]	$ 1.39	$ 1.42	$ 1.48	$ 1.59	$ 1.88
Cash distributions paid per MMP unit[b]	$ 1.36	$ 1.42	$ 1.45	$ 1.56	$ 1.78

	Year Ended December 31,				
	2008	2009	2010	2011	2012
	(in thousands, except operating statistics)				
Other Data:					
Operating margin:					
Refined products	$ 468,877	$ 388,083	$ 491,290	$ 574,030	$ 592,828
Crude oil	8,298	8,492	28,517	74,225	91,367
Marine storage	62,101	79,262	89,566	91,571	102,323
Allocated partnership depreciation costs[c]	3,483	3,839	3,009	2,919	2,955
Operating margin	$ 542,759	$ 479,676	$ 612,382	$ 742,745	$ 789,473
Distributable cash flow:					
Net income	$ 330,103	$ 226,475	$ 311,580	$ 413,566	$ 435,670
Interest expense, net	50,479	69,187	93,296	105,634	111,679
Depreciation and amortization expense[d]	87,268	98,328	110,069	123,010	130,099
Equity-based incentive compensation expense[e]	931	6,123	15,499	10,243	8,038
Asset retirements and impairments	7,180	5,529	1,062	8,599	12,622
Commodity-related adjustments[f]	(13,787)	24,262	7,751	(22,370)	12,894
Product supply agreement gains[g]	(26,919)	—	—	—	—
Other[h]	(3,331)	5,685	(1,582)	(2,504)	4,850
Adjusted EBITDA	431,924	435,589	537,675	636,178	715,852
Interest expense, net	(50,479)	(69,187)	(93,296)	(105,634)	(111,679)
Maintenance capital (net of reimbursements)	(43,232)	(37,999)	(44,620)	(70,002)	(64,396)
Distributable cash flow	$ 338,213	$ 328,403	$ 399,759	$ 460,542	$ 539,777
Operating Statistics:					
Refined products:[i]					
Transportation revenue per barrel shipped	$ 1.193	$ 1.205	$ 1.197	$ 1.175	$ 1.230
Volume shipped (million barrels):					
Gasoline	152.7	169.9	194.3	208.9	223.7
Distillates	114.8	100.2	122.9	136.0	136.7
Aviation fuel	22.2	19.9	22.6	25.3	21.5
Liquefied petroleum gases	6.2	5.7	5.0	4.9	8.5
Total volume shipped	295.9	295.7	344.8	375.1	390.4
Crude oil:[i]					
Transportation revenue per barrel shipped	$ —	$ —	$ 0.283	$ 0.275	$ 0.305
Volumes shipped (million barrels)	—	—	14.7	43.2	72.0
Crude oil terminal average utilization (million barrels per month)	1.2	1.2	3.4	9.3	12.6
Marine storage:					
Marine terminal average utilization (million barrels per month)	21.3	23.4	24.0	24.7	23.8

(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) 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.

(c) Certain assets were contributed to us and were recorded as property, plant and equipment at the partnership level. The associated depreciation expense was allocated to our various business segments, which in turn recognized these allocated costs as operating expense, reducing segment operating margins by these amounts.

(d) Includes debt placement fee amortization.

(e) Excludes the tax withholdings on settlement of these equity-based incentive awards, which were paid in cash.

(f) See *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Distributable Cash Flow* in this Exhibit 99.1 for details of these commodity-related adjustments.

(g) In October 2004, as part of our acquisition of a pipeline system, we assumed a third-party supply agreement. Because the expected profits from this supply agreement were below the fair value of the associated tariff-based shipments on the acquired pipeline, we recognized a liability for the difference. From 2004 until the first quarter of 2008, we amortized a portion of this liability to revenues. We adjusted these non-cash revenue credits out of our DCF calculations. In 2008, we assigned this supply agreement to a separate third party and recognized a non-cash gain on that transaction of $26.5 million, which we also eliminated from our DCF calculations.

(h) Other primarily includes adjustments for equity investment earnings and distributions and non-controlling owners' interests losses included in net income during 2010 and 2011. Years 2008 and 2009 also include expense paid by or credited to a former affiliate.

(i) We acquired crude oil and refined products pipelines in South Texas during September 2010. Other than our equity interest in Osage Pipe Line Company, LLC, we had no crude oil pipeline operations prior to that date. The volumes on these pipelines travel short distances, and we charge a significantly lower tariff rate on these pipelines than we do 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 refined petroleum products and crude oil. Our three operating segments include:

- refined products segment, including our 8,800-mile refined products pipeline system with 49 terminals as well as 27 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;
- crude oil segment, comprised of approximately 800 miles of crude oil pipelines and storage facilities with an aggregate storage capacity of approximately 15 million barrels; and
- marine storage segment, consisting of marine terminals located along coastal waterways with an aggregate storage capacity of approximately 26 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 revised consolidated financial statements and related notes for the year ended December 31, 2012 included in this Exhibit 99.1 on Form 8-K.

Recent Developments

BridgeTex Pipeline Company, LLC. In November 2012, we formed BridgeTex Pipeline Company, LLC ("BridgeTex"), a joint venture with an affiliate 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 approximately $600 million for 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.

Sale of Claim Against MF Global Inc. In October 2011, MF Global Holdings Ltd., the parent of MF Global Inc. ("MF Global"), filed for bankruptcy protection under Chapter 11 of the U.S. bankruptcy laws, and a trustee was appointed to oversee the liquidation of MF Global under the Securities Investor Protection Act. At that time, MF Global served as our sole clearing agent for New York Mercantile Exchange ("NYMEX") futures contracts. We transferred our existing trading positions at MF Global to a new clearing agent in November 2011. As of the date of transfer of our account, MF Global owed us $29.4 million. We subsequently received $23.6 million as partial payment of the amount owed to us. In December 2012, we sold our remaining claim of $5.8 million to a third party for $5.4 million. The buyer of the claim assumed the risk of ultimate collectability of the claim subject to the accuracy of typical representations and warranties from us related to the claim. We charged the $0.4 million loss we sustained from the sale of this receivable to operating expense.

Debt Offering. In November 2012, we issued $250.0 million of 4.20% notes due December 1, 2042 in an underwritten public offering. The notes were issued for the discounted price of 99.3% of par. We have used or intend to use the net proceeds from this offering of approximately $245.8 million, after underwriting discounts and offering expenses, for general partnership purposes, including capital expenditures and investments in interest-bearing securities or accounts.

Cash Distribution. In January 2013, the board of directors of our general partner declared a quarterly cash distribution of $0.50 per unit for the period of October 1, 2012 through December 31, 2012. This quarterly cash distribution was paid on February 14, 2013 to unitholders of record on February 6, 2013. The total distributions paid on 226.7 million limited partner units outstanding was $113.3 million.

Pipeline Acquisition. On February 22, 2013, we announced an agreement to acquire approximately 800 miles of refined products pipeline from Plains All American Pipeline, L.P. for $190 million. Subject to regulatory approvals, we expect the acquisition to close during the second quarter of 2013. We expect to fund the acquisition with cash on hand and, if necessary, with borrowings under our revolving credit facility.

Overview

Our pipelines and terminals generate the majority of our operating margin from the transportation and storage services we provide to our customers. The revenues generated from these activities are 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.

A prolonged period of high petroleum prices or a recessionary economic environment could lead to a reduction in demand and result in lower shipments on our refined products pipeline system and reduced demand for our terminal services. Fluctuations in the prices of refined products impact the amount of cash our refined products segment generates from its butane blending and fractionation activities. In addition, increased maintenance regulations, higher power costs and higher interest rates could decrease the amount of cash we generate. See Item 1A—*Risk Factors* in our Annual Report on Form 10-K for the year ended December 31, 2012, for other risk factors that could impact our results of operations, financial position and cash flows.

Refined Products. Our common carrier pipeline system is comprised of 8,800 miles of pipeline and 49 terminals that provide transportation, storage and distribution services for refined products in 14 states from Texas through the Midwest to Colorado, North Dakota, Minnesota, Wisconsin and Illinois. Through direct refinery connections and interconnections with other interstate pipelines, our refined products pipeline can access approximately 44% of the U.S. refining capacity. In 2012, the refined products segment generated 66% of its revenues, 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 revenues 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.

During 2012, in conjunction with our project to reverse and convert the Longhorn pipeline to crude oil, we discontinued refined products transportation service on our Houston-to-El Paso pipeline segment and shifted these volumes to a nearby pipeline segment which we own. The associated linefill products we held title to on the Houston-to-El Paso pipeline were either sold to third party entities or transferred to our other pipeline segments to fulfill product shortage positions on those segments. The $37.0 million decrease in the inventory balance between December 31, 2011 and 2012 was primarily attributable to these product sales and transfers. Our butane 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 refined 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 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 revenues 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 ammonia from production facilities in Texas and Oklahoma to various distribution points in the Midwest for use as an agricultural fertilizer. We generate revenues principally from volume-based fees for the transportation of ammonia on our pipelines.

Crude Oil. Our crude oil segment includes both terminals and pipeline systems. 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 from third party pipeline connections in Crane, Texas for deliveries to Houston-area refineries and pipelines. The Longhorn pipeline will begin crude oil service in early 2013;

- The crude oil storage at our East Houston, Texas terminal is approximately two million barrels and our Corpus Christi, Texas terminal includes approximately one million barrels of condensate storage;

- 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 12 million barrels of crude oil storage; however, two million barrels of that storage space is reserved for working inventory leaving 10 million barrels that we can lease. This terminal principally serves refiners, marketers and traders. We earn revenues primarily from leasing tanks as well as from throughput fees; and

- We own more than 200 miles of pipeline in Kansas and Oklahoma that are connected to third parties for crude oil service. We earn revenues from these pipeline segments for capacity reserved even if not used by the customer.

Our crude oil segment also includes ownership interests in the following:

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

- a 50% interest in Double Eagle Pipeline LLC ("Double Eagle"), which is constructing a 140-mile pipeline to connect to a 50-mile pipeline owned by a related party entity to transport condensate to our terminal at Corpus Christi, Texas. The pipeline is expected to be fully operational by the second half of 2013; 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 and Texas City refineries. This pipeline is expected to begin service in mid-2014.

Marine Storage. Our marine storage segment consists of five storage 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 25 million barrels with an additional 0.8 million barrels of storage at our Galena Park, Texas terminal that is 50% jointly owned through our Texas Frontera, LLC joint venture ("Texas Frontera"). Because the rates charged at these terminals are unregulated, the marketplace determines the prices we can charge for our services. We earn revenues through storage and ancillary fees, including product heating, blending, mixing and additive injection for refiners and other large end-users of refined products.

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 storage has provided significant opportunity for us to build tankage along our refined products pipeline and at our marine terminals, backed by long-term customer commitments; and

- demand for crude oil and condensate storage and transportation services, which has provided the opportunity for us to reverse and convert to crude oil service a significant portion of our Houston-to-El Paso pipeline segment, construct the BridgeTex pipeline and expand our storage and transportation infrastructure in the Houston and Corpus Christi areas.

We spent $198.9 million and $364.7 million on acquisitions and growth projects during 2011 and 2012, respectively. Further, we currently expect to spend approximately $700.0 million in 2013 on projects now underway, with additional spending of approximately $290.0 million in 2014 to complete these projects. 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") costs, which management does not consider when evaluating the core profitability of our operations. 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 product purchases are determined in accordance with GAAP.

Our butane blending, fractionation and other commodity-related activities generate significant revenues from the sale of refined products and the associated gains/losses from the related derivative agreements. We believe the product margin from these activities, which takes into account the related product purchases, better represents its importance to our results of operations.

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 revenues:				
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 revenues	893.4	970.7	77.3	9 %
Affiliate management fee revenues	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)%
Product purchases	706.3	657.1	49.2	7 %
Product margin [a]	148.2	142.3	(5.9)	(4)%
Equity earnings	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		
Volume 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 revenues increased by $77.3 million, resulting from:

- an increase in refined products revenues 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 revenues of $31.1 million primarily due to:

    - additional revenues 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.

- an increase in marine storage revenues of $2.7 million primarily because of 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 current period;

- an increase in crude oil expenses of $10.1 million primarily due to lower product overages 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 current period, partially offset by higher losses on various asset retirements and replacements and higher operating taxes.

Product sales revenues primarily resulted from our butane blending activities, terminal product gains and transmix fractionation. For 2011 and a portion of 2012, product sales revenues also resulted from product marketing and linefill management associated with our Houston-to-El Paso pipeline section. We utilize NYMEX contracts to hedge against changes in the price of refined 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 revenues. 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 product purchases. 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 the current year, 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–Product Sales Revenues* below for more information about our NYMEX contracts.

Equity earnings decreased $3.8 million from 2011 primarily due to an anticipated settlement of a tariff claim against Osage (see Note 16—*Commitments and Contingencies—Osage Complaint* in the Notes to Consolidated Financial Statements in Item 8 of this Exhibit 99.1 for more information regarding this claim).

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

Year Ended December 31, 2010 Compared to Year Ended December 31, 2011

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2010	2011	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Refined products	$ 631.9	$ 680.3	$ 48.4	8 %
Crude oil	22.0	61.2	39.2	178 %
Marine storage	139.7	151.9	12.2	9 %
Total transportation and terminals revenues	793.6	893.4	99.8	13 %
Affiliate management fee revenues	0.8	0.8	—	— %
Operating expenses:				
Refined products	232.6	250.8	(18.2)	(8)%
Crude oil	0.2	(4.9)	5.1	2,550 %
Marine storage	52.4	63.4	(11.0)	(21)%
Intersegment eliminations	(3.0)	(2.9)	(0.1)	(3)%
Total operating expenses	282.2	306.4	(24.2)	(9)%
Product margin:				
Product sales	763.1	854.5	91.4	12 %
Product purchases	668.6	706.3	(37.7)	(6)%
Product margin [(a)]	94.5	148.2	53.7	57 %
Equity earnings	5.7	6.8	1.1	19 %
Operating margin	612.4	742.8	130.4	21 %
Depreciation and amortization expense	108.7	121.2	(12.5)	(11)%
G&A expense	95.3	98.7	(3.4)	(4)%
Operating profit	408.4	522.9	114.5	28 %
Interest expense (net of interest income and interest capitalized)	93.3	105.6	(12.3)	(13)%
Debt placement fee amortization	1.4	1.8	(0.4)	(29)%
Other (income) expense	0.7	—	0.7	n/a
Income before provision for income taxes	313.0	415.5	102.5	33 %
Provision for income taxes	1.4	1.9	(0.5)	(36)%
Net income	$ 311.6	$ 413.6	$ 102.0	33 %
Operating Statistics				
Refined products:				
Transportation revenue per barrel shipped	$ 1.197	$ 1.175		
Volume shipped (million barrels):				
Gasoline	194.3	208.9		
Distillates	122.9	136.0		
Aviation fuel	22.6	25.3		
Liquefied petroleum gases	5.0	4.9		
Total volume shipped	344.8	375.1		
Crude oil:				
Transportation revenue per barrel shipped	$ 0.283	$ 0.275		
Volume shipped (million barrels)	14.7	43.2		
Crude oil terminal average utilization (million barrels per month)	3.4	9.3		
Marine storage:				
Marine terminal average utilization (million barrels per month)	24.0	24.7		

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

Transportation and terminals revenues increased by $99.8 million, resulting from:

- an increase in refined products revenues of $48.4 million. Revenues from the South Texas pipelines acquired in September 2010 accounted for $5.6 million of this increase. Excluding the impact of this acquisition, revenues increased $42.8 million primarily attributable to:
    - a 4% increase in the average per-barrel tariff rate, going from $1.276 to $1.321, principally reflecting the impact of the 6.9% tariff rate increase we implemented on July 1, 2011;
    - a 2% increase in transportation volumes driven primarily by higher demand for diesel fuel;
    - a 57% increase in volumes on our ammonia pipeline system. Because we were conducting hydrostatic testing on our ammonia pipeline during 2010, it was unavailable for shipments for much of that year; and
    - higher leased storage revenue primarily due to new tanks added to our system during 2010 and 2011, higher capacity lease revenues due to increased demand and increased fees for terminal throughput and ethanol blending services.
- an increase in crude oil revenues of $39.2 million, of which approximately 70% was contributed by the increase in revenues from the Cushing, Oklahoma storage assets we acquired in September 2010. Excluding the impact of this acquisition, the remaining increase in crude oil revenues was principally due to lease revenues from newly constructed tanks at Cushing, Oklahoma that were placed in service throughout 2011; and
- an increase in marine storage revenues of $12.2 million due primarily to leases of newly constructed tanks at Galena Park, Texas.

Operating expenses increased $24.2 million, resulting from:

- an increase in refined products expenses of $18.2 million, which included a $5.1 million increase in expense related to the pipeline acquisition we completed in September 2010. Excluding the impact of this acquisition, refined products pipeline expenses increased $13.1 million due to higher property taxes, increased losses from asset replacements, higher expenses recognized in 2011 related to potential air emission fees for our Houston-area terminal, higher power costs due to increased pipeline volumes and higher personnel costs;
- a decrease in crude oil expenses of $5.1 million, which included a $7.1 million decrease in expense attributable to the Cushing storage assets acquired in September 2010. Operating expenses for these storage assets decreased primarily because favorable product overages (which reduce operating expenses) more than offset other operating expenses. Excluding these acquired assets, operating expenses increased $2.0 million principally due to higher asset integrity expense and higher compensation costs; and
- an increase in marine storage expenses of $11.0 million primarily due to expenses recognized in 2011 related to potential air emission fees for our Galena Park, Texas facility and incremental costs related to product contamination issues.

Product margin increased $53.7 million primarily due to favorable unrealized gains from NYMEX contracts as a result of the timing of those agreements, and increased profits from our butane blending and fractionation activities. The increase in our butane blending profits was primarily attributable to higher average product prices, and the increase in fractionation profits was due to an increase in fractionation volumes and higher product prices.

Equity earnings increased $1.1 million primarily due to increased shipments on the Osage pipeline in which we own a 50% interest.

Depreciation and amortization expense increased $12.5 million primarily due to expansion capital projects placed into service during 2011 and acquisitions.

G&A expense increased $3.4 million primarily due to higher personnel costs in 2011 related in large part to our crude oil development operations and higher costs related to financial system upgrades.

Interest expense, net of interest income and interest capitalized, increased $12.3 million in 2011. Our average debt outstanding increased to $2.1 billion in 2011 from $1.8 billion in 2010 principally due to borrowings for expansion capital expenditures and acquisitions. The weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, was 5.4% and 5.3%, respectively, for 2010 and 2011.

Distributable Cash Flow

Distributable cash flow ("DCF") and adjusted EBITDA are non-GAAP measures. Management uses DCF to evaluate our ability to generate cash for distribution to our limited partners. Management also uses this measure as a basis for recommending to our general partner's board of directors the amount of cash distributions to be paid each period. Adjusted EBITDA is an important measure utilized by the investment community 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, 2010, 2011 and 2012 to net income, which is the nearest comparable GAAP financial measure, is as follows (in thousands):

	Year Ended December 31,		
	2010	**2011**	**2012**
Net income	$ 311,580	$ 413,566	$ 435,670
Interest expense, net	93,296	105,634	111,679
Depreciation and amortization[(1)]	110,069	123,010	130,099
Equity-based incentive compensation expense[(2)]	15,499	10,243	8,038
Asset retirements and impairments	1,062	8,599	12,622
Commodity-related adjustments:			
Derivative losses (gains) recognized in the period associated with future product transactions[(3)]	14,945	(5,909)	6,424
Derivative losses (gains) recognized in previous periods associated with product sales completed in the period[(4)]	(7,675)	(15,162)	3,649
Lower-of-cost-or-market adjustments	3	1,017	983
Houston-to-El Paso cost of sales adjustments[(5)]	478	(2,316)	1,838
Total commodity-related adjustments	7,751	(22,370)	12,894
Other	(1,582)	(2,504)	4,850
Adjusted EBITDA	537,675	636,178	715,852
Interest expense, net	(93,296)	(105,634)	(111,679)
Maintenance capital (net of reimbursements)	(44,620)	(70,002)	(64,396)
DCF	$ 399,759	$ 460,542	$ 539,777

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

(2) Because 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, 2010, 2011 and 2012 was $18.9 million, $17.6 million and $21.0 million, respectively. However, the figures above include an adjustment for minimum statutory tax withholdings we paid in 2010, 2011 and 2012 of $3.4 million, $7.4 million and $13.0 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 goods sold 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 $60.8 million between 2010 and 2011 and increased $79.2 million between 2011 and 2012. 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 was primarily due to the impact of product price changes during each period on economic hedges that do not qualify for hedge accounting treatment.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $424.7 million, $577.3 million and $645.1 million for the years ended December 31, 2010, 2011 and 2012, respectively.

- The $67.8 million increase from 2011 to 2012 was primarily attributable to:
  - a $28.9 million increase in net income, excluding the increase in 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 cash from energy commodity derivatives contracts, net of derivatives deposits 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 Section 185 of the Clean Air Act (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.

- The $152.6 million increase from 2010 to 2011 was primarily attributable to:
  - a $113.3 million increase in net income, excluding the increase in non-cash depreciation and amortization expense and equity-based incentive compensation expense;
  - a $28.8 million increase resulting from a $14.4 million increase in cash due to the elimination of restricted cash due to our purchase of a private group's investment in a Cushing, Oklahoma storage project ("MCO") during 2011 versus a decrease in cash of the same amount associated with the formation of MCO during 2010. MCO's cash on hand was unavailable to us for our partnership matters and was recorded as restricted cash on our consolidated balance sheet at December 31, 2010;
  - a $23.0 million increase resulting from a $5.8 million decrease in trade accounts receivable and other accounts receivable in 2011 versus a $17.2 million increase in trade accounts receivable and other accounts receivable in 2010. The increase during 2010 was primarily due to the acquisition of certain storage and pipeline assets in September 2010 and timing of payments from our customers;
  - an $18.9 million increase resulting from a $16.9 million increase in current and noncurrent environmental liabilities in 2011 versus a $2.0 million decrease in current and noncurrent environmental liabilities in 2010. The increase during 2011 was primarily due to accruals related to potential air emission fees and current year and historical product releases; and
  - a $12.4 million increase resulting from a $20.2 million increase in accounts payable in 2011 versus a $7.8 million increase in accounts payable in 2010 primarily due to the timing of invoices paid to vendors and suppliers.

These increases were partially offset by:

- a $23.5 million decrease resulting from a $19.8 million decrease in energy commodity derivatives contracts, net of derivatives deposits, in 2011, versus a $3.7 million increase in energy commodity derivatives contracts, net of derivatives deposits, in 2010, due to the change in commodity prices during the respective periods; and
- a $19.1 million decrease primarily resulting from the impact of higher product prices and higher levels of inventory purchases in 2011 as compared to 2010; specifically, a $42.5 million increase in inventory in 2011 versus a $23.4 million increase in inventory in 2010.

Net cash used by investing activities for the years ended December 31, 2010, 2011 and 2012 was $590.2 million, $258.7 million and $368.1 million, respectively. 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 paid $74.9 million for growth projects in conjunction with our joint venture co-owners which we account for as equity investments. 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 MCO for $40.5 million, spent $17.8 million on various asset acquisitions and paid $8.1 million for growth projects in conjunction with our joint venture co-owners which we account for as equity investments. During 2010, we acquired storage and pipeline assets for $291.3 million and related tank bottom inventories for $53.0 million. Also during 2010, we acquired petroleum products storage tanks at various locations on our refined products pipeline for $29.3 million, and we spent $221.4 million for capital expenditures, which included $45.2 million for maintenance capital and $176.2 million for expansion capital.

Net cash provided (used) by financing activities for the years ended December 31, 2010, 2011 and 2012 was $168.8 million, $(116.4) million and $(158.4) million, respectively. 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 or will be used for general partnership purposes. Also, in January 2012, the cumulative amounts of the January 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. During 2010, we paid cash distributions of $318.8 million to our unitholders. We received net proceeds of $258.4 million from our public offering of limited partner units and $298.9 million, net of discounts, from borrowings under notes. Combined, these net proceeds were used primarily to acquire certain pipeline and storage assets and to repay outstanding borrowings on our revolving credit facility of $175.5 million at that time, with the balance used for general partnership purposes. Additionally, net repayments on our revolving credit facility, including the $175.5 million repayment above, were $86.6 million. Also during 2010, we received proceeds of $16.2 million from the termination and settlement of interest rate swap agreements.

The quarterly distribution amount related to fourth quarter 2012 was $0.50 per unit, which was paid in February 2013. If we are able to meet management's targeted distribution growth of 10% during 2013 and the number of outstanding limited partner units remains at 226.7 million, total cash distributions of approximately $467.8 million will be paid to our unitholders related to 2013.

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, such as those required to maintain equipment reliability and safety and to address environmental regulations; and
- expansion capital expenditures to acquire additional complementary 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 2012, our maintenance capital spending was $64.4 million. For 2013, we expect to increase maintenance capital expenditures for our existing businesses to approximately $75 million due to a number of system upgrades.

In addition to maintenance capital expenditures, we also incur expansion capital expenditures at our existing facilities and acquire new assets. During 2012, we spent $289.8 million for organic growth capital and $74.9 million for growth projects in conjunction with our joint venture co-owners. Based on the progress of expansion projects already underway, including the reversal and conversion of our Longhorn pipeline from refined products to crude oil service, we expect to spend approximately $700 million for expansion capital during 2013, with an additional $290 million in 2014 to complete these projects.

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, 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.

Debt at December 31, 2011 and 2012 was as follows (in thousands):

	December 31,		Weighted-Average Interest Rate at December 31, 2012 (a)
	2011	2012	
Revolving credit facility	$ —	$ —	—%
$250.0 million of 6.45% Notes due 2014	249,844	249,905	6.3%
$250.0 million of 5.65% Notes due 2016	252,037	251,609	5.7%
$250.0 million of 6.40% Notes due 2018	263,477	261,411	5.3%
$550.0 million of 6.55% Notes due 2019	578,521	575,065	5.7%
$550.0 million of 4.25% Notes due 2021	558,932	558,088	4.0%
$250.0 million of 6.40% Notes due 2037	248,964	248,981	6.4%
$250.0 million of 4.20% Notes due 2042	—	248,349	4.2%
Total debt	$ 2,151,775	$ 2,393,408	5.3%

(a) Weighted-average interest rate includes the impact of interest rate swaps, 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 12—*Derivative Financial Instruments* in Item 8 of this Exhibit 99.1 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 outstanding as of December 31, 2011 and 2012 was $2.1 billion and $2.4 billion, respectively. The difference between the face value and carrying value of the debt outstanding is the unamortized portion of various fair value hedges and the unamortized discounts and premiums on debt issuances. Note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives of the associated notes. At December 31, 2012, maturities of our debt were as follows: $0.0 in 2013; $250.0 million in 2014; $0.0 million in 2015; $250.0 million in 2016; $0.0 million in 2017; and $1.9 billion thereafter.

2012 Debt Offering

In November 2012, we issued $250.0 million of 4.20% notes due December 1, 2042 in an underwritten public offering. The notes were issued for the discounted price of 99.3% of par, or $248.3 million. We have used or intend to use the net proceeds from this offering of approximately $245.8 million, after underwriting discounts and offering expenses, for general partnership purposes, including capital expenditures and investments in interest bearing securities or accounts.

Other Debt

Revolving Credit Facility. The total borrowing capacity under our revolving credit facility, which matures in October 2016, is $800.0 million. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.875% to 1.75% based on our credit ratings and amounts outstanding under the facility. Additionally, an unused commitment fee is assessed at a rate from 0.125% to 0.3%, depending on our credit ratings. The unused commitment fee was 0.2% at December 31, 2012. Borrowings under this facility may be used for general purposes, including capital expenditures. As of December 31, 2012, 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. The terms of our revolving credit facility exclude the financial impact of unrealized gains and losses of derivative agreements from the calculation of consolidated debt to EBITDA. We were in compliance with these covenants as of and during the year ended December 31, 2012.

During the years ending December 31, 2010, 2011 and 2012, total cash payments for interest on all indebtedness, excluding the impact of related interest rate swap agreements, were $101.3 million, $111.7 million and $123.3 million, respectively.

Interest Rate Derivatives. 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. 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 in 2014.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2012 (in millions):

	Total	< 1 year	1-3 years	3-5 years	> 5 years
Long-term debt obligations[1]	$ 2,350.0	$ —	$ 250.0	$ 250.0	$ 1,850.0
Interest obligations	1,294.9	133.7	241.6	216.0	703.6
Operating lease obligations	34.3	3.8	6.6	5.5	18.4
Pension and postretirement medical obligations[2]	68.8	16.7	40.9	1.4	9.8
Purchase commitments:					
Product purchase commitments[3]	23.3	23.3	—	—	—
Utility purchase commitments	16.7	4.0	6.3	6.3	0.1
Derivative instruments[4]	—	—	—	—	—
Equity-based incentive awards[5]	48.5	17.4	31.1	—	—
Environmental remediation[6]	9.4	2.8	3.4	3.2	—
Capital project purchase obligations	83.2	83.2	—	—	—
Maintenance obligations	30.0	19.2	10.8	—	—
Other purchase obligations	4.4	2.5	1.8	0.1	—
Total	$ 3,963.5	$ 306.6	$ 592.5	$ 482.5	$ 2,581.9

(1) At December 31, 2012, we had no borrowings outstanding under our revolving credit facility. For purposes of this table, we have reflected no assumed borrowings 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) We have an agreement with a supplier whereby we can purchase up to approximately 600,000 barrels of petroleum products per month until 2014. We have an offsetting agreement with a third party to sell these barrels at the same price as our purchases. Because we account for this buy-sell arrangement on a net basis, neither the product purchases nor the related product sales impact our consolidated statements of income. Related to these agreements, we have entered into a separate buy-or-make-whole agreement with the supplier for 13,000 barrels of petroleum products per day through January 31, 2014. Under the terms of this buy-or-make-whole agreement, if we do not purchase all of the barrels specified in the agreement, our supplier will sell the deficiency barrels in the open market. We are required to reimburse our supplier for any amounts in which they sell these deficiency barrels at prices lower than specified in our buy-or-make-whole agreement. We have not included any amounts in the table above for this commitment because we are unable to determine what the amounts, if any, of that commitment might be.

(4) As of December 31, 2012, we had entered into commodity-related derivative contracts representing 2.5 million barrels of petroleum products that we expect to sell in the future and 0.2 million barrels of petroleum products we expect to purchase in the future. At December 31, 2012, we had recorded a net liability of $7.3 million and made margin deposits of $18.3 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.

(5) Represents the grant date fair value of unit awards accounted for as equity plus the December 31, 2012 re-measured grant date fair value of award grants accounted for as liabilities. The 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, 2012. 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, 2012 and the vesting dates of the awards and completion of the remaining portion of the requisite service periods.

(6) 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 ($3.5 million as of December 31, 2012) 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, 2012). 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 ($4.8 million as of December 31, 2012) 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 Environmental Protection Agency ("EPA") is required to collect the fees if a state does not administer and enforce CAA 185. The Houston-Galveston region was initially determined to be a severe nonattainment area that did not meet its 2007 attainment deadline and, as such, would be subject to CAA 185. The Texas Commission on Environmental Quality ("TCEQ") is currently considering a "Failure to Attain Rule" to implement the requirements of CAA 185. The draft Failure to Attain Rule is anticipated to be adopted in 2013 and is expected to provide for the collection of an annual failure to attain fee for excess emissions. We have certain facilities in the Houston area that will be subject to the TCEQ's Failure to Attain Rule.

Management believes the most likely scenario is that we will be assessed fees for excess emissions at our Houston-area facilities and our estimate of the possible range of loss associated with this matter is from zero to $14.3 million. As of December 31, 2012, we have accrued $10.9 million as a long-term environmental liability related to this matter. Management believes that recent indications with regard to this matter by the TCEQ and the EPA have been favorable to us. The final Failure to Attain Rule is expected to be published in 2013; therefore, it is likely that our estimate of this loss will change in the near term.

Stationary Engine Emission Standards

The EPA has set a May 2013 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 pipeline are subject to these EPA mandates. The EPA rule, which became effective in May 2010, generally anticipates the installation of catalytic converters to the engine exhaust to achieve compliance, which is the solution we are pursuing; however, engine replacements may be required if it is determined that catalytic converters will not achieve the required level of emission reductions. We have received a one-year extension to meet the stationary engine emission standards. If we are not able to modify or replace these engines by May 2014, sections of our refined products pipeline could experience capacity reductions or we could be assessed significant penalties until the required emission reductions are achieved.

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 petroleum 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 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, 2012, our open derivative contracts were as follows:

Open Derivative Contracts Designated as Hedges

- NYMEX contracts for 0.2 million barrels of petroleum products to hedge against price changes in anticipated sales of petroleum products related to our butane blending and fractionation activities, which we are accounting for as cash flow hedges. These contracts mature between January and March 2013. Through December 31, 2012, the cumulative amount of unrealized gains from these agreements was $0.1 million, which did not impact product sales and was recorded as an adjustment to accumulated other comprehensive loss.

- 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 April and November 2013. Through December 31, 2012, the cumulative amount of losses from these agreements was $5.7 million. The cumulative losses from these fair value hedges were recorded as adjustments to the asset being hedged. As a result, none of these cumulative losses impacted product sales.

Open Derivative Contracts Not Designated as Hedges

- NYMEX contracts covering 0.9 million barrels of petroleum products related to our butane blending and fractionation activities. These contracts mature between January and April 2013 and are being accounted for as economic hedges. Through December 31, 2012, the cumulative amount of net unrealized losses associated with these agreements was $6.5 million, all of which was recognized in 2012.

- NYMEX contracts covering 0.7 million barrels of petroleum products related to our pipeline product overages that mature between January and April 2013, which are being accounted for as economic hedges. Through December 31, 2012, the cumulative amount of unrealized losses associated with these agreements was $2.2 million. We recorded these losses as an increase in operating expenses, all of which was recognized in 2012.

- Butane futures agreements to purchase 0.2 million barrels of butane that mature between January and April 2013, which are being accounted for as economic hedges. Through December 31, 2012, the cumulative amount of unrealized gains associated with these agreements was $1.1 million. We recorded these gains as a decrease in product purchases, all of which was recognized in 2012.

Settled Derivative Contracts

Related to physical product sales during 2012, we recognized losses of $30.5 million on NYMEX contracts that did not qualify for hedge accounting treatment that settled during 2012.

Additionally, we recognized gains of $2.8 million on NYMEX contracts designated as cash flow hedges that settled during 2012 related to physical product sales during 2012.

Product Sales Revenues

The following tables provide a summary of the mark-to-market gains and losses associated with NYMEX contracts and the accounting periods in which the gains and losses impacted product sales revenues in our consolidated statements of income for the years ended December 31, 2010, 2011 and 2012 (in millions):

2010		
NYMEX losses recorded in 2010 that were associated with physical product sales during 2010	$	(6.8)
NYMEX losses recorded in 2010 that were associated with future physical product sales		(14.9)
Total NYMEX losses that impacted product sales revenues during 2010	$	(21.7)
2011		
NYMEX losses recorded in 2011 that were associated with physical product sales during 2011	$	(20.7)
NYMEX gains recorded in 2011 that were associated with future physical product sales		5.2
Total NYMEX losses that impacted product sales revenues during 2011	$	(15.5)
2012		
NYMEX losses recorded in 2012 that were associated with physical product sales during 2012	$	(27.7)
NYMEX losses recorded in 2012 that were associated with future physical product sales		(6.5)
Total NYMEX losses that impacted product sales revenues during 2012	$	(34.2)

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 one-third of our tariffs are subject to this indexing methodology while the remaining two-thirds of the 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 increased virtually all of our tariffs by 8.6% on July 1, 2012. Further, based on preliminary estimates of the PPI-FG for 2012, we expect to increase virtually all of our tariffs by 4.6% on July 1, 2013.

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) changes in federal, state and local environmental regulations could significantly change the amount of our environmental liabilities.

A defined process for project reviews 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, 2010 were as follows (in millions):

Balance	2011		Balance	2012		Balance
12/31/10	Accruals	Expenditures	12/31/11	Accruals	Expenditures	12/31/12
$ 32.8	$ 29.2	$ (12.4)	$ 49.6	$ 13.2	$ (14.5)	$ 48.3

During 2011, we increased our environmental liability accruals by $29.2 million, of which $10.7 million was related to potential air emission fees for the period of 2008 through 2011 (see *Clean Air Act - Section 185 Liability*, above), $10.6 million was due to product releases which occurred during 2011 and $7.9 million related to historical releases. At December 31, 2011, we had recognized $7.7 million of receivables from insurance carriers associated with environmental claims.

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.

We based our environmental liabilities at December 31, 2012 on estimates that are subject to change, and any changes to these estimates would affect our results of operations and financial position. Any increase in our environmental liabilities would decrease our operating profit and net income by the same amount, which would negatively impact basic and diluted net income per limited partner unit.

Pension and Postretirement Obligations

We sponsor two union pension plans covering certain employees (“USW plan” and “IUOE plan”), a pension plan for all non-union employees (“Salaried plan”) and an other 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	$ (3,657)	$ 4,575	$ (19,971)	$ 25,457
Expected long-term rate of return on plan assets	(865)	865	—	—
Rate of compensation increase	3,211	(647)	8,052	(8,051)
Other postretirement benefits:				
Discount rate	(238)	296	(2,052)	2,675
Assumed health care cost trend rate	412	(328)	2,441	(1,942)

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	$ 124	$ (107)
Rate of compensation increase	$ (2,773)	$ 2,773

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 2009, 2010 and 2012 benefit investment performances were greater than our expected rates of return for these years, the investment performance for 2011 was 4.2% 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 2009 through 2011, we estimated the long-term rate of return on the IUOE plan assets at 3.3% primarily because of the asset allocation of that fund; however, with the recent change in asset allocations for the fund, we increased this rate to be in line with the Salaried and USW plans. The 2012 actual return on plan assets for our Salaried, USW and IUOE pension plans was a gain of approximately 10.5%, 11.0% and 11.2%, respectively. Through December 2012, the weighted-average rate of return on pension plan assets for the nine-year period we have controlled the plans was approximately 6.0%, 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.

Equity-Based Incentive Compensation Expense

Each year, the compensation committee of our general partner's board of directors has approved performance-based award grants of phantom units to key employees. The majority of the awards granted in 2010, 2011 and 2012 have three-year vesting periods and payouts of the performance awards are based on actual results as measured against a financial metric goal. The financial metric for the 2010, 2011 and 2012 performance awards was distributable cash flow per limited partner unit outstanding excluding the impact of certain commodity-related activities ("adjusted DCF"). Generally, unit awards are granted in January of the first year of the three-year vesting period of the awards. At the time the awards are granted, the compensation committee establishes threshold, target and stretch adjusted DCF metric goals for the third year of those awards' vesting period. Adjusted DCF performance in that third year determines the payout percentage of the awards as follows: adjusted DCF at or below the threshold metric results in a 0% payout, adjusted DCF at the target metric results in a 100% payout and adjusted DCF at or above the stretch metric results in a 200% payout, with results between the established metrics being interpolated.

Under Accounting Standards Codification ("ASC") 718, *Compensation-Stock Compensation,* we classify performance awards as either equity or liabilities. Each period's 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 reduced by the present value of any projected per unit distributions during the remainder of the requisite service period that will not be paid to the participant. Each period's 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 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.

Accounting for these performance awards requires management to make a number of judgments and assumptions; however, the key assumption in determining our equity-based compensation expense is management's estimate of the final payout percentage, which can range from 0% to 200% of the performance award. At the end of each accounting period, management estimates the expected payout of each year's performance award. Changes in this estimate can significantly affect equity-based compensation expense, particularly when those changes are made in the last year of the three-year vesting period. During the first year of a performance award's vesting period, the estimated payout percentage is generally at 100% because management assumes that actual adjusted DCF results will be at target unless there are exceptionally strong indicators to the contrary. During the second year of the vesting period, management adjusts the estimated payout percentages from 100% only if there are strong indicators that actual adjusted DCF for the last year of the vesting period will be higher or lower than target. Management evaluates the strength of the economy, results from completed acquisitions, expectations of results from organic growth capital projects, expense and revenue trends and a number of other factors when making these determinations. During the third and final year of the vesting period, management adjusts the payout percentage primarily to reflect actual and forecast adjusted DCF results as the year progresses and finally to the actual payout percentage at the end of the vesting period.

During 2010, management assumed the payout percentage for the 2010 performance awards would be 100% because there were no exceptionally strong indicators that adjusted DCF for the final year of the vesting period would be different than target. Equity-based compensation expense for these awards for the year ended December 31, 2010 was $2.5 million. During 2011, management increased the estimated payout percentage for these awards to 125% based on strong actual and anticipated acquisition and capital project results. Equity-based compensation expense for these awards for the year ended December 31, 2011 was $4.7 million. During second and third quarter 2012, we increased the accruals for these awards to 150% and 168%, respectively, based on the latest forecast for adjusted DCF for 2012 and during fourth quarter 2012 we adjusted the accrual for these awards to the actual calculated payout percentage of 182%. Equity-based compensation expense for these awards for the year ended December 31, 2012 was $8.7 million.

During 2011, management initially assumed the payout percentage for the 2011 performance awards would be 100%; however, during the fourth quarter of 2011, because of the exceptionally strong indicators that adjusted DCF for the final year of the vesting period would be above target, the estimated payout percentage for these awards was increased to 125%. The exceptionally strong indicators of higher adjusted DCF for the 2013 year is primarily due to anticipated capital project results. Equity-based compensation expense for these awards for the year ended December 31, 2011 was $3.7 million. During 2012, management increased the estimated payout percentage for these awards to 175%, again based on exceptionally strong indicators of adjusted DCF for the 2013 year. Equity-based compensation expense for these awards for the year ended December 31, 2012 increased to $7.2 million.

During 2012, management initially assumed the payout percentage for the 2012 performance awards would be 100%; however, because the adjusted DCF for the 2014 fiscal year is projected to be exceptionally strong, the estimated payout percentage for these awards was increased to 150%. The strong projections for the 2014 fiscal year are primarily related to the anticipated impact on our results from the Longhorn pipeline reversal project and from the BridgeTex pipeline project. Equity-based compensation expense for these awards for the year ended December 31, 2012 was $4.5 million.

Goodwill and Impairment of Long-Lived Assets

Goodwill. At December 31, 2011 and 2012, 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 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 and 2012, we do not believe our goodwill was impaired, and we did not record a charge associated with ASC 350 during 2010, 2011 or 2012.

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.

We recognized no impairments during 2010 and impairments recognized during 2011 and 2012 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 is effective for annual and interim periods beginning after December 15, 2012 and is to be applied prospectively. Our adoption of this standard will 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 will not have a material impact on our results of operations, financial position or cash flows.

In September 2011, the FASB issued ASU No. 2011-08, *Intangibles-Goodwill and Other (Topic 350): Testing Goodwill for Impairment*, which modifies the test for goodwill intangibles. Under this ASU, entities are no longer required to calculate the fair value of a reporting unit unless they determine that it is more likely than not that a reporting unit's fair value is less than its carrying amount. This ASU was effective for periods beginning after December 15, 2011. Our adoption of this ASU in the first quarter of 2012 had no impact on our results of operations, financial position or cash flows.

In June 2011, the FASB issued ASU No. 2011-05, *Comprehensive Income*, which requires either that the income statement include other comprehensive income or a separate comprehensive income statement be reported immediately after the income statement. The option to report other comprehensive income in the statement of owner's equity has been eliminated. This ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, with early adoption permitted. We adopted this ASU in the first quarter of 2011, which had no impact on our results of operations, financial position or cash flows.

In May 2011, the FASB issued ASU No. 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* which amends ASC 820, *Fair Value Measurement*. This ASU amends ASC 820 and results in a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between GAAP and international financial reporting standards. The amendments in this ASU change the wording used to describe many of the requirements in GAAP for measuring fair value and for disclosing information about fair value measurements; however, the amendment’s requirements do not extend the use of fair value accounting, and for many of the requirements, the FASB does not intend for the amendments to result in a change in the application of the requirements in the “Fair Value Measurement” Topic of the Codification. Additionally, ASU No. 2011-04 includes some enhanced disclosure requirements, including an expansion of the information required for Level 3 fair value measurements. This ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. Our adoption of this ASU in the first quarter of 2012 did not have a material impact on our results of operations, financial position or cash flows.

Related Party Transactions

We own a 50% interest in Osage and receive a management fee for its operation. We received operating fees from Osage of $0.8 million each year in 2010, 2011 and 2012. We reported these fees as affiliate management fee revenue on our consolidated statements of income.

We own a 50% interest in Texas Frontera, which has constructed 0.8 million barrels of refined products storage at our Galena Park, Texas terminal. These tanks, which began operation in October 2012, are leased to an affiliate of Texas Frontera under a long-term lease agreement. Additionally, we have constructed certain infrastructure assets at our Galena Park terminal which allow for the operation of the Texas Frontera tanks. For the year ended December 31, 2012, we contributed $4.2 million to Texas Frontera, of which $2.5 million was paid in cash but $1.7 million was subsequently reimbursed to us for constructed infrastructure assets. We received management fees from Texas Frontera of $0.2 million in 2012. We reported these fees as affiliated management fee revenue on our consolidated statements of income.

We own a 50% interest in Double Eagle, which is in the process of constructing a 140-mile pipeline that will connect to an existing pipeline segment owned by an affiliate of Double Eagle. Once completed, Double Eagle will transport condensate from the Eagle Ford shale formation to our terminal in Corpus Christi, Texas. For the year ended December 31, 2012, we contributed $39.1 million for construction funding requests from Double Eagle. We expect these assets to be fully operational by the second half of 2013.

We own a 50% interest in BridgeTex, which is in the process of constructing a 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. For the year ended December 31, 2012, we contributed $31.8 million for construction funding requests from BridgeTex. We received construction management fees from BridgeTex of $0.9 million in 2012. We reported these fees as affiliate management fee revenue on our consolidated statements of income.

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 petroleum products from subsidiaries of Targa. For the years ended December 31, 2010, 2011 and 2012, we made purchases from subsidiaries of Targa of $1.8 million,

$11.7 million and $27.4 million, respectively. These purchases were made on the same terms as comparable third-party transactions.

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 12 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.

Forward-Looking Statements

Certain matters discussed in this Exhibit 99.1 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 Exhibit 99.1.

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 Exhibit 99.1:

- 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 pipelines owned and operated by third parties and connected to our assets;
- changes in demand for storage in our refined products and crude oil 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 for which we are not adequately insured;
- the treatment of us as a corporation for federal or state income tax purposes or if we become subject to significant forms of other taxation or more aggressive enforcement or increased assessments under existing forms of taxation;
- our ability to identify expansion projects or to complete identified expansion projects on time and at projected costs;
- our ability to make and integrate accretive acquisitions and joint ventures and successfully execute our business strategy;
- uncertainty of estimates, including accruals and costs of environmental remediation;
- our ability to cooperate with and rely on our joint venture co-owners;
- actions by rating agencies concerning our credit ratings;
- our ability to timely obtain and maintain all necessary approvals, consents and permits required to operate our existing assets and any new or modified assets;
- our ability to promptly obtain all necessary 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 that could impact our ability to produce gasoline volumes through our butane blending activities or that could require significant capital outlays for compliance;

- changes in laws and regulations to which we or our customers are or 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;
- 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 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, 2012 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 ("COSO" criteria). As of December 31, 2012, 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, 2012 based on COSO criteria.

Ernst & Young LLP, the independent registered public accounting firm that audited our consolidated financial statements included in our Annual Report on Form 10-K, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2012. The report, which expresses an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2012, is included therein 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
on Internal Control Over Financial Reporting**

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, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (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 Magellan Midstream Partners, L.P.'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, 2012, based on the COSO criteria.

We have also 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, 2012 and 2011, 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, 2012 and our report dated February 22, 2013 (except for Notes 1, 2, 4, 8, 15 and 21 as to which the date is April 29, 2013) expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 22, 2013

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, 2012 and 2011, 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, 2012. 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, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 22, 2013,
except for Notes 1, 2, 4, 8, 15 and 21 as to which the date is
April 29, 2013

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

	Year Ended December 31,		
	2010	2011	2012
Transportation and terminals revenues	$ 793,599	$ 893,369	$ 970,744
Product sales revenues	763,090	854,528	799,382
Affiliate management fee revenue	758	770	1,948
Total revenues	1,557,447	1,748,667	1,772,074
Costs and expenses:			
Operating	282,212	306,415	328,454
Product purchases	668,585	706,270	657,108
Depreciation and amortization	108,668	121,179	128,012
General and administrative	95,316	98,669	109,403
Total costs and expenses	1,154,781	1,232,533	1,222,977
Equity earnings	5,732	6,763	2,961
Operating profit	408,398	522,897	552,058
Interest expense	96,379	108,869	117,981
Interest income	(140)	(61)	(107)
Interest capitalized	(2,943)	(3,174)	(6,195)
Debt placement fee amortization	1,401	1,831	2,087
Other expense	750	—	—
Income before provision for income taxes	312,951	415,432	438,292
Provision for income taxes	1,371	1,866	2,622
Net income	$ 311,580	$ 413,566	$ 435,670
Allocation of net income (loss):			
Limited partners' interest	$ 311,977	$ 413,629	$ 435,670
Non-controlling owners' interest	(397)	(63)	—
Net income	$ 311,580	$ 413,566	$ 435,670
Basic and diluted net income per limited partner unit	$ 1.42	$ 1.83	$ 1.92
Weighted average number of limited partner units outstanding used for basic net income per unit calculation	218,970	225,674	226,369
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation	219,122	225,974	226,608

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2010	**2011**	**2012**
Net income	$ 311,580	$ 413,566	$ 435,670
Other comprehensive income:			
Net gain on interest rate cash flow hedges	—	—	10,977
Net gain (loss) on commodity cash flow hedges	(4,283)	7,739	2,912
Reclassification of net gain on interest rate cash flow hedges to interest expense	(164)	(164)	(164)
Reclassification of net loss (gain) on commodity cash flow hedges to product sales revenues	5,438	(7,739)	(2,760)
Reclassification of loss on discontinuance of commodity cash flow hedge to product sales revenues	591	—	—
Settlement cost and amortization of prior service credit and actuarial loss	106	1,117	2,962
Adjustment to recognize the funded status of postretirement plans	(4,783)	(37,058)	(1,784)
Total other comprehensive income (loss)	(3,095)	(36,105)	12,143
Comprehensive income	308,485	377,461	447,813
Comprehensive loss attributable to non-controlling owners’ interest in consolidated subsidiaries	(397)	(63)	—
Comprehensive income attributable to partners’ capital	$ 308,882	$ 377,524	$ 447,813

See notes to consolidated financial statements.

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

	December 31, 2011	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 209,620	$ 328,278
Trade accounts receivable (less allowance for doubtful accounts of $68 and $5 at December 31, 2011 and 2012, respectively)	82,497	91,114
Other accounts receivable	10,079	12,329
Inventory	258,860	221,888
Energy commodity derivatives contracts, net	4,914	—
Energy commodity derivatives deposits, net	26,917	18,304
Reimbursable costs	5,891	4,863
Other current assets	13,412	23,502
Total current assets	612,190	700,278
Property, plant and equipment	4,080,484	4,408,550
Less: accumulated depreciation	830,762	943,248
Net property, plant and equipment	3,249,722	3,465,302
Investment in non-controlled entities	35,594	107,356
Long-term receivables	2,534	5,135
Goodwill	53,260	53,260
Other intangibles (less accumulated amortization of $14,813 and $16,715 at December 31, 2011 and 2012, respectively)	15,176	13,274
Debt placement costs (less accumulated amortization of $5,799 and $7,886 at December 31, 2011 and 2012, respectively)	14,615	15,080
Tank bottom inventory	59,473	58,493
Other noncurrent assets	2,437	1,889
Total assets	$ 4,045,001	$ 4,420,067
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 66,384	$ 112,002
Accrued payroll and benefits	30,184	32,434
Accrued interest payable	40,547	42,059
Accrued taxes other than income	27,570	33,089
Environmental liabilities	17,852	14,442
Deferred revenue	39,983	46,371
Accrued product purchases	59,800	72,049
Energy commodity derivatives contracts, net	—	7,338
Other current liabilities	28,735	32,836
Total current liabilities	311,055	392,620
Long-term debt	2,151,775	2,393,408
Long-term pension and benefits	67,080	68,134
Other noncurrent liabilities	19,905	16,382
Environmental liabilities	31,783	33,821
Commitments and contingencies		
Partners' capital:		
Limited partner unitholders (225,473 units and 226,201 units outstanding at December 31, 2011 and 2012, respectively)	1,510,604	1,550,760
Accumulated other comprehensive loss	(47,201)	(35,058)
Total partners’ capital	1,463,403	1,515,702
Total liabilities and partners' capital	$ 4,045,001	$ 4,420,067

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2010	**2011**	**2012**
Operating Activities:			
Net income	$ 311,580	$ 413,566	$ 435,670
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	108,668	121,179	128,012
Debt placement fee amortization	1,401	1,831	2,087
Loss on sale and retirement of assets	1,062	8,599	12,625
Equity earnings	(5,732)	(6,763)	(2,961)
Distributions from equity investments	4,853	5,598	2,961
Equity-based incentive compensation expense	18,899	17,710	21,036
Settlement cost and amortization of prior service credit and actuarial loss	106	1,117	2,962
Changes in components of operating assets and liabilities (Note 3)	(16,181)	14,486	42,699
Net cash provided by operating activities	424,656	577,323	645,091
Investing Activities:			
Property, plant and equipment:			
Additions to property, plant and equipment	(221,419)	(199,665)	(354,168)
Proceeds from sale and disposition of assets	8,300	6,299	1,056
Increase (decrease) in accounts payable related to capital expenditures	(3,432)	2,126	55,133
Acquisitions of businesses	(291,292)	—	—
Acquisition of tank bottom inventory	(53,017)	—	—
Acquisition of assets	(29,300)	(17,807)	—
Acquisition of non-controlling owners' interests	—	(40,500)	—
Investment in non-controlled entities	—	(8,094)	(74,934)
Distributions in excess of equity investment earnings	—	—	4,832
Other	—	(1,100)	—
Net cash used by investing activities	(590,160)	(258,741)	(368,081)
Financing Activities:			
Distributions paid	(318,817)	(350,892)	(403,485)
Net repayments under revolver	(86,600)	(15,000)	—
Borrowings under long-term notes	298,899	260,914	248,345
Debt placement costs	(2,378)	(4,575)	(2,552)
Net receipt from interest rate derivatives	16,238	5,926	10,977
Increase (decrease) in outstanding checks	2,393	(5,408)	1,364
Settlement of tax withholdings on long-term incentive compensation	(3,371)	(7,410)	(13,001)
Issuance of limited partner units	258,407	—	—
Capital contributed by non-controlling owners	4,361	—	—
Costs associated with the simplification of capital structure	(313)	—	—
Net cash provided (used) by financing activities	168,819	(116,445)	(158,352)
Change in cash and cash equivalents	3,315	202,137	118,658
Cash and cash equivalents at beginning of period	4,168	7,483	209,620
Cash and cash equivalents at end of period	$ 7,483	$ 209,620	$ 328,278
Supplemental non-cash financing activities:			
Issuance of MMP limited partner units in settlement of long-term incentive plan awards	$ 2,034	$ 4,315	$ 7,295
Non-cash capital contributed by non-controlling owners	$ 10,299	$ —	$ —

See notes to consolidated financial statements.

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

	Partners' Capital			
	Limited Partners	Partners' Accumulated Other Comprehensive Loss	Non-controlling Owners' Interest	Total Owners' Equity
Balance, January 1, 2010	$ 1,204,355	$ (8,001)	$ —	$ 1,196,354
Comprehensive income:				
Net income (loss)	311,977	—	(397)	311,580
Net loss on commodity cash flow hedges	—	(4,283)	—	(4,283)
Reclassification of net gain on interest rate cash flow hedges to interest expense	—	(164)	—	(164)
Reclassification of net loss on commodity cash flow hedges to product sales revenues	—	5,438	—	5,438
Reclassification of loss on discontinuance of commodity cash flow hedge to product sales revenues	—	591	—	591
Amortization of prior service credit and actuarial loss	—	106	—	106
Adjustment to recognize the funded status of postretirement plans	—	(4,783)	—	(4,783)
Total comprehensive income (loss)	311,977	(3,095)	(397)	308,485
Distributions	(318,817)	—	—	(318,817)
Issuance of MMP limited partner units	258,407	—	—	258,407
Equity method incentive compensation expense	12,233	—	—	12,233
Issuance of MMP limited partner units in settlement of long-term incentive plan awards	2,034	—	—	2,034
Settlement of tax withholdings on long-term incentive compensation	(3,371)	—	—	(3,371)
Capital contributed by non-controlling owners	—	—	14,660	14,660
Other	(414)	—	—	(414)
Balance, December 31, 2010	1,466,404	(11,096)	14,263	1,469,571
Comprehensive income:				
Net income (loss)	413,629	—	(63)	413,566
Net gain on commodity cash flow hedges	—	7,739	—	7,739
Reclassification of net gain on interest rate cash flow hedges to interest expense	—	(164)	—	(164)
Reclassification of net gain on commodity cash flow hedges to product sales revenues	—	(7,739)	—	(7,739)
Settlement cost and amortization of prior service credit and actuarial loss	—	1,117	—	1,117
Adjustment to recognize the funded status of postretirement plans	—	(37,058)	—	(37,058)
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

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

	Partners' Capital			
	Limited Partners	Partners' Accumulated Other Comprehensive Loss	Non-controlling Owners' Interest	Total Owners' Equity
Balance, January 1, 2012	$ 1,510,604	$ (47,201)	$ —	$ 1,463,403
Comprehensive income:				
Net income	435,670	—	—	435,670
Net gain on interest rate cash flow hedges	—	10,977	—	10,977
Net gain on commodity cash flow hedges	—	2,912	—	2,912
Reclassification of net gain on interest rate cash flow hedges to interest expense	—	(164)	—	(164)
Reclassification of net gain on commodity cash flow hedges to product sales revenues	—	(2,760)	—	(2,760)
Amortization of prior service credit and actuarial loss	—	2,962	—	2,962
Adjustment to recognize the funded status of postretirement plans	—	(1,784)	—	(1,784)
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

See 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 system, our independent terminals, our ammonia pipeline as well as our butane blending and fractionation activities, each of which is briefly described below:

- Our refined products pipeline consists of approximately 8,800 miles of pipeline and 49 terminals that provide transportation, storage and distribution services. Our refined products pipeline covers a 14-state area extending from Texas through the Midwest to Colorado, North Dakota, Minnesota, Wisconsin and Illinois. 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 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 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 revenues 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 revenues principally from volume-based fees for the transportation of ammonia on our pipeline system.

Crude Oil. Our crude oil segment includes a crude oil terminal in Cushing, Oklahoma, our Longhorn crude oil pipeline, our Houston-area crude oil distribution system and the crude oil and condensate storage at our East Houston and Corpus Christi, Texas terminals. Additionally, our crude oil segment includes our ownership interest in three equity investments. A brief description of these operations is as follows:

- Our Longhorn crude oil pipeline consists of approximately 450 miles of pipeline which originates from third party pipeline connections in Crane, Texas for deliveries to Houston-area refineries and pipelines. The Longhorn pipeline will begin crude oil service in early 2013;

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

- 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 usable crude oil storage. This terminal principally serves refiners, marketers and traders. We earn revenues primarily from leasing tanks as well as from throughput fees; and

- We own more than 200 miles of pipeline in Kansas and Oklahoma that we lease to third parties for crude oil service. We earn revenues from these pipeline segments for capacity reserved even if not used by the customer.

Our crude oil segment also includes ownership interests in the following ventures:

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

- a 50% interest in Double Eagle Pipeline LLC ("Double Eagle"), which is constructing a 140-mile pipeline to connect to a 50-mile pipeline owned by a related party entity to transport condensate to our terminal at Corpus Christi, Texas. This pipeline is expected to be fully operational by the second half of 2013; 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-area 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 throughout four states. 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 25 million barrels. Because the rates charged at these terminals are unregulated, the marketplace determines the prices we can charge for our services. We earn revenues 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 a refined products storage company that owns 0.8 million barrels of storage located at our Galena Park terminal.

Two-for-One Unit Split. In August 2012, our general partner's board of directors approved a two-for-one split of our limited partner units, which was completed on October 12, 2012. We have retrospectively restated all limited partner unit and per unit amounts in this report, including earnings per limited partner unit, the weighted average number of limited partner units outstanding for basic and diluted net income per limited partner unit, limited partner units outstanding and per unit cash distribution amounts, for each respective period presented.

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

Cash Equivalents. Cash and cash equivalents include demand and time deposits and 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, 2011 and 2012, we believed that 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. During 2012, we recorded a lower-of-average-cost-or-market adjustment of $2.0 million to our transmix inventory. This adjustment was recorded as a component of product purchases on the consolidated statement of income included with these financial statements. Our inventory also includes our pipeline over/short product.

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 7—*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. 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 $3.9 million liability associated with anticipated tank liner and seal replacements, we have recorded no 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 undistributed 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 as of the date of the equity investment. Our unamortized excess net investment was $16.5 million and $15.8 million at December 31, 2011 and 2012, 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 2010, 2011 or 2012.

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, 2011 and 2012. Our reported goodwill at December 31, 2012 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 multiple for terminal value. We use October 1 as our impairment measurement test date and have determined that our goodwill was not impaired as of October 1, 2010, 2011 or 2012. 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 4 years up to 25 years. The weighted-average asset life of our other intangible assets at December 31, 2012 was approximately 6 years. We adjust the useful lives 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 2010, 2011 and 2012. Amortization of other intangible assets was $2.0 million, $2.8 million and $1.9 million in 2010, 2011 and 2012, respectively, of which $0.6 million was charged against transportation and terminals revenues in each year during 2010, 2011 and 2012.

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, 2012, our tank bottom inventory consisted of 0.7 million barrels of crude oil with a carrying value of $58.5 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, 2011 and 2012 was $6.4 million and $5.5 million, respectively, which were recorded as increases to the tank bottom inventory.

Assets Held for Sale. We classify long-lived assets to be disposed of through sales that meet specific criteria as held for sale. We cease depreciating those assets effective on the date the asset is classified as held for sale. We record those assets at the lower of their carrying value or the estimated fair value less the cost to sell. Until the assets are disposed of, an estimate of the fair value is re-determined when related events or circumstances change. We had no assets classified as held for sale during 2010 or 2012. In October 2011, based on a plan for the potential sale of our ammonia pipeline, we classified this asset as held for sale. As of December 31, 2011, our ammonia pipeline no longer met the criteria as a held-for-sale asset; therefore, we reclassified this asset as held and used. The adjustments to the carrying amount of our ammonia pipeline due to its reclassification as held and used were insignificant.

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 were not material in 2010, 2011 and 2012.

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.

Paid-Time Off Benefits. We recognize liabilities for paid-time off benefits when earned. Paid-time off liabilities were $11.9 million and $12.8 million at December 31, 2011 and 2012, 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 revenues. We reclassify gains and losses from contracts that qualify as cash flow hedges from other comprehensive income to product sales revenues 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 revenues, 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 product purchases, 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.

Revenue Recognition. We recognize pipeline transportation revenues when shipments are complete. 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 revenues 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 products 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. 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 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.

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. The performance-based awards granted in 2010 contained partial distribution equivalent rights (with respect to distributions in excess of $1.42 per unit annually) and the performance-based awards granted in 2011 and 2012 contain full distribution equivalent rights. Other than certain awards granted to our executive officers, the retention awards granted do not 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. We calculate the per unit fair value of equity awards as the closing price of our limited partner units on the grant date reduced by the present value of any projected per unit distributions during the requisite service period that will not be paid to the participant. 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 reduced by the present value of any projected per unit distributions during the remainder of the requisite service period that will not be paid to the participant. 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 200% of the amount of the award. Additionally, 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.

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 use the risk-free interest rate as the discount rate in calculating fair value of the equity and liability awards. 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. Additionally, the distribution equivalent rights associated with the 2010 award grants were paid out in cash. Phantom units issued to our directors are settled in cash in January of the year following their death or resignation from the board.

The number of equity-based performance and retention unit award grants as well as the number of phantom units granted under our director deferred compensation plan that were outstanding at the time of the two-for-one limited partner unit split in October 2012 were adjusted for this split. Because these award grants included an anti-dilution feature designed to equalize the intrinsic value of the award grants as a result of the split, the fair value of the award grants immediately before and after the split were unchanged.

Contingencies and Environmental. Environmental expenditures are expensed 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 except for those instances where the amounts and timing of the future payments are fixed or reliably determinable. We use the risk-free interest rate to calculate the present value of discounted environmental liabilities. 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 and outside engineering, consulting and law 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. 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.

At December 31, 2012, expected payments on our discounted environmental liabilities were $0.1 million in 2013, $0.1 million in 2014, $0.1 million in 2015, $1.1 million in 2016, less than $0.1 million in 2017 and $0.9 million for all periods thereafter. The table below sets forth the reconciliation of our undiscounted environmental liabilities to amounts reported on our consolidated balance sheets (in thousands). See Note 16–*Commitments and Contingencies* for a discussion of the changes in our environmental liabilities between December 31, 2011 and December 31, 2012.

	December 31, 2011	December 31, 2012
Aggregated undiscounted environmental liabilities	$ 55,012	$ 48,719
Amount of discount on environmental liabilities	(5,377)	(456)
Environmental liabilities, as reported	$ 49,635	$ 48,263

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. The net income per unit amounts included in these financial statements have been retrospectively restated for all periods presented for the two-for-one split of our limited partner units, which was completed in October 2012.

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.

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

	Derivative Gains (Losses)	Pension and Postretirement Liabilities	Accumulated Other Comprehensive Loss*
Balance, January 1, 2010	$ 1,743	$ (9,744)	$ (8,001)
Net loss on commodity cash flow hedges	(4,283)	—	(4,283)
Reclassification of net gain on interest rate cash flow hedges to interest expense	(164)	—	(164)
Reclassification of net loss on commodity cash flow hedges to product sales revenues	5,438	—	5,438
Reclassification of loss on discontinuance of commodity cash flow hedge to product sales revenues	591	—	591
Amortization of prior service credit and actuarial loss	—	106	106
Adjustment to recognize the funded status of postretirement plans	—	(4,783)	(4,783)
Balance, December 31, 2010	3,325	(14,421)	(11,096)
Net gain on commodity cash flow hedges	7,739	—	7,739
Reclassification of net gain on interest rate cash flow hedges to interest expense	(164)	—	(164)
Reclassification of net gain on commodity cash flow hedges to product sales revenues	(7,739)	—	(7,739)
Settlement cost and amortization of prior service credit and actuarial loss	—	1,117	1,117
Adjustment to recognize the funded status of postretirement plans	—	(37,058)	(37,058)
Balance, December 31, 2011	3,161	(50,362)	(47,201)
Net gain on interest rate cash flow hedges	10,977	—	10,977
Net gain on commodity cash flow hedges	2,912	—	2,912
Reclassification of net gain on interest rate cash flow hedges to interest expense	(164)	—	(164)
Reclassification of net gain on commodity cash flow hedges to product sales revenues	(2,760)	—	(2,760)
Amortization of prior service credit and actuarial loss	—	2,962	2,962
Adjustment to recognize the funded status of postretirement plans	—	(1,784)	(1,784)
Balance, December 31, 2012	$ 14,126	$ (49,184)	$ (35,058)

* Includes amounts allocated to the non-controlling owners' interest.

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 is effective for annual and interim periods beginning after December 15, 2012 and is to be applied prospectively. Our adoption of this standard will 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 will not have a material impact on our results of operations, financial position or cash flows.

In September 2011, the FASB issued ASU No. 2011-8, *Intangibles-Goodwill and Other (Topic 350): Testing Goodwill for Impairment*, which modifies the test for goodwill intangibles. Under this ASU, entities have the option to apply a qualitative assessment in determining whether goodwill is impaired. This ASU was effective for periods beginning after December 15, 2011. We elected not to adopt this standard for our 2012 annual goodwill impairment testing.

In June 2011, the FASB issued ASU No. 2011-5, *Comprehensive Income*, which requires either that the income statement include other comprehensive income or a separate comprehensive income statement be reported immediately after the income statement. The option to report other comprehensive income in the statement of owner's equity has been eliminated. This ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, with early adoption permitted. We adopted this ASU in the first quarter of 2011, which had no impact on our results of operations, financial position or cash flows.

In May 2011, the FASB issued ASU No. 2011-4, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* which amends ASC 820, *Fair Value Measurement*. This ASU amends ASC 820 and results in a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between GAAP and international financial reporting standards. The amendments in this ASU change the wording used to describe many of the requirements in GAAP for measuring fair value and for disclosing information about fair value measurements; however, the amendment's requirements do not extend the use of fair value accounting, and for many of the requirements, the FASB does not intend for the amendments to result in a change in the application of the requirements in the "Fair Value Measurement" Topic of the Codification. Additionally, ASU No. 2011-4 includes some enhanced disclosure requirements, including an expansion of the information required for Level 3 fair value measurements. This ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. Our adoption of this ASU in the first quarter of 2012 did not have a material impact on our results of operations, financial position or cash flows.

3. Consolidated Statements of Cash Flows

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

	Year Ended December 31,		
	2010	2011	2012
Restricted cash	$ (14,379)	$ 14,379	$ —
Trade accounts receivable and other accounts receivable	(17,173)	5,791	(10,867)
Inventory	(23,407)	(42,452)	36,972
Energy commodity derivatives contracts, net of derivatives deposits	3,694	(19,782)	16,097
Reimbursable costs	(590)	7,979	1,028
Accounts payable	7,794	20,226	(11,175)
Accrued payroll and benefits	2,093	(2,209)	2,250
Accrued interest payable	2,922	4,069	1,512
Accrued taxes other than income	5,378	617	5,519
Accrued product purchases	10,527	12,476	12,249
Current and noncurrent environmental liabilities	(2,038)	16,861	(1,372)
Other current and noncurrent assets and liabilities	8,998	(3,469)	(9,514)
Total	$ (16,181)	$ 14,486	$ 42,699

At December 31, 2010, 2011 and 2012, the long-term pension and benefits liability was increased by $4.8 million, $37.1 million and $1.8 million, respectively, resulting in a corresponding increase 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. Acquisitions

Acquisitions of Assets

In April 2010, we acquired various storage tanks already connected to our refined products pipeline at Des Moines, Iowa, El Dorado, Kansas and Glenpool and Tulsa, Oklahoma for $29.3 million. We accounted for these purchases as the acquisition of assets. The operating results of these assets have been included in our refined products segment from the acquisition date.

In January 2011, we acquired the remaining 50% undivided interest in our Southlake, Texas terminal. We accounted for this purchase as an acquisition of assets. The operating results of the Southlake terminal are reported in our refined products segment.

In April 2011, we acquired an approximate 38-mile pipeline connected to our refined products pipeline at Reagan, Texas. We accounted for this purchase as an acquisition of assets. The operating results of these assets have been included in our refined products segment from the acquisition date.

In May 2011, we acquired refined products storage tanks in Riverside, Missouri. We accounted for this purchase as an acquisition of assets. The operating results of these assets have been included in our refined products segment from the acquisition date.

Collectively, the costs for these 2011 asset acquisitions were $17.8 million.

Acquisition of Non-Controlling Owners' Interest

In February 2011, we acquired a private investment group's common equity in Magellan Crude Oil, LLC ("MCO") for $40.5 million, which represented all of the non-controlling owners' interest in subsidiaries on our consolidated balance sheet. The operating results of MCO, which is engaged in crude oil storage activities in Cushing, Oklahoma, are reported in our crude oil segment.

Acquisition of Business

In September 2010, we acquired an aggregate 7.8 million barrels of crude oil storage in the Cushing, Oklahoma area and more than 100 miles of active petroleum pipelines in the Houston, Texas area from BP Pipelines (North America), Inc. ("BP") for $291.3 million. We accounted for this acquisition as a business combination under the acquisition method of accounting in accordance with ASC 805, *Business Combinations*. The purchase price exceeded the preliminarily-determined fair value amounts of the acquired net assets and, accordingly, $38.5 million was allocated to goodwill, of which $32.4 million was allocated to our refined products segment and $6.1 million was allocated to our crude oil segment. Additionally, related to this transaction, during October 2010, we acquired certain crude oil tank bottoms at a fair value of approximately $53.0 million. These assets have improved our connectivity with existing markets as well as expanded our crude oil logistics infrastructure. We have leased a majority of the crude oil storage included in this acquisition to BP for an intermediate period.

The purchase price and assessment of the fair value of the assets acquired and liabilities assumed were as follows (in thousands):

Purchase price	$ 291,292
Fair value of assets acquired (liabilities assumed):	
Property, plant and equipment	$ 249,381
Other current assets	2,877
Goodwill	38,496
Other intangibles	3,898
Environmental liabilities	(375)
Other current liabilities	(2,985)
Total	$ 291,292

Pro Forma Information

The following summarized pro forma consolidated income statement information assumes that the acquisition of business in 2010 referred to above occurred as of January 1, 2010. These pro forma results are for comparative purposes only and may not be indicative of the results that would have occurred had these acquisitions been completed on January 1, 2010 or the results that will be attained in the future. The amounts presented below are in thousands:

	Year Ended December 31, 2010		
	As Reported	Pro Forma Adjustments	Pro Forma
Revenues	$ 1,557,447	$ 36,483	$ 1,593,930
Net income	$ 311,580	$ 15,101	$ 326,681

Significant pro forma adjustments include historical results of the acquired assets and our calculation of general and administrative ("G&A") expense, depreciation expense and interest expense on borrowings necessary to finance the acquisition. Acquisition and start-up costs related to the assets acquired from BP were $0.6 million in 2010.

5. Inventory

Inventory at December 31, 2011 and 2012 was as follows (in thousands):

	2011	2012
Refined petroleum products	$ 127,999	$ 88,630
Liquefied petroleum gases	55,490	45,657
Transmix	60,251	63,026
Crude oil	8,065	17,443
Additives	7,055	7,132
Total inventory	$ 258,860	$ 221,888

During 2012, in conjunction with our Crane-to-Houston pipeline reversal project, we discontinued our linefill management and product marketing activities on this section of our system. The associated linefill products we held title to were either sold or transferred to our other pipelines to fulfill product shortage positions on those systems. The decrease in the inventory balance between December 31, 2011 and 2012 was primarily attributable to these product sales and transfers.

6. Product Sales Revenues

The amounts reported as product sales revenues on our consolidated statements of income include revenues 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 petroleum 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 12 - *Derivative Financial Instruments* for further disclosures regarding our NYMEX contracts.

For the years ended December 31, 2010, 2011 and 2012, product sales revenues included the following (in thousands):

	Year Ended December 31,		
	2010	2011	2012
Physical sale of petroleum products	$ 784,839	$ 870,007	$ 833,581
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 petroleum products blending and fractionation activities(1)	(10,751)	(4,330)	(30,270)
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)	(11,212)	(11,149)	(3,940)
Other	214	—	11
Total NYMEX contract adjustments	(21,749)	(15,479)	(34,199)
Total product sales revenues	$ 763,090	$ 854,528	$ 799,382

(1) The associated petroleum 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.

7. Property, Plant and Equipment

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

	December 31,		Estimated Depreciable Lives
	2011	2012	
Construction work-in-progress	$ 100,441	$ 247,571	
Land and rights-of-way	74,509	83,014	
Carrier property	1,915,688	1,835,265	6 – 59 years
Buildings	36,152	37,672	20 – 45 years
Storage tanks	958,112	975,277	10 – 40 years
Pipeline and station equipment	296,329	479,531	3 – 59 years
Processing equipment	602,113	645,140	3 – 56 years
Other	97,140	105,080	1 – 48 years
Total	$ 4,080,484	$ 4,408,550	

Carrier property is defined as pipeline assets regulated by the FERC. Other includes total interest capitalized through December 31, 2011 and 2012 of $25.0 million and $24.3 million, respectively. Depreciation expense for the years ended December 31, 2010, 2011 and 2012 was $107.3 million, $118.9 million and $126.7 million, respectively.

8. Major Customers and Concentration of Risks

Major Customers. The percentage of revenue derived by customers that accounted for 10% or more of consolidated total revenues is provided in the table below. No other customer accounted for more than 10% of our consolidated total revenues for 2010, 2011 or 2012. The majority of the revenues from Customers A and B resulted from sales to those customers 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. In general, accounts receivable from these customers are due within three days of sale. We believe that, in the event Customer A and B were unable or unwilling to do so, other companies would purchase the refined products we have for sale.

	Year Ended December 31,		
	2010	2011	2012
Customer A	11%	21%	14%
Customer B	13%	8%	7%
Total	24%	29%	21%

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 revenues from activities conducted in the central U.S. We generally secure transportation and storage revenues 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, 2012, we had 1,339 employees. At December 31, 2012, the labor force of 768 employees assigned to our refined products segment was concentrated in the central U.S. Approximately 29% 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, 2012, the labor force of 26 employees assigned to our crude oil segment was concentrated in the central U.S. and none of these employee were covered by a collective bargaining agreement. The labor force of 175 employees assigned to our marine storage segment at December 31, 2012 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, 2013.

9. 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, 2011 and 2012 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2011	2012	2011	2012
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 71,946	$ 113,914	$ 18,910	$ 23,786
Service cost	9,628	12,222	430	396
Interest cost	4,343	4,862	999	821
Plan participants' contributions	—	—	185	221
Actuarial loss	30,561	15,975	3,950	4,751
Benefits paid	(2,368)	(4,270)	(688)	(760)
Plan amendment	—	—	—	(16,020)
Settlement	(196)	—	—	—
Benefit obligation at end of year	113,914	142,703	23,786	13,195
Change in plan assets:				
Fair value of plan assets at beginning of year	61,418	70,052	—	—
Employer contributions	9,389	13,336	503	539
Plan participants' contributions	—	—	185	221
Actual return on plan assets	1,809	7,988	—	—
Benefits paid	(2,368)	(4,270)	(688)	(760)
Settlement	(196)	—	—	—
Fair value of plan assets at end of year	70,052	87,106	—	—
Funded status at end of year	$ (43,862)	$ (55,597)	$ (23,786)	$ (13,195)
Accumulated benefit obligation	$ 79,659	$ 101,233		

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.

The 2011 and 2012 actuarial losses of $30.6 million and $16.0 million, respectively, for our pension plans is due primarily to the impact of decreases in the discount rate used to calculate the benefit obligation.

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.

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

	Pension Benefits		Other Postretirement Benefits	
	2011	2012	2011	2012
Amounts recognized in consolidated balance sheet:				
Current accrued benefit cost	$ —	$ —	$ (568)	$ (658)
Long-term pension and benefit cost	(43,862)	(55,597)	(23,218)	(12,537)
	(43,862)	(55,597)	(23,786)	(13,195)
Accumulated other comprehensive loss:				
Net actuarial loss	42,451	51,899	7,688	11,418
Prior service cost (credit)	647	340	(424)	(14,473)
	43,098	52,239	7,264	(3,055)
Net amount recognized in consolidated balance sheet	$ (764)	$ (3,358)	$ (16,522)	$ (16,250)

Net periodic benefit expense for the years ended December 31, 2010, 2011 and 2012 were as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2010	2011	2012	2010	2011	2012
Components of net periodic pension and postretirement benefit expense:						
Service cost	$ 6,720	$ 9,628	$ 12,222	$ 319	$ 430	$ 396
Interest cost	3,341	4,343	4,862	992	999	821
Expected return on plan assets	(3,552)	(4,357)	(5,066)	—	—	—
Amortization of prior service cost (credit)	307	307	307	(851)	(851)	(1,971)
Amortization of actuarial loss	517	1,424	3,605	133	167	1,021
Settlement cost	—	70	—	—	—	—
Net periodic expense	$ 7,333	$ 11,415	$ 15,930	$ 593	$ 745	$ 267

Other changes in plan assets and benefit obligations recognized in other comprehensive loss during 2011 and 2012 were as follows (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2011	2012	2011	2012
Other changes in plan assets and benefit obligations recognized in other comprehensive loss:				
Net actuarial loss	$ 33,108	$ 13,053	$ 3,950	$ 4,751
Plan amendment	—	—	—	(16,020)
Amortization of actuarial loss	(1,424)	(3,605)	(167)	(1,021)
Amortization of prior service credit (cost)	(307)	(307)	851	1,971
Recognition of settlement cost	(70)	—	—	—
Total recognized in other comprehensive loss	31,307	9,141	4,634	(10,319)
Net periodic expense	11,415	15,930	745	267
Total recognized in net periodic benefit cost and other comprehensive loss	$ 42,722	$ 25,071	$ 5,379	$ (10,052)

We match our employees' qualifying contributions to our defined contribution plan, resulting in expense to us. Expenses related to the defined contribution plan were $5.9 million, $6.2 million and $6.5 million in 2010, 2011 and 2012, 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 2013 are $4.1 million and $0.3 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 2013 are $1.2 million and $(3.7) million, respectively.

The weighted-average rate assumptions used to determine benefit obligations as of December 31, 2011 and 2012 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2011	2012	2011	2012
Discount rate—Salaried plan	4.39%	4.00%	n/a	n/a
Discount rate—USW plan	4.00%	3.39%	n/a	n/a
Discount rate—IUOE plan	4.37%	3.99%	n/a	n/a
Discount rate—Other Postretirement Benefits	n/a	n/a	4.38%	3.58%
Rate of compensation increase—Salaried plan	5.00%	5.00%	n/a	n/a
Rate of compensation increase—USW plan	4.50%	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, 2010, 2011 and 2012 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2010	2011	2012	2010	2011	2012
Discount rate—Salaried plan	5.79%	5.54%	4.39%	n/a	n/a	n/a
Discount rate—USW plan	5.72%	5.07%	4.00%	n/a	n/a	n/a
Discount rate—IUOE plan	5.67%	5.52%	4.37%	n/a	n/a	n/a
Discount rate—Other Postretirement Benefits	n/a	n/a	n/a	5.97%	5.56%	3.75%
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%	4.50%	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%	3.25%	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.

The annual assumed rate of increase in the health care cost trend rate for 2013 is 7.5% decreasing systematically to 4.7% by 2100 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, 2012, 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	$ 138	$ 110
Change in postretirement benefit obligation	$ 2,441	$ 1,942

The fair value of the pension plan assets at December 31, 2011 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	$ 1,342	$ 1,342	$ —	$ —
Mid-cap fund	1,343	1,343	—	—
Large-cap fund	10,477	10,477	—	—
International equity fund	5,642	5,642	—	—
Fixed Income Securities[(a)]:				
Short-term bond funds	2,751	2,751	—	—
Intermediate-term bond funds	10,168	10,168	—	—
Long-term investment grade bond fund	31,474	31,474	—	—
Other:				
Short-term investment fund	6,455	6,455	—	—
Group annuity contract	400	—	—	400
Fair value of plan assets	$ 70,052	$ 69,652	$ —	$ 400

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

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 fund	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.

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, 2011 and 2012 were as follows (in thousands):

	2011	2012
Beginning balance	$ 432	$ 400
Actual return on plan assets:		
Relating to assets still held at the reporting date	31	16
Purchases, issuances, sales and settlements:		
Settlements	(63)	(58)
Ending balance	$ 400	$ 358

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 Morgan Stanley Country Index ("MSCI") US Small Cap 1750 Index
Mid-cap fund	Seeks to track performance of the MSCI US Mid Cap 450 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 80% of assets in international equities
Fixed Income Securities:	
Short-term bond fund	Seeks current income with limited price volatility through investment in primarily high quality corporate bonds
Intermediate-term bond funds	Seeks to track performance of bond indexes representing fixed income securities having maturities greater than one year
Long-term investment grade bond fund	Seeks high and sustainable current income through investment in long-term high grade bonds
Other:	
Short-term investment fund	Invests 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, 2011 and 2012 were as follows:

	2011		2012	
	Actual[(a)]	Target	Actual[(a)]	Target
Equity securities	27%	30%	28%	30%
Debt securities	64%	67%	69%	67%
Other	9%	3%	3%	3%

(a) Cash contributions of $9.4 million and $13.3 million were made to the pension plans during 2011 and 2012, respectively. Amounts contributed in 2011 and 2012 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, 2011 and 2012 scheduled for investment in accordance with the target. Excluding these uninvested cash amounts, the actual allocation percentages at December 31, 2011 would have been 30% equity securities and 70% debt securities and at December 31, 2012, would have been 29% equity securities and 71% debt securities. In 2013, we will invest these uninvested cash amounts to bring the total asset allocation in line with the target allocation.

As of December 31, 2012, the benefit amounts we expect to pay through December 31, 2022 were as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2013	$ 4,590	$ 659
2014	$ 5,446	$ 663
2015	$ 5,053	$ 710
2016	$ 5,923	$ 673
2017	$ 8,662	$ 726
2018 through 2022	$ 50,959	$ 4,369

Contributions estimated to be paid into the plans in 2013 are $16.0 million and $0.7 million for the pension and other postretirement benefit plans, respectively.

10. Related Party Transactions

We own a 50% interest in Osage and receive a management fee for its operation. We received operating fees from Osage of $0.8 million each year in 2010, 2011 and 2012. We reported these fees as affiliate management fee revenue on our consolidated statements of income.

We own a 50% interest in Texas Frontera, which has constructed 0.8 million barrels of refined products storage at our Galena Park, Texas terminal. These tanks, which began operation in October 2012, are leased to an affiliate of Texas Frontera under a long-term lease agreement. Additionally, we have constructed certain infrastructure assets at our Galena Park terminal which allow for the operation of the Texas Frontera tanks. For the year ended December 31, 2012, we contributed $4.2 million to Texas Frontera, including $1.7 million which was paid in cash but subsequently reimbursed to us for constructed infrastructure assets. We received management fees from Texas Frontera of $0.2 million in 2012. We reported these fees as affiliated management fee revenue on our consolidated statements of income.

We own a 50% interest in Double Eagle, which is in the process of constructing a 140-mile pipeline that will connect to an existing pipeline segment owned by an affiliate of Double Eagle. Once completed, Double Eagle will transport condensate from the Eagle Ford shale formation to our terminal in Corpus Christi, Texas. For the year ended December 31, 2012, we contributed $39.1 million for construction funding requests from Double Eagle. We expect these assets to be fully operational by the second half of 2013.

We own a 50% interest in BridgeTex, which is in the process of constructing a 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. For the year ended December 31, 2012, we contributed $31.8 million for construction funding requests from BridgeTex. We received construction management fees from BridgeTex of $0.9 million in 2012. We reported these fees as affiliate management fee revenue on our consolidated statements of income.

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 petroleum products from subsidiaries of Targa. For the years ended December 31, 2010, 2011 and 2012, we made purchases from subsidiaries of Targa of $1.8 million, $11.7 million and $27.4 million, respectively. These purchases were made on the same terms as comparable third-party transactions. We had no amount payable to Targa at December 31, 2011 and we had $0.1 million payable at December 31, 2012.

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.

11. Debt

Debt at December 31, 2011 and 2012 was as follows (in thousands):

	December 31, 2011	December 31, 2012	Weighted-Average Interest Rate at December 31, 2012 (a)
Revolving credit facility	$ —	$ —	—%
$250.0 million of 6.45% Notes due 2014	249,844	249,905	6.3%
$250.0 million of 5.65% Notes due 2016	252,037	251,609	5.7%
$250.0 million of 6.40% Notes due 2018	263,477	261,411	5.3%
$550.0 million of 6.55% Notes due 2019	578,521	575,065	5.7%
$550.0 million of 4.25% Notes due 2021	558,932	558,088	4.0%
$250.0 million of 6.40% Notes due 2037	248,964	248,981	6.4%
$250.0 million of 4.20% Notes due 2042	—	248,349	4.2%
Total debt	$ 2,151,775	$ 2,393,408	5.3%

(a) Weighted-average interest rate includes the impact of interest rate swaps, 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 12—*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, 2011 and 2012 was $2.1 billion and $2.4 billion, respectively. The difference between the face value and carrying value of the debt outstanding is the unamortized portion of various fair value hedges and the unamortized discounts and premiums on debt issuances. Note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives of the associated note. At December 31, 2012, maturities of our debt were as follows: $0 in 2013; $250.0 million in 2014; $0 in 2015; $250.0 million in 2016; $0 in 2017; and $1.9 billion thereafter.

2012 Debt Offering

In November 2012,we issued $250.0 million of 4.20% notes due December 1, 2042 in an underwritten public offering. The notes were issued for the discounted price of 99.3% of par. We have used or intend to use the net proceeds from this offering of approximately $245.8 million, after underwriting discounts and offering expenses, for general partnership purposes, including capital expenditures and investments in interest-bearing securities or accounts.

Other Debt

Revolving Credit Facility. The total borrowing capacity under our revolving credit facility, which matures in October 2016, is $800.0 million. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.875% to 1.75% based on our credit ratings and amounts outstanding under the facility. Additionally, an unused commitment fee is assessed at a rate from 0.125% to 0.3%, depending on our credit ratings, which was 0.2% at December 31, 2012. Borrowings under this facility are used for general purposes, including capital expenditures. As of December 31, 2012, 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. The terms of our revolving credit facility exclude the financial impact of unrealized gains and losses of derivative agreements from the calculation of consolidated debt to EBITDA. We were in compliance with these covenants as of and during the year ended December 31, 2012.

During the years ending December 31, 2010, 2011 and 2012, total cash payments for interest on all indebtedness, excluding the impact of related interest rate swap agreements, were $101.3 million, $111.7 million and $123.3 million, respectively.

12. Derivative Financial Instruments

Commodity Derivatives

Our petroleum products blending activities produce gasoline products, and we can estimate the timing and quantities of sales of these products. We use a combination of forward purchase and sales 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 blending activities that we choose to hedge.

We account for the forward purchase and sales contracts we use in our 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, 2012, we had commitments under these forward purchase and sale contracts as follows (in millions):

	Value	Barrels
Forward purchase contracts	$ 20.3	0.2
Forward sale contracts	$ 60.0	0.5

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

Hedge Type	Hedge Purpose	Accounting Treatment
	Qualifies for Hedge Accounting Treatment	
Cash Flow Hedge	To hedge the variability in cash flows related to a forecasted transaction.	The effective portion of changes in the 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.

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. Changes in the fair value of these agreements are recognized currently in earnings as adjustments to product purchases.

The table below sets forth the volume of our open NYMEX contracts and butane futures agreements as of December 31, 2012.

Type of Contract/Accounting Methodology	Product Represented by the Contract and Associated Barrels	Maturity Dates
NYMEX - Cash Flow Hedges	0.2 million barrels of refined petroleum products	Between January and March 2013
NYMEX - Fair Value Hedges	0.7 million barrels of crude oil	Between April and November 2013
NYMEX - Economic Hedges	1.6 million barrels of refined petroleum products and crude oil	Between January and April 2013
Butane Futures Agreements - Economic Hedges	0.2 million barrels of butane	Between January and April 2013

At December 31, 2012, we had made margin deposits of $18.3 million for our NYMEX contracts, which were recorded as a current asset under energy commodity derivatives deposits on our consolidated balance sheet. 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 with each of our counterparties; 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.

Interest Rate Derivatives

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.

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 (excluding $0.2 million of accrued interest), which was recorded as an adjustment to long-term debt that is being amortized over the remaining life of the notes into interest expense.

Interest Rate Derivatives Activity During 2010. In June and August 2009, we entered into $150.0 million and $100.0 million, respectively, of interest rate swap agreements to hedge against changes in the fair value of a portion of the $550.0 million of 6.55% notes due 2019, and we accounted for these agreements as fair value hedges. In May 2010, we terminated and settled $150.0 million of the swaps and received $9.6 million (excluding $1.8 million of accrued interest), which was recorded as an adjustment to long-term debt that is being amortized over the remaining life of the 6.55% notes. In June 2010, we terminated and settled the remaining $100.0 million of swaps and received $6.6 million (excluding $1.5 million of accrued interest), which was recorded as an adjustment to long-term debt that is being amortized over the remaining life of the 6.55% notes into interest expense.

See *Comprehensive Income* in Note 2—*Summary of Significant Accounting Policies* for details of derivative activity included in AOCL for the years ended December 31, 2010, 2011 and 2012. As of December 31, 2012, the net gain estimated to be classified to interest expense and product sales revenues over the next twelve months from AOCL is approximately $0.2 million each.

The following table provides a summary of the effect on our consolidated statements of income for the year ended December 31, 2011 of derivatives accounted for under ASC 815-25, *Derivatives and Hedging—Fair Value Hedges* (in thousands). All of the interest rate swap agreements we entered into during 2012 were designated as cash flow hedges (see discussion of cash flow hedges further below).

		Year Ended December 31, 2011	
Derivative Instrument	**Location of Gain Recognized on Derivative**	**Amount of Gain Recognized on Derivative**	**Amount of Interest Expense Recognized on Fixed-Rate Debt (Related Hedged Item)**
Interest rate swap agreements	Interest expense	$1,275	$7,556

At December 31, 2011 and 2012, we had open NYMEX contracts on 0.7 million barrels of crude oil that were designated as fair value hedges. During 2011, because there was no ineffectiveness recognized on these hedges, the cumulative losses of $6.4 million from the agreements were fully offset by a cumulative increase of $6.4 million to tank bottom inventory; therefore, there was no net impact from these agreements on income/expense. 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.

The following is a summary of the effect on our consolidated statements of income for the years ended December 31, 2011 and 2012 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 6 - *Product Sales Revenues* for further details regarding the impact of our NYMEX agreements on product sales.

	Year Ended December 31, 2011		
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 swap agreements	$ —	Interest expense	$ 164
NYMEX commodity contracts	7,739	Product sales revenues	7,739
Total cash flow hedges	$ 7,739	Total	$ 7,903

	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 swap agreements	$ 10,977	Interest expense	$ 164
NYMEX commodity contracts	2,912	Product sales revenues	2,760
Total cash flow hedges	$ 13,889	Total	$ 2,924

There was no ineffectiveness recognized on the financial instruments disclosed in the above tables during the years ended December 31, 2011 and 2012.

The following table provides a summary of the effect on our consolidated statements of income for the years ended December 31, 2011 and 2012 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	2011	2012
NYMEX commodity contracts	Product sales revenues	$ (23,218)	$ (36,959)
NYMEX commodity contracts	Operating expenses	(331)	(2,055)
Butane futures agreements	Product purchases	(14)	1,203
	Total	$ (23,563)	$ (37,811)

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, 2011 and 2012 (in thousands):

	December 31, 2011			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts	$ 31	Energy commodity derivatives contracts	$ —
NYMEX commodity contracts	Other noncurrent assets	—	Other noncurrent liabilities	6,457
		$ 31		$ 6,457

	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	$ 473	Energy commodity derivatives contracts	$ 207

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, 2011 and 2012 (in thousands):

	December 31, 2011			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts	$ 6,403	Energy commodity derivatives contracts	$ 1,514
Butane futures agreements	Energy commodity derivatives contracts	28	Energy commodity derivatives contracts	34
	Total	$ 6,431	Total	$ 1,548

	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	$ 227	Energy commodity derivatives contracts	$ 8,954
Butane futures agreements	Energy commodity derivatives contracts	1,350	Energy commodity derivatives contracts	227
	Total	$ 1,577	Total	$ 9,181

13. Leases

Leases—Lessee. We lease land, office buildings and terminal equipment at various locations to conduct our business operations. 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 $4.0 million, $4.6 million and $4.8 million for the years ended December 31, 2010, 2011 and 2012, respectively. Future minimum annual rentals under non-cancellable operating leases as of December 31, 2012, were as follows (in millions):

2013	$ 3.8
2014	3.6
2015	3.0
2016	2.8
2017	2.7
Thereafter	18.4
Total	$ 34.3

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, 2012, were as follows (in millions):

2013	$ 205.3
2014	200.0
2015	167.7
2016	115.9
2017	83.4
Thereafter	200.7
Total	$ 973.0

14. 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, 2012 total 2.4 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. 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 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 forfeited during 2012.

	Equity Method							
	Performance-Based Awards		Retention Awards		Liability Method Performance-Based		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 - 1/1/2012	548,024	$ 22.93	120,760	$ 20.55	137,008	$ 33.65	805,792	$ 24.39
Units granted during 2012	214,232	$ 33.57	7,016	$ 30.54	53,558	$ 33.57	274,806	$ 33.50
Units vested during 2012	(302,464)	$ 17.54	(61,990)	$ 17.77	(75,616)	$ 43.19	(440,070)	$ 21.98
Units forfeited during 2012	(15,702)	$ 25.59	(6,984)	$ 21.02	(3,925)	$ 43.19	(26,611)	$ 26.99
Non-vested units - 12/31/12	444,090	$ 31.24	58,802	$ 24.60	111,025	$ 43.19	613,917	$ 32.77

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:						
2011 Awards	302,022	14,043	215,984	503,963	12/31/2013	$ 5.2
2012 Awards	267,322	12,689	127,317	381,950	12/31/2014	9.0
Retention Awards:						
2013 Vesting Date	1,764	106	—	1,658	12/31/2013	— [(b)]
2014 Vesting Date	63,368	6,654	—	56,714	12/31/2014	0.9
Total	634,476	33,492	343,301	944,285		$ 15.1

(a) Unrecognized compensation expense will be recognized over the remaining vesting period of the awards.
(b) Less than $0.1 million.

Weighted-Average Grant Date Fair Values

The weighted-average grant-date fair value of award grants issued during 2010, 2011 and 2012 were as follows:

	Equity Method				Liability Method Performance-Based	
	Performance-Based Awards		Retention 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 2010	326,260	$ 17.53	85,958	$ 17.47	81,566	$ 25.43
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

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, 2012.

Grant Date	Vested Limited Partner Units	Vesting Date	Fair Value of Unit Awards on Vesting Date (in millions)*	Intrinsic Value of Unit Awards on Vesting Date (in millions)
2008 Awards	767,792	12/31/2010	$ 13.0	$ 21.7
2009 Awards	1,100,276	12/31/2011	$ 16.5	$ 37.9
2010 Awards	751,237	12/31/2012	$ 17.1	$ 32.5

* 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)
2007 Awards	January 2010	280,634	$ 3.4	$ 0.5	$ 3.9
2008 Awards	January 2011	505,492	$ 7.4	$ 0.9	$ 8.3
2009 Awards	January 2012	722,766	$ 13.0	$ 1.3	$ 14.3

Compensation Expense Summary

Equity-based incentive compensation expense excluding amounts for directors (discussed below) for 2010, 2011 and 2012 was as follows (in thousands):

	Year Ended December 31, 2010			Year Ended December 31, 2011			Year Ended December 31, 2012		
	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total
2007 awards	$ —	$ 6	$ 6	$ —	$ —	$ —	$ —	$ —	$ —
2008 awards	6,763	3,802	10,565	—	—	—	—	—	—
2009 awards	2,800	2,189	4,989	4,418	4,264	8,682	—	—	—
2010 awards	1,842	669	2,511	3,100	1,562	4,662	4,937	3,723	8,660
2011 awards	—	—	—	2,839	841	3,680	5,062	2,094	7,156
2012 awards	—	—	—	—	—	—	3,426	1,101	4,527
Retention awards	828	—	828	686	—	686	693	—	693
Total	$ 12,233	$ 6,666	$ 18,899	$ 11,043	$ 6,667	$ 17,710	$ 14,118	$ 6,918	$ 21,036
Allocation of LTIP expense on our consolidated statements of income:									
G&A expense			$ 16,474			$ 16,024			$ 18,587
Operating expense			2,425			1,686			2,449
Total			$ 18,899			$ 17,710			$ 21,036

Director Compensation Expense

Pursuant to the 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,		
	2010	2011	2012
Phantom units earned	30,002	25,236	25,017
(in thousands)			
Compensation - phantom unit expense	$ 449	$ 446	$ 523
Distribution equivalents	100	139	195
Changes in market value of phantom units	460	568	973
Total phantom units earned	1,009	1,153	1,691
Compensation paid in cash	306	292	345
Compensation paid in our limited partner units	140	140	170
Total director compensation	1,455	1,585	2,206
Distribution equivalents charged to partners' capital	(100)	(139)	(195)
Total director compensation expense	$ 1,355	$ 1,446	$ 2,011

15. 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 revenues from affiliates and external customers, operating expenses, product purchases and equity earnings. 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, 2010				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
			(in thousands)		
Transportation and terminals revenues	$ 631,872	$ 22,051	$ 139,676	$ —	$ 793,599
Product sales revenues	759,062	214	3,814	—	763,090
Affiliate management fee revenue	—	758	—	—	758
Total revenues	1,390,934	23,023	143,490	—	1,557,447
Operating expenses	232,565	238	52,418	(3,009)	282,212
Product purchases	667,079	—	1,506	—	668,585
Equity earnings	—	(5,732)	—	—	(5,732)
Operating margin	491,290	28,517	89,566	3,009	612,382
Depreciation and amortization expense	77,170	3,444	25,045	3,009	108,668
G&A expenses	76,955	1,491	16,870	—	95,316
Operating profit (loss)	$ 337,165	$ 23,582	$ 47,651	$ —	$ 408,398
Additions to long-lived assets	$ 242,523	$ 221,779	$ 45,183		$ 509,485
	As of December 31, 2010				
Segment assets	$ 2,658,986	$ 406,344	$ 619,974		$ 3,685,304
Corporate assets					32,596
Total assets					$ 3,717,900
Goodwill	$ 38,369	$ 12,082	2,809		$ 53,260
Investments in non-controlled entities	$ —	$ 22,934	794		$ 23,728

	Year Ended December 31, 2011				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
			(in thousands)		
Transportation and terminals revenues	$ 680,235	$ 61,205	$ 151,929	$ —	$ 893,369
Product sales revenues	848,902	591	5,035	—	854,528
Affiliate management fee revenue	—	770	—	—	770
Total revenues	1,529,137	62,566	156,964	—	1,748,667
Operating expenses	250,794	(4,898)	63,438	(2,919)	306,415
Product purchases	704,313	—	1,957	—	706,270
Equity earnings	—	(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

	Year Ended December 31, 2012				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
			(in thousands)		
Transportation and terminals revenues	$ 723,835	$ 92,288	$ 154,621	$ —	$ 970,744
Product sales revenues	790,116	—	9,266	—	799,382
Affiliate management fee revenue	—	1,734	214	—	1,948
Total revenues	1,513,951	94,022	164,101	—	1,772,074
Operating expenses	267,694	5,229	58,486	(2,955)	328,454
Product purchases	653,429	—	3,679	—	657,108
Equity earnings	—	(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

The increase in corporate assets from December 31, 2010 to December 31, 2012 was primarily due to the cash and cash equivalents on hand at December 31, 2012.

16. 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 EPA is required to collect the fees if a state does not administer and enforce CAA 185. The Houston-Galveston region was initially determined to be a severe nonattainment area that did not meet its 2007 attainment deadline and, as such, would be subject to CAA 185. The Texas Commission on Environmental Quality ("TCEQ") is currently considering a "Failure to Attain Rule" to implement the requirements of CAA 185. The draft Failure to Attain Rule is anticipated to be adopted in 2013 and is expected to provide for the collection of an annual failure to attain fee for excess emissions. We have certain facilities in the Houston area that will be subject to the TCEQ's Failure to Attain Rule.

Management believes the most likely scenario is that we will be assessed fees for excess emissions at our Houston area facilities and our estimate of the possible range of loss associated with this matter is from zero to $14.3 million. As of December 31, 2012, we have accrued $10.9 million as a long-term environmental liability related to this matter. Management believes that recent indications with regard to this matter by the TCEQ and the EPA have been favorable to us. The final Failure to Attain Rule is expected to be published in 2013; therefore, it is likely that our estimate of this loss will change in the near term.

Osage Complaint

In June 2012, HollyFrontier filed a complaint with the FERC alleging that Osage has been over-earning on its rates for transportation on Osage's crude oil pipeline system from Cushing, Oklahoma to El Dorado, Kansas. We own 50% of Osage and serve as its operator. Osage and HollyFrontier have agreed to settle this matter, subject to FERC approval. The settlement agreement includes a one-time cash payment for reparations, reduced future tariff rates and other concessions. This settlement will not have a material impact on our results of operations, financial position or cash flows.

Potential Responsible Party in a Pasadena, Texas Superfund Site

In December 2012, we received a notice from the EPA that we may have potential liability at the U.S. Oil Recovery Superfund Site in Pasadena, Texas as a potential responsible party under Section 107(a) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended. 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. Due to the timing of the EPA's notice, we are unable at this point, to reasonably estimate the amount of our potential liability, if any, related to this matter.

Sale of Claim Against MF Global Inc.

In October 2011, MF Global Holdings Ltd., the parent of MF Global Inc. ("MF Global"), filed for bankruptcy protection under Chapter 11 of the U.S. bankruptcy laws, and a trustee was appointed to oversee the liquidation of MF Global under the Securities Investor Protection Act. At that time, MF Global served as our sole clearing agent for NYMEX futures contracts. We transferred our existing trading positions at MF Global to a new clearing agent in November 2011. As of the date of transfer of our account, MF Global owed us $29.4 million. We subsequently received $23.6 million as partial payment of the amount owed to us. In December 2012, we sold our remaining claim of $5.8 million to a third party for $5.4 million. The buyer of the claim assumed the risk of ultimate collectability of the claim subject to the accuracy of typical representations and warranties from us related to the claim. We charged the $0.4 million loss we sustained from the sale of this receivable to operating expense.

Environmental Liabilities

Liabilities recognized for estimated environmental costs were $49.6 million and $48.3 million at December 31, 2011 and December 31, 2012, 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 $11.8 million, $23.1 million and $12.0 million for the years ended December 31, 2010, 2011 and 2012, respectively. The higher environmental expenses in 2011 were primarily due to the CAA 185 liability accrual (described above).

Environmental Receivables

Receivables from insurance carriers and other third parties related to environmental matters at December 31, 2011 were $7.7 million, of which $5.2 million and $2.5 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, 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. Amounts received from insurance carriers and other third parties related to environmental matters during 2010, 2011 and 2012 were $2.8 million, $0.5 million and $1.2 million, respectively.

Other

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 results of operations, financial position or cash flows.

17. Quarterly Financial Data (unaudited)

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

2011	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 442,897	$ 383,327	$ 435,510	$ 486,933
Total costs and expenses	$ 327,544	$ 256,104	$ 299,712	$ 349,173
Operating margin	$ 170,673	$ 184,611	$ 188,457	$ 199,004
Net income	$ 90,065	$ 102,999	$ 110,240	$ 110,262
Net income allocated to limited partners' interest	$ 90,128	$ 102,999	$ 110,240	$ 110,262
Basic and diluted net income per limited partner unit	$ 0.40	$ 0.46	$ 0.49	$ 0.49
2012				
Revenues	$ 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

The third quarter 2012 operating margin was negatively impacted by unrealized losses on NYMEX contracts as a result of increasing product prices in that period.

18. Fair Value Disclosures

Fair Value of Financial Instruments

We used the following methods and assumptions in estimating our fair value disclosure for financial instruments:

- *Cash and cash equivalents.* 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 paid associated with our energy commodity derivatives contracts. The carrying amount reported on our consolidated balance sheets approximates fair value as the deposits paid change daily in relation to the associated contracts.
- *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 12 - *Derivative Financial Instruments* for further disclosures regarding these contracts.
- *Long-term receivables.* 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 US treasury rates.
- *Debt.* The fair value of our publicly traded notes was based on the exchange prices of those notes at December 31, 2011 and December 31, 2012. The carrying amount of borrowings under our revolving credit facility, if any, approximates fair value due to the variable rates of that instrument.

The following table reflects the carrying amounts and fair values of our financial instruments as of December 31, 2011 and 2012 (in thousands):

	December 31, 2011		December 31, 2012	
Assets (Liabilities)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 209,620	$ 209,620	$ 328,278	$ 328,278
Energy commodity derivatives deposits (current assets)	$ 26,917	$ 26,917	$ 18,304	$ 18,304
Energy commodity derivatives contracts (current assets)	$ 4,914	$ 4,914	$ —	$ —
Energy commodity derivatives contracts (current liabilities)	$ —	$ —	$ (7,338)	$ (7,338)
Energy commodity derivatives contracts (noncurrent liabilities)	$ (6,457)	$ (6,457)	$ —	$ —
Long-term receivables	$ 2,534	$ 2,510	$ 5,135	$ 5,108
Debt	$ (2,151,775)	$ (2,389,700)	$ (2,393,408)	$ (2,721,985)

Fair Value Measurements

The following tables summarize the recurring fair value measurements of our NYMEX commodity contracts as of December 31, 2011 and December 31, 2012, based on the three levels established by ASC 820-10-50; Paragraph 2, *Fair Value Measurements and Disclosures-Overall-Disclosure* (in thousands):

		Fair Value Measurements as of December 31, 2011 using:		
Assets (Liabilities)	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Cash equivalents	$ 172,164	$ 172,164	$ —	$ —
Energy commodity derivatives contracts (current assets)	$ 4,914	$ 4,914	$ —	$ —
Energy commodity derivatives contracts (noncurrent liabilities)	$ (6,457)	$ (6,457)	$ —	$ —
Long-term receivables	$ 2,510	$ —	$ —	$ 2,510
Debt	$ (2,389,700)	$ (2,389,700)	$ —	$ —

		Fair Value Measurements as of December 31, 2012 using:		
Assets (Liabilities)	**Total**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Cash equivalents	$ 319,716	$ 319,716	$ —	$ —
Energy commodity derivatives contracts (current liabilities)	$ (7,338)	$ (7,338)	$ —	$ —
Long-term receivables	$ 5,108	$ —	$ —	$ 5,108
Debt	$ (2,721,985)	$ (2,721,985)	$ —	$ —

19. Distributions

Distributions we paid during 2010, 2011 and 2012 were as follows (in thousands, except per unit amount):

Payment Date	Per Unit Cash Distribution Amount	Total Cash Distribution
2/12/2010	$ 0.35500	$ 75,779
5/14/2010	0.36000	76,847
8/13/2010	0.36625	82,393
11/12/2010	0.37250	83,798
Total	$ 1.45375	$ 318,817
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

20. Owners' Equity

The following table details the changes in the number of our limited partner units outstanding from January 1, 2010 through December 31, 2012.

Limited partner units outstanding on January 1, 2010	**213,175,644**
01/10—Settlement of 2007 award grants	280,634
01/10—Other[(a)]	6,420
07/10—Issuance of limited partner units	11,500,000
Limited partner units outstanding on December 31, 2010	**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**

(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.

21. Subsequent Events

Recognizable events

No recognizable events have occurred subsequent to December 31, 2012.

Non-recognizable events

On February 1, 2013, the compensation committee approved 224,349 phantom unit award grants pursuant to our long-term incentive plan. These award grants are performance-based and have a three-year vesting period that will end on December 31, 2015.

On January 31, 2013, we issued 478,566 limited partner units, of which 476,682 were issued to settle unit award grants to certain employees that vested on December 31, 2012 and 1,884 were issued to settle the equity-based retainer paid to one of the directors of our general partner.

On February 14, 2013, we paid cash distributions of $0.50 per unit on our outstanding limited partner units to unitholders of record at the close of business on February 6, 2013. The total distributions paid were $113.3 million.

On February 22, 2013, we announced an agreement to acquire approximately 800 miles of refined products pipeline from Plains All American Pipeline, L.P. for $190 million. Subject to regulatory approvals, we expect the acquisition to close during the second quarter of 2013. We expect to fund the acquisition with cash on hand and, if necessary, with borrowings under our revolving credit facility.