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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2009

OR

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

Commission file number 1-16335

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The aggregate market value of the registrant's voting and non-voting limited partner units held by non-affiliates computed by reference to the price at which the limited partner units were last sold as of June 30, 2009 was $2,317,392,854.

As of February 23, 2010, there were 106,731,349 limited partner units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement being prepared for the solicitation of proxies in connection with the 2010 Annual Meeting of Limited Partners are incorporated by reference in Part III of this Form 10-K.

MAGELLAN MIDSTREAM PARTNERS, L.P.

FORM 10-K

PART I

ITEM 1. *Business*

(a) General Development of Business

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

Simplification

In March 2009, we and our general partner and Magellan Midstream Holdings, L.P. (“MGG”), the former owner of our general partner, and Magellan Midstream Holdings GP, LLC (“MGG GP”), MGG’s general partner, entered into an Agreement Relating to Simplification of Capital Structure (the Simplification Agreement and the steps completed pursuant thereto are referred to herein as “the simplification”). Pursuant to the simplification, which was approved by both our and MGG’s unitholders on September 25, 2009, we amended and restated our existing partnership agreement to provide for the transformation of the incentive distribution rights and approximate 2% general partner interest owned by MMP GP into limited partner units representing limited partner interests in us (“new limited partner units”) and a non-economic general partner interest in us (the “transformation”). Once the transformation was completed, MMP GP distributed the new limited partner units that it received in the transformation to MGG (the “unit distribution”). Once the unit distribution was completed, pursuant to a Contribution and Assumption Agreement: (i) MGG contributed 100% of its member interests in MGG GP, its general partner, to MMP GP; (ii) MGG contributed 100% of its member interests in MMP GP to us; (iii) MGG contributed to us all of its cash and assets, other than the new limited partner units it received in the unit distribution; and (iv) we assumed all of MGG’s liabilities (collectively, the “contributions”). Once the contributions were completed, MGG distributed the new limited partner units it received in the unit distribution to its unitholders (the “redistribution”) and MGG was dissolved. The transformation of the general partner interest and incentive distribution rights into the new limited partner units occurred on September 28, 2009.

MMP GP, our general partner, continues to manage us following the simplification and our management team has remained unchanged. Additionally, three of the four independent members of MGG’s general partner’s board of directors joined our general partner’s board of directors. The other independent member of MGG’s general partner’s board of directors, Patrick C. Eilers, was already serving as an independent member of our general partner’s board of directors.

Longhorn Pipeline Acquisition

In July 2009, we acquired substantially all of the assets of Longhorn Partners Pipeline, L.P. (which is referred to herein as the “Longhorn acquisition”) for $252.3 million plus the fair market value of the linefill of $86.1 million. The Longhorn acquisition primarily included an approximate 700-mile common carrier pipeline system that transports refined petroleum products from Houston to El Paso, Texas. The acquisition also included a terminal in El Paso that serves local petroleum products demand and distributes product to connecting third-party pipelines for ultimate delivery to markets in Arizona and New Mexico. We are in the process of connecting this pipeline system to our existing East Houston, Texas terminal to provide additional supply options for customers to transport petroleum products to southwestern markets. Further, we will complete construction of 400,000 barrels of storage that is currently underway at the El Paso terminal.

(b) Financial Information About Segments

See Part II—Financial Statements and Supplementary Data.

(c) Narrative Description of Business

We are principally engaged in the transportation, storage and distribution of refined petroleum products. As of December 31, 2009, our asset portfolio consists of:

- a 9,500-mile petroleum products pipeline system, including 51 petroleum products terminals serving the mid-continent region of the United States, which we refer to as our petroleum products pipeline system;
- seven petroleum products terminal facilities located along the United States Gulf and East Coasts, which we refer to as our marine terminals, and 27 petroleum products terminals located principally in the southeastern United States, which we refer to as our inland terminals; and
- an 1,100-mile ammonia pipeline system serving the mid-continent region of the United States.

Petroleum Products Industry Background

The United States petroleum products transportation and distribution system links oil refineries to end-users of gasoline and other petroleum products and is comprised of a network of pipelines, terminals, storage facilities, tankers, barges, railcars and trucks. For transportation of petroleum 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. Petroleum products transported, stored and distributed through our petroleum products pipeline system and petroleum products terminals include:

- *refined petroleum products,* which are the output from refineries and are primarily used as fuels by consumers. Refined petroleum products include gasoline, diesel fuel, aviation fuel, kerosene and heating oil;
- *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 petroleum 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; and
- *crude oil and condensate,* which are used as feedstocks by refineries.

In addition, we store, blend and distribute biofuels such as ethanol and biodiesel, which are increasingly required by government mandates.

The Gulf Coast region is a significant supply source for our facilities and is a major hub for petroleum refining. According to the "Annual Refinery Report for 2009" published by the Energy Information Administration ("EIA"), the Gulf Coast region accounted for approximately 44% of total U.S. daily refining capacity and 61% of U.S. refining capacity expansion from 1999 to 2008. The growth in Gulf Coast refining capacity has resulted in part from consolidation in the petroleum industry to take advantage of economies of scale from operating larger refineries.

Description of Our Businesses

PETROLEUM PRODUCTS PIPELINE SYSTEM

Our common carrier petroleum products pipeline system extends approximately 9,500 miles and covers a 13-state area, extending from the Gulf Coast refining region across Texas and through the Midwest to Colorado, North Dakota, Minnesota, Wisconsin and Illinois. Our pipeline system transports petroleum products and LPGs and includes 51 terminals. The products transported on our pipeline system are largely transportation fuels, and in 2009 were comprised of 57% gasoline, 34% distillates (which include diesel fuels and heating oil) and 9% aviation fuel and LPGs. Product shipments originate on our pipeline system from direct connections to refineries and interconnections with other interstate pipelines for transportation and ultimate distribution to retail gasoline stations, truck stops, railroads, airports and other end-users. Our petroleum products pipeline system segment accounted for 88%, 84% and 80% of our consolidated total revenues for the years ended December 31, 2007, 2008 and 2009, respectively. See Note 18—Segment Disclosures in the accompanying consolidated financial statements for financial information about our petroleum products pipeline system segment.

Our petroleum products pipeline system is dependent on the ability of refiners and marketers to meet the demand for refined petroleum products and LPGs in the markets they serve through their shipments on our pipeline system. According to December 2009 projections provided by the EIA, the demand for refined petroleum products in the primary market areas served by our petroleum products pipeline system, known as West North Central and West South Central census districts, is expected to remain relatively stable over the next 10 years, growing less than 1% annually. The total production of refined petroleum products from refineries located in West North Central districts has historically been insufficient to meet the demand for refined petroleum products. Any excess West North Central demand has been and is expected to be met largely by imports of refined petroleum products via pipelines from Gulf Coast refineries that are located in the West South Central census region, which represents the Gulf Coast region.

Our petroleum products pipeline system is well-connected to Gulf Coast refineries. In addition to our own pipeline that originates in the Gulf Coast region, we also have interconnections with third-party pipelines that originate on the Gulf Coast. These connections to Gulf Coast refineries, together with our pipeline's extensive network throughout the West North Central district and connections to the West South Central district refineries, should allow us to accommodate any demand growth or major supply shifts that may occur.

The operating statistics below reflect our petroleum products pipeline system's operations for the periods indicated:

	Year Ended December 31,		
	2007	**2008**	**2009**
Shipments (thousand barrels):			
Refined products			
Gasoline	159,807	152,703	169,873
Distillates	119,602	114,751	100,214
Aviation fuel	24,562	22,190	19,843
LPGs	3,232	6,252	5,770
Total product shipments	307,203	295,896	295,700
Capacity leases	30,114	24,665	29,821
Total shipments, including capacity leases	337,317	320,561	325,521
Daily average (thousand barrels)	924	876	892

The maximum number of barrels our petroleum products pipeline system can transport per day depends upon the operating balance achieved at a given time between various segments of our pipeline system. This balance is dependent upon the mix of petroleum products to be shipped and the demand levels at the various delivery points. We believe that we will be able to accommodate anticipated demand increases in the markets we serve through expansions or modifications of our petroleum products pipeline system, if necessary.

Operations. Our petroleum products pipeline system is the longest common carrier pipeline for refined petroleum products and LPGs in the United States. Through direct refinery connections and interconnections with other interstate pipelines, our system can access more than 40% of the refinery capacity in the continental

United States. Most of the shipments on our pipeline system are for third parties and we do not take title to those products. We do take title to products related to our petroleum products blending and fractionation activities and we own and have title to the linefill related to the pipeline acquired in the Longhorn acquisition, and we take title to the petroleum product we transport on this pipeline on our own behalf. Furthermore, under our tariffs, we are allowed to deduct from our shipper's inventory a prescribed quantity of the petroleum products our shippers transport on our pipeline to compensate us for metering inaccuracies, evaporation or other events that result in volume losses in the shipment process. To the extent we can manage our volume loss below the deducted amount, we take title to those products which we can sell, thereby reducing our operating expenses.

In 2009, our petroleum products pipeline system generated 72% of its revenue, excluding product sales revenues, from transportation tariffs on volumes shipped. These transportation 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"). Included as part of these tariffs are charges for terminalling and storage of products at 35 of our pipeline system's 51 terminals. Revenues from terminalling and storage at our other 16 terminals are at privately negotiated rates.

In 2009, our petroleum products pipeline system generated the remaining 28% of its revenues, excluding product sales revenues, from leasing pipeline and storage tank capacity to shippers and from providing product and other services such as 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. We also receive a fee for operating a 135-mile pipeline that transports crude oil from Cushing, Oklahoma to El Dorado, Kansas and has connections to National Cooperative Refining Association's refinery in McPherson, Kansas and the Frontier refinery in El Dorado, Kansas. See Note 3—Organization—Operating Segment—Petroleum Product Pipeline System in the accompanying consolidated financial statements for additional information about this pipeline system.

Product margin for the petroleum products pipeline system primarily results from our petroleum products blending and transmix fractionation activities and from linefill management and product marketing associated the Longhorn acquisition. Our petroleum products 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 specifications and by the varying quality of the product delivered to us at our pipeline origins. We typically lock in most of the margin from this blending activity by entering into either forward physical or New York Mercantile Exchange ("NYMEX") gasoline sales contracts at the time we purchase the related LPGs. We also operate two fractionators along our pipeline system that separate transmix, which is an unusable mixture of various petroleum products, back into its original components. We purchase transmix from third parties and sell the resulting separated petroleum products. We also purchase petroleum products for shipment on the pipeline we purchased as part of the Longhorn acquisition to facilitate product shipments on the pipeline. We sell these products in the El Paso, Texas wholesale markets. Prior to March 2008, we also received product margin from a third-party supply agreement. Product margin from all of these activities was $66.2 million, $114.4 million and $44.2 million for the years ended December 31, 2007, 2008, and 2009, respectively. The amount of margin we earn from these activities fluctuates with changes in petroleum prices, and we benefited significantly from the unprecedented increase in petroleum prices during 2008. Product margin is not a generally accepted accounting principle financial measure but its components, product sales revenues and product purchases, are determined in accordance with generally accepted accounting principles. 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.

We adhere to a commodity management policy that is designed to limit our financial exposure to petroleum product price movement. We accomplish this through the utilization of derivatives such as NYMEX contracts, swaps and forward purchase and sales contracts. To the extent we utilize NYMEX contracts as economic hedges, they may not qualify for hedge accounting treatment given that these contracts are for commodities delivered in the New York Harbor, while our physical commodity transactions are generally conducted in the Gulf Coast or Mid-Continent markets of the United States.

Facilities. Our petroleum products pipeline system consists of an approximate 9,500-mile pipeline with 51 terminals and includes more than 31.0 million barrels of aggregate usable storage capacity. The terminals deliver petroleum products primarily into tank trucks.

Petroleum Products Supply. Petroleum products originate from refineries, pipeline interconnection points and terminals along our pipeline system. In 2009, approximately 65% of the petroleum products transported on our petroleum products pipeline system originated from 11 direct refinery connections and 35% originated from interconnections with other pipelines or terminals.

As set forth in the table below, our system is directly connected to, and receives product from, 11 operating refineries.

Major Origins—Refineries (Listed Alphabetically)

Company	Refinery Location
Coffeyville Resources	Coffeyville, KS
ConocoPhillips	Ponca City, OK
Flint Hills Resources (Koch)	Pine Bend, MN
Frontier Oil	El Dorado, KS
Gary-Williams Energy	Wynnewood, OK
Holly Corporation	Tulsa, OK
Marathon Ashland Petroleum	St. Paul, MN
Murphy Oil USA	Superior, WI
National Cooperative Refining Association	McPherson, KS
Valero Energy	Ardmore, OK
Valero Energy	Houston, TX

Our system is also connected to multiple pipelines and terminals, including those set forth 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
Cenex	Fargo, ND	Laurel, MT refinery
ConocoPhillips	Kansas City, KS	Various Gulf Coast refineries (via Seaway/Standish Pipeline); Borger, TX refinery
Explorer	Glenpool, OK; Mt. Vernon, MO	Various Gulf Coast refineries
Mid-America (Enterprise)	El Dorado, KS	Conway, KS storage
Kinder Morgan	Pasadena and Galena Park, TX	Various Gulf Coast refineries and imports
Magellan Terminals Holdings	Galena Park, TX	Various Gulf Coast refineries and imports
NuStar Energy	El Dorado, KS; Minneapolis, MN	Various OK & KS refineries and Mandan, ND refinery
ONEOK Partners	Plattsburg, MO; Des Moines, IA; Wayne, IL	Bushton, KS storage and Chicago, IL area refineries
Sinco	East Houston, TX	Deer Park, TX refinery
West Shore	Chicago, IL	Various Chicago, IL area refineries

Customers and Contracts. We ship petroleum products for several different types of customers, including independent and integrated oil companies, wholesalers, retailers, railroads, airlines and regional farm cooperatives. End markets for these deliveries are primarily retail gasoline stations, truck stops, farm cooperatives, railroad fueling depots and military and commercial jet fuel users. Propane shippers include wholesalers and retailers who, 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 supplemental agreements with shippers that commonly result in volume and/or term commitments by shippers in exchange for reduced tariff rates or capital expansion commitments on our part. For 2009, approximately 55% of the shipments were subject to these supplemental agreements with remaining terms of up to five years. While many of these agreements do not represent guaranteed volumes, they do reflect a significant level of shipper commitment to our petroleum products pipeline system.

For the year ended December 31, 2009, our petroleum products pipeline system had approximately 60 transportation customers. The top 10 shippers included independent refining companies, integrated oil companies and farm cooperatives, and revenues attributable to these top 10 shippers for the year ended December 31, 2009 represented 40% of total revenues for our petroleum products pipeline system and 60% of revenues excluding product sales.

Product sales are primarily to trading and marketing companies. These sales agreements are generally short-term in nature.

Markets and Competition. In certain markets, barge, truck or rail provide an alternative source for transporting refined products; however, pipelines are generally the lowest-cost alternative for petroleum product 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 all pipelines is the use of exchange agreements among shippers. Under these arrangements, a shipper will agree 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 average transportation rate paid to us. We have been able to compete with these alternatives through price incentives and through long-term commercial arrangements with potential exchange partners. Nevertheless, a significant amount of exchange activity has occurred historically and is likely to continue.

Government mandates increasingly require the use of renewable fuels, particularly ethanol. Ethanol producers are responding to these mandates by significantly increasing their capacity for production of ethanol. Due to concerns regarding corrosion and product contamination, pipelines have generally not shipped ethanol and most ethanol is shipped by railroad or truck. The increased use of ethanol has and will continue to compete with shipments on our pipeline systems. However, most terminals on our pipeline system 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.

PETROLEUM PRODUCTS TERMINALS

Within our petroleum products terminals network, we operate two types of terminals: marine terminals and inland terminals. Our marine terminals are large storage and distribution facilities that have marine access and in some cases are in close proximity to large refining complexes. Our inland terminals are primarily located in the southeastern United States along third-party pipelines such as those operated by Colonial, Explorer, Plantation and TEPPCO. Our facilities receive products from pipelines and distribute them to third parties at the terminals, which in turn deliver them to end-users such as retail outlets. Because 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 petroleum products terminals segment accounted for 11%, 14% and 18% of our consolidated total revenues in 2007, 2008 and 2009, respectively. See Note 18— Segment Disclosures in the accompanying consolidated financial statements for financial information about our petroleum products terminals segment.

Marine Terminals

We own and operate seven marine terminals, including five marine terminals located along the Gulf Coast. Our marine terminals are large storage and distribution facilities, with an aggregate storage capacity of approximately 27.0 million barrels, which provide distribution, storage, blending, inventory management and additive injection services for refiners and other large end-users of petroleum products.

Our marine terminals primarily receive petroleum products by ship and barge, short-haul pipeline connections from neighboring refineries and common carrier pipelines. We distribute petroleum products from our marine terminals by all of those means as well as by truck and rail. Products that we store include refined petroleum products, blendstocks, crude oils, heavy oils and feedstocks. In addition to providing storage and distribution services, our marine terminals provide ancillary services including heating, blending and mixing of stored products and additive injection services.

Our marine terminals generate fees primarily through providing long-term storage services for a variety of customers. Refiners and chemical companies will typically use our marine terminals because their facilities are inadequate, either because of size constraints 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.

Customers and Contracts. We have long-standing relationships with oil refiners, suppliers and traders at our facilities. During 2009, approximately 98% of our marine terminal capacity was utilized. As of December 31, 2009, over 85% of our usable storage capacity was under long-term contracts with remaining terms in excess of one year or that renew on an annual basis. These contracts obligate the customer to pay for terminal capacity reserved even if not used by the customer.

Markets and Competition. We believe that the continued strong demand for our marine terminals results from our cost-effective distribution services and key transportation links, providing a stable base of storage fee revenues. The additional heating and blending services we provide at our marine terminals attract additional demand for our storage services and result in increased revenue opportunities. Demand can also 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 refined petroleum products through their proprietary terminals, we could experience increased competition for the services we provide. In addition, other companies have facilities that offer competing storage and distribution services.

Inland Terminals

We own and operate a network of 27 refined petroleum products terminals located primarily in the southeastern United States. We wholly own 25 of the 27 terminals in our portfolio. Our terminals have a combined capacity of more than 5 million barrels. Our customers utilize these facilities to take delivery of refined petroleum products transported on major common carrier interstate pipelines. The majority of our inland terminals connect to the Colonial, Explorer, Plantation or TEPPCO pipelines, and some facilities have multiple pipeline connections. Our inland terminals typically consist of multiple storage tanks that are connected to these third-party pipeline systems. We load and unload products through an automated system that allows products to move directly from the common carrier pipeline to our storage tanks and directly from our storage tanks to a truck or railcar loading rack. During 2009, gasoline represented approximately 66% of the product volume distributed through our inland terminals, with the remaining 34% consisting of distillates.

We are an independent provider of storage and distribution services. We operate our inland terminals as distribution terminals, primarily serving the retail, industrial and commercial sales markets. We provide inventory and supply management, distribution and other services such as injection of gasoline additives at our inland terminals. Due to the increasing use of renewable fuels in the Southeast, we have added ethanol blending capabilities at most of our inland terminals.

We generate revenues by charging our customers a fee based on the amount of product we deliver through our inland terminals. We charge these fees when we deliver the product to our customers and load it into a truck or railcar. In addition to throughput fees, we generate revenues by charging our customers a fee for injecting additives into their petroleum products. In addition, we generate product margins from the sale of terminal product gains.

Customers and Contracts. We enter into contracts with customers that typically last for one year with a provision that, at the end of each contract's term, automatically renews the contract for another one-year period. A number of these contracts contain a minimum throughput provision that obligates the customer to move a minimum amount of product through our terminals or pay for terminal capacity reserved but not used. Our customers include retailers, wholesalers, exchange transaction customers and traders.

Markets and Competition. We 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 competition primarily comes from distribution companies with marketing and trading arms, independent terminal operators and refining and marketing companies.

AMMONIA PIPELINE SYSTEM

We own an 1,100-mile common carrier ammonia pipeline system. Our pipeline system transports ammonia from production facilities in Texas and Oklahoma to terminals in the Midwest. The ammonia we transport is primarily used as a nitrogen fertilizer. The ammonia pipeline system segment accounted for 1%, 2% and 2% of our consolidated total revenues for the years ended December 31, 2007, 2008 and 2009. See Note 18—Segment Disclosures in the accompanying consolidated financial statements for financial information about the ammonia pipeline system segment.

Operations. We generate more than 90% of our ammonia pipeline system revenues through transportation tariffs and by charging our customers for services at the six terminals we own. We do not produce or trade ammonia, and we do not take title to the ammonia we transport. We own 28 thousand tons of anhydrous ammonia, which is approximately 80% of the linefill.

Facilities. Our ammonia pipeline system originates at production facilities in Borger, Texas and Enid and Verdigris, Oklahoma and terminates in Mankato, Minnesota. We transport ammonia to 13 delivery points along our ammonia pipeline system, including to six terminals that we own. The facilities at these points provide our customers with the ability to deliver ammonia to distributors who sell the ammonia to farmers, to store ammonia for future use and to remove ammonia from our pipeline for distribution to upgrade facilities that produce complex nitrogen compounds.

Customers and Contracts. We ship ammonia for three customers. Each of these customers has an ammonia production facility as well as related storage and distribution facilities connected to our ammonia pipeline. In 2008, we negotiated new five-year transportation agreements with our three customers which extend through June 30, 2013. Each transportation agreement contains a ship-or-pay provision whereby each customer committed a tonnage that it expects to ship. If a customer fails to ship its annual commitment, that customer must pay for the unused pipeline capacity. Aggregate annual commitments from our customers for the period July 1, 2009 through June 30, 2010 are 550,000 tons.

Markets and Competition. Demand for nitrogen fertilizer has typically followed a combination of weather patterns and growth in population, acres planted and fertilizer application rates. Because natural gas is the primary feedstock for the production of ammonia, the profitability of our customers is impacted by natural gas prices. To the extent our customers are unable to pass on higher costs to their customers, they may reduce shipments through our ammonia pipeline system.

We compete primarily with ammonia shipped by rail carriers. Because the transportation and storage of ammonia requires specialized handling, we believe that pipeline transportation is the safest and most cost-effective method for transporting bulk quantities of ammonia. We also compete to a limited extent in the areas served by the far northern segment of our ammonia pipeline system with an ammonia pipeline owned by NuStar Energy, which originates on the Gulf Coast and transports domestically produced and imported ammonia.

GENERAL BUSINESS INFORMATION

Major Customers

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 revenue for 2007, 2008 or 2009. The majority of the revenues from Customers A, B and C resulted from sales to those customers of refined petroleum products that were generated in connection with our petroleum products blending and fractionation activities. Customer D purchased petroleum products from us pursuant to a third-party supply agreement that we assigned in March 2008. In general, accounts receivable from these customers are due within 3 days of sale.

	Year Ended December 31,		
	2007	2008	2009
Customer A	1%	12%	11%
Customer B	2%	12%	5%
Customer C	13%	8%	0%
Customer D	33%	2%	0%
Total	49%	34%	16%

Tariff Regulation

Interstate Regulation. Our petroleum 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 oil pipeline rates be filed with the FERC and posted publicly and that these rates be "just and reasonable" and nondiscriminatory. Rates of interstate oil pipeline companies, like some of those charged for our petroleum products pipeline system, are currently regulated by FERC primarily through an index methodology, which for the current five-year period, ending with our rate change to our tariffs in July 2010, is set at the producer price index for finished goods ("PPI-FG") plus 1.3%.

Under the indexing regulations, a pipeline can request a rate increase that exceeds index levels for indexed rates using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rate resulting from application of the FERC index. Approximately 40% of our petroleum products pipeline system is subject to this indexing methodology. In addition to rate indexing and cost-of-service filings, interstate oil 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 service in question. Approximately 60% of our petroleum products pipeline system's markets are deemed competitive by the FERC, and we are allowed to charge market-based rates in these markets.

In May 2005, the FERC adopted a policy statement stating that it would permit entities owning public utility assets, including oil pipelines, to include an income tax allowance in such utilities' cost-of-service rates to reflect actual or potential tax liability attributable to their public utility income, regardless of the form of ownership. Pursuant to this policy statement, a tax pass-through entity seeking such an income tax allowance would have to establish that its partners or members have an actual or potential income tax obligation on the entity's public utility income. This tax allowance policy was upheld by the D.C. Circuit in May 2007. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although this policy is generally favorable for pipelines that are organized as pass-through entities, it still entails rate risk due to the case-by-case review requirement. We do not currently use cost-of-service as a basis for establishing our rates.

The Surface Transportation Board ("STB"), a part of the United States 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. If the STB finds that a carrier's rates violate these statutory commands, it may prescribe a reasonable rate. In determining a reasonable rate, the STB will consider, among other factors, the effect of the rate on the volumes transported by that carrier, the carrier's revenue needs and the availability of other economic transportation alternatives. The STB does not need to provide rate relief unless shippers lack effective competitive alternatives. If the STB determines that effective competitive alternatives are not available and a pipeline entity holds market power, then the pipeline entity may be required to show that its rates are reasonable.

Intrastate Regulation. Some shipments on our petroleum products pipeline system move within a single state and thus are considered to be intrastate commerce. Our petroleum products pipeline system is subject to certain regulation with respect to such intrastate transportation by state regulatory authorities in the states of Colorado, Illinois, Kansas, Minnesota, Oklahoma and Texas. However, in most instances, the state commissions have not initiated investigations of the rates or practices of petroleum products pipelines.

Because in some instances we transport ammonia between two terminals in the same state, our ammonia pipeline operations are subject to regulation by the state regulatory authorities in Iowa, Nebraska, Oklahoma and Texas. Although the Oklahoma Corporation Commission and the Texas Railroad Commission have the authority to regulate our rates, the state commissions have generally not investigated the rates or practices of ammonia pipelines in the absence of shipper complaints.

Market Manipulation Regulations

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 its Petroleum Market Manipulation Rule, which became effective November 4, 2009, and 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 petroleum products. The 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.

Additional proposals and proceedings that might affect the petroleum industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our petroleum products operations. We do not believe that we would be affected by any such FERC action materially differently than similarly situated companies.

Environmental, Maintenance & Safety

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 providing an employment workplace that is free from recognized hazards. 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 as well as 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 only, and the 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 have the potential to have a material adverse effect on our results of operations, financial position and cash flow.

Environmental Liabilities. Liabilities recognized for estimated environmental costs were $41.8 million and $34.4 million at December 31, 2008 and December 31, 2009, 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 paid over the next ten years.

In February 2007, we received notice from the Department of Justice ("DOJ") that the Environmental Protection Agency ("EPA") had requested the DOJ to initiate a lawsuit alleging violations of Sections 301 and 311 of the Clean Water Act with respect to two releases of anhydrous ammonia from our ammonia pipeline system which was operated by a third party at the time of the releases. In March 2007, we also received a demand from the third-party operator for defense and indemnification. In October 2009, we paid a penalty of $3.7 million to the EPA and agreed to perform certain operational enhancements. Further, we settled the third-party operator defense and indemnification for $0.8 million in December 2009.

Environmental Receivables. Receivables from insurance carriers related to environmental matters were $4.5 million and $3.9 million at December 31, 2008 and December 31, 2009, respectively.

Environmental Insurance Policies. We have insurance policies which 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 on the majority of our petroleum products pipeline system that have various terms, with most expiring between 2014 and 2017. In conjunction with acquisitions, we generally purchase pollution legal liability insurance to cover pre-existing unknown conditions for the acquired assets for a period of time.

Clean Air Act. Our operations are subject to the federal Clean Air Act ("CAA"), as amended 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 CAA requires each state to assess fees against major stationary emission sources in "severe" or "extreme" non-attainment areas. During 2009, the Texas Commission on Environmental Quality ("TCEQ"), in response to an EPA request, issued proposed rules which, if adopted as proposed, may result in fees assessed against our Galena Park, Texas terminal for the 2008 and 2009 calendar years of up to $8.1 million and $4.8 million, respectively.

In recent guidance, the EPA has indicated that a Section 185 fee program is not necessary for areas that have obtained the ozone standard as demonstrated through three consecutive years of monitoring data. Based on the monitoring data for the Houston/Galveston/Brazoria, Texas area prepared by the TCEQ, which indicates that the area obtained the ozone standard for the past three consecutive years, management believes the mostly likely outcome will be that the EPA will recognize that the area has attained the ozone standard and that no fees will be assessed. However, management believes it is reasonably possible that the TCEQ could adopt its rules as proposed. Management believes that should the TCEQ adopt its proposed rules, because of special circumstances unique to our permits, the fees that would ultimately be assessed against our facility could be substantially reduced from the amounts described above. At December 31, 2009, we had no amounts accrued for this matter.

Petroleum Products Blending Review. As a result of an ongoing internal operational review of our petroleum products blending activity, we have disclosed instances of regulatory non-compliance to the EPA. We have not met with the EPA on this matter, however, management believes that this situation will not result in the imposition of any material fines or penalties on us by the EPA.

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 will 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 will be 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, recordkeeping and protection of chemical-terrorism vulnerability information. We have received a preliminary risk ranking of our facilities from the DHS, and we are in the process of determining how these risk rankings will impact each of our facilities.

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, 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 also 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, including many oil and gas exploration and production wastes, from being subject to hazardous waste requirements, the EPA can 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 the Superfund law, 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 significant.

Water Discharges. Our operations can result in the discharge of pollutants, including oil. The Oil Pollution Act was enacted in 1990 and amends provisions of the Federal Water Pollution Control Act of 1972 ("Water Pollution Control Act") and other statutes as they pertain to prevention and response to 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 shorelines or in the exclusive economic zone of the United States. 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 the costs of non-compliance and damages. 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 will have a material adverse effect on our results of operations, financial position or cash flows.

Maintenance. Our pipeline systems are subject to regulation by the United States Department of Transportation under the Hazardous Liquid Pipeline Safety Act ("HLPSA") of 1979, as amended, and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. HLPSA covers petroleum, petroleum products and anhydrous ammonia and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to 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 are subject to United States 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. The OSHA hazard communication standard and comparable state statutes 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.

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 are revocable at the election of the grantor. 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. The previous owners of the applicable pipelines may not have commenced or concluded eminent domain proceedings for some rights-of-way.

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 a failure to obtain all consents, permits or authorizations will not have a material adverse effect on the operation of our business.

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 that arise before February 2016 and title defects related to the portion of our petroleum products pipeline system acquired in April 2002 that arise before April 2012. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with 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, 2009, we had 1,217 employees. At December 31, 2009, the labor force of 608 employees assigned to our petroleum products pipeline system was concentrated in the central United States. Approximately 36% of these employees were represented by the United Steel Workers Union ("USW"). Our collective bargaining agreement with the USW expires January 31, 2012. The labor force of 270 employees assigned to our petroleum products terminals operations at December 31, 2009 was primarily concentrated in the southeastern and Gulf Coast regions of the United States. Approximately 11% of these employees were represented by the International Union of Operating Engineers ("IUOE") and covered by a collective bargaining agreement that expires in October 2010. At December 31, 2009, the labor force of 19 employees assigned to our ammonia pipeline system was concentrated in the central United States and none of these employees were covered by a collective bargaining agreement.

(d) Financial Information About Geographical Areas

We have no revenue or expense attributable to international activities.

(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 Internet 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 Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

ITEM 1A. *Risk Factors*

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

Risks Related to Our Business

We may not be able to generate sufficient cash from operations to allow us to pay quarterly distributions at current levels following establishment of cash reserves and payment of fees and expenses.

The amount of cash we can distribute on our limited partner units principally depends upon the cash we generate from our operations. Because the cash we generate from operations will fluctuate from quarter to quarter, we may not be able to pay quarterly distributions at the current level for each quarter. Our ability to pay quarterly distributions depends primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. As a result, we may pay cash distributions during periods when we record losses and may be unable to pay cash distributions during periods when we record net income.

Our financial results depend on the demand for the petroleum products that we transport, store and distribute, among other factors, and the current economic downturn could result in lower demand for these products for a sustained period of time.

Any sustained decrease in demand for petroleum products in the markets served by our pipeline and terminals could result in a significant reduction in the volume of products that we transport in our pipeline, store at our marine terminals and distribute through our inland terminals, and thereby reduce our cash flow and our ability to pay cash distributions. Economic conditions worldwide have from time to time resulted in reduced demand for the products transported and stored by our pipelines and terminals and the services that we provide. Our financial results may also be affected by uncertain or changing economic conditions within certain regions, including the challenges that are currently affecting economic conditions in the entire United States. If economic and market conditions remain uncertain or adverse conditions persist, spread or deteriorate further, we may experience material impacts on our business, financial condition and results of operations. Other factors that could lead to a decrease in market demand include:

- an increase in the market prices of petroleum products, which may reduce demand for gasoline and other petroleum products. Market prices for petroleum products are subject to wide fluctuations in response to changes in global and regional supply and demand over which we have no control;
- higher fuel taxes or other governmental or regulatory actions that increase the cost of the products we handle;
- an increase in fuel economy, whether as a result of a shift by consumers to more fuel-efficient vehicles, technological advances by manufacturers or federal or state regulations; and
- an increase in the use of alternative fuel sources, such as ethanol, biodiesel, fuel cells and solar, electric and battery-powered engines. Current laws will require a significant increase in the quantity of ethanol and biodiesel used in transportation fuels between now and 2022. Such an increase could have a material impact on the volume of fuels transported on our pipeline or loaded at our terminals.

Our business involves many hazards and operational risks, some of which may not be covered by insurance.

Our operations are subject to many hazards inherent in the transportation and distribution of petroleum products and ammonia, including ruptures, leaks and fires. In addition, our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes. Our storage and pipeline facilities located near the U.S. Gulf Coast, for example, have experienced damage and interruption of business due to hurricanes. These risks could result in substantial losses due to personal injury or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage, and may result in curtailment or suspension of our related operations. We are not fully insured against all risks incident to our business. In addition, as a result of market conditions, premiums for our insurance policies could increase significantly. In some instances, insurance could become unavailable or available only for reduced amounts of coverage. If a significant accident or event occurs that is not fully insured, it could adversely affect our results of operations, financial position or cash flows and our ability to pay cash distributions.

Fluctuations in prices of refined petroleum products and natural gas liquids that we purchase and sell could materially affect our earnings.

We generate product sales revenues from our petroleum products blending and fractionation activities, as well as from the sale of product generated by the operation of our pipeline and terminals. We also maintain product inventory related to these activities. In addition, we own the linefill inventory required for the operation of the pipeline acquired in the Longhorn acquisition in July 2009, and since that acquisition we have purchased and sold refined petroleum products in connection with the operation of those assets. Significant fluctuations in market prices of petroleum products could result in losses or lower profits from these activities, thereby reducing the amount of cash we generate and our ability to pay cash distributions. Additionally, significant fluctuations in market prices of petroleum products would result in significant unrealized gains or losses on our open NYMEX positions. To the extent these NYMEX contracts have not been designated as hedges for accounting purposes, the associated non-cash unrealized gains and losses would directly impact our earnings.

We hedge prices of refined products by utilizing physical purchase and sale agreements, futures contracts traded on the New York Mercantile Exchange ("NYMEX"), options contracts or over-the-counter transactions. These hedging arrangements may not eliminate all price risks, could result in fluctuations in quarterly or annual profits and could result in material cash obligations that could negatively impact our financial position or our ability to pay distributions to our unitholders.

We hedge our exposure to price fluctuations with respect to our refined products purchase and sale activities by utilizing physical purchase and sale agreements, futures contracts traded on the NYMEX, options contracts or over-the-counter transactions. To the extent these hedges do not qualify for hedge accounting treatment under Accounting Standards Codification 815-30, *Derivatives and Hedging*, or they result in material amounts of ineffectiveness, we could experience material fluctuations in our quarterly or annual results of operations. In addition, to the extent these hedges are entered into on a public exchange, we may be required to post margin which could result in material cash obligations. Finally, these contracts may be for the purchase or sale of product in markets different from those in which we are attempting to hedge our exposure, resulting in hedges that do not eliminate all price risks.

We are exposed to counterparty credit risk. Nonpayment and nonperformance by our customers, vendors or derivative counterparties could reduce our revenues, increase our expenses or otherwise negatively impact our operating results, cash flows and ability to pay cash distributions.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers to whom we extend credit. In addition, nonperformance by vendors who have committed to provide products or services to us could result in higher costs or interfere with the conduct of our business. Furthermore, nonpayment by the counterparties to our interest rate and commodity derivatives could expose us to additional interest rate or commodity price risk. Any substantial increase in the nonpayment or nonperformance by our customers, vendors or counterparties could have a material adverse effect on our results of operations and cash flows.

We rely on access to capital to fund acquisitions and growth projects and to refinance existing debt obligations. Unfavorable developments in capital markets could limit our ability to obtain funding or require us to secure funding on terms that will limit our financial flexibility, reduce our liquidity, dilute the interests of our existing unitholders and/or reduce our cash flows and ability to pay distributions.

We regularly consider and pursue growth projects and acquisitions as part of our efforts to increase cash available for distribution to our unitholders. These transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets and operations. We do not retain sufficient cash flow to finance these projects and acquisitions internally, and consequently the execution of our growth strategy requires regular access to outside sources of capital. Any limitations on our access to capital on satisfactory terms will impair our ability to execute this strategy. Similarly, we generally do not retain sufficient cash flow to repay our indebtedness when it matures and will rely on new capital to refinance these obligations. Limitations on our access to capital, including on our ability to issue additional debt and equity, could result from events or causes beyond our control, and could include, among other factors, significant increases in interest rates, increases in the risk premium required by investors, generally, or for investments in energy-related companies or master limited partnerships, decreases in the availability of credit or the tightening of terms required by lenders. Any limitations on our ability to refinance these obligations by securing new capital on satisfactory terms could severely limit our liquidity, our financial flexibility and/or our cash flows, and could result in the dilution of the interests of our existing unitholders.

The current economic environment amplifies certain risks inherent in our business.

During 2007, the U.S. and many other countries began to exhibit signs of economic weakness, which continued throughout 2008 and 2009, and into 2010. This weakness had a significant adverse impact on the capital markets and financial system in the United States and the global financial system in general, resulting in a significant reduction in available capital. Capital constraints coupled with significant energy price volatility have resulted in pervasive financial and liquidity issues for many companies, including some of our customers. Such events have created uncertainty in the economic outlook and have amplified the potential impact and likelihood of the occurrence of certain risks inherent in our business. Such risks include:

- increased cost of capital and increased difficulties accessing capital to fund expansion and acquisition activities;
- the inability or unwillingness of lenders to honor their contractual commitments;
- the failure of customers to timely or fully pay amounts due to us;
- the failure of suppliers to pay third parties under obligations for which we have potential contingent liabilities;
- the failure of counterparties to fulfill their delivery or purchase obligations; and
- the potential for adverse actions by rating agencies.

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

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

Rate regulation or a successful challenge to the rates we charge on our petroleum products pipeline system may reduce the amount of cash we generate.

The FERC regulates the tariff rates for interstate movements on our petroleum products pipeline system. Shippers may protest our pipeline tariff filings, and the FERC may investigate new or changed tariff rates. Further, other than for rates set under market-based rate authority, the FERC may order refunds of amounts collected under newly filed rates that are determined by the FERC to be in excess of a just and reasonable level when taking into consideration our pipeline system's cost-of-service. In addition, shippers may challenge by complaint the lawfulness of tariff rates that have become final and effective. The FERC may also investigate tariff rates absent shipper complaint. If existing rates challenged by complaint are determined by the FERC to be in excess of a just and reasonable level when taking into consideration our pipeline system's cost-of-service, the FERC could require the payment of reparations to complaining shippers for up to two years prior to the complaint.

The FERC's ratemaking methodologies may limit our ability to set rates based on our true costs or may delay the use of rates that reflect increased costs. The FERC's primary ratemaking methodology is price indexing. We use this methodology to establish our rates in approximately 40% of our markets. The current indexing method allows a pipeline to change its rates each year to the new ceiling level, which is calculated as the previous year's ceiling level multiplied by a percentage equal to the change in the PPI-FG plus 1.3%. If the PPI-FG falls and our rates are at the ceiling level, we would be required to reduce our rates that are based on the FERC's price indexing methodology. The FERC's indexing methodology is subject to review every five years; the current methodology will remain in place through our tariff rate change in July 2010. For instance, the change in the PPI-FG is estimated to be approximately negative 2.5% for 2009. As a result, we expect to lower our tariffs by approximately 1.2% in July 2010 in these indexation markets.

We establish rates in approximately 60% of our markets using the FERC's market-based ratemaking regulations. These regulations allow us to establish rates based on conditions in individual markets without regard to the index or our cost-of-service. If we were to lose our market-based rate authority, we would then be required to establish rates on some other basis, such as our cost-of-service. Any reduction in the indexed rates, removal of our ability to establish market-based rates or payment of reparations could have a material adverse effect on our results of operations and reduce the amount of cash we generate.

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

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

We use the FERC's PPI-based price indexing methodology to establish tariff rates in approximately 40% of the markets served by our petroleum products pipeline system. The indexing method requires a pipeline to change its rates by a percentage equal to the change in the PPI-FG plus 1.3%. This methodology could result in changes in our revenues that do not fully reflect changes in the costs we incur to operate and maintain our petroleum products pipeline system. For example, our costs could increase more quickly or by a greater amount than the PPI-FG index plus 1.3% currently used by the FERC methodology. Further, in periods of general price deflation, the PPI-FG index could fall, in which case we could be required to reduce our index-based rates, even if the actual costs we incur to operate our assets increase. Changes in price levels that lead to decreases in our revenues or increases in the prices we pay to operate and maintain our assets could adversely affect our results of operations, liquidity and ability to pay distributions.

Our business is subject to federal, state and local laws and regulations that govern the environmental and operational safety aspects of our operations and that could increase our costs and liabilities.

Each of our operating segments is subject to the risk of incurring substantial costs and liabilities under environmental and safety laws and regulations. These costs and liabilities arise under increasingly stringent environmental and safety laws, including regulations and governmental enforcement policies, and as a result of claims for damages to property or persons arising from our operations. Failure to comply with these laws and regulations may result in assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens and, to a lesser extent, issuance of injunctions to limit or cease operations. If we were unable to recover these costs through increased revenues, our ability to meet our financial obligations and pay cash distributions could be adversely affected.

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

Further, the transportation of hazardous materials in our pipelines may result in environmental damage, including accidental releases that may cause death or injuries to humans, third-party damage, natural resource damages, and/or result in federal and/or state civil and/or criminal penalties that could be material to our results of operations and cash flows.

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

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

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

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the federal CAA. Accordingly, the EPA had proposed two sets of CAA regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, in October 2009, the EPA issued a final CAA rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including sources that emit more than 25,000 tons of greenhouse gases on an annual basis, beginning in 2011 for emissions occurring in 2010. The adoption and implementation of any CAA regulations limiting emissions of greenhouse gases from our equipment and operations or those of customers for whom we transport, store or deliver product, could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for our services.

In addition, in June 2009, the U.S. House of Representatives passed the "American Clean Energy and Security Act of 2009" ("ACESA"), which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases. ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. These allowances would be expected to escalate significantly in cost over time. The net effect of ACESA would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products and natural gas. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions and the Obama Administration has indicated its support of legislation to reduce greenhouse gas emissions through an emission allowance system. 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. It is not possible at this time to predict when the Senate may act on climate change legislation, how any bill passed by the Senate would be reconciled with ACESA or how state and federal legal and regulatory initiatives will interact.

The effect on our operations of CAA regulations, legislative efforts or related implementation regulations that regulate or restrict emissions of greenhouse gases in areas that we conduct business could adversely affect the demand for the products that we transport, store and distribute and, depending on the particular program adopted, could increase our costs to operate and maintain our facilities, measure and report our emissions, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. We may be unable to include some or all of such increased costs in the rates charged by our pipelines or other facilities, and any such recovery may depend on events beyond our control, including the outcome of future rate proceedings before the FERC or state regulatory agencies and the provisions of any final legislation or implementing regulations.

In addition, some scientists have concluded that increasing concentrations of greenhouse gases in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climate events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

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

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

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

We depend on connections with refineries and petroleum products pipelines owned and operated by third parties as a significant source of supply for our facilities. Outages at these refineries or reduced or interrupted throughput on these pipelines because of weather-related or other natural causes, testing, line repair, damage, reduced operating pressures or other causes could result in our being unable to deliver products to our customers from our terminals or receive products for storage or reduce shipments on our pipelines and could adversely affect our cash flows and ability to pay cash distributions.

The closure of refineries that supply our petroleum products pipeline system could result in disruptions or reductions in the volumes we transport and store and in the amount of cash we generate.

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

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

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

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

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

Potential future acquisitions and expansions, if any, may affect our business by substantially increasing the level of our indebtedness and liabilities and increasing our risk of being unable to effectively integrate these new operations.

From time to time, we evaluate and acquire assets and businesses that we believe complement our existing assets and businesses. Acquisitions may require substantial capital or the incurrence of substantial indebtedness. If we consummate any future acquisitions, our capitalization and results of operations may change significantly.

Acquisitions and business expansions involve numerous risks, including difficulties in the assimilation of the assets and operations of the acquired businesses, inefficiencies and difficulties that arise because of unfamiliarity with new assets and the businesses associated with them and new geographic areas and the diversion of management's attention from other business concerns. Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. Following an acquisition, we may discover previously unknown liabilities associated with the acquired business for which we have no recourse under applicable indemnification provisions.

We completed the Longhorn acquisition in July 2009. The purchase price was $252.3 million plus $86.1 million for related linefill inventory. We financed the acquisition with debt, which substantially increased our indebtedness. Subsequently, we purchased additional inventory to facilitate product shipments on the pipeline. Because the assets included in the Longhorn acquisition had minimal commercial activity following the former owner's 2008 bankruptcy filing, we anticipate a ramp-up of operations through 2012 as a customer base is built for this pipeline system. During that period, the operating cash flow derived from the assets may be significantly less than we ultimately anticipate once the customer base has been developed. As a result, our cash from operations and our credit metrics could be adversely affected during that ramp-up period. In addition, during that period, we will likely continue to own a significant portion of the related linefill inventory, and we could be exposed to price fluctuations in the value of that inventory, or to margin deposits or similar arrangements required by any transactions we enter to hedge the value of that inventory. We cannot assure that the ramp-up period will be limited to one or two years or that we will ever build a substantial customer base for this pipeline system. In addition, we could experience other unanticipated delays in realizing the benefits of the acquisition, or we could discover previously unknown liabilities associated with the acquired assets.

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

We have begun or anticipate beginning numerous expansion projects which will require us to make significant capital investments. We will incur financing costs during the planning and construction phases of these projects; however, the operating cash flows we expect these projects to generate will not materialize, if at all, until some time after the projects are completed. The amount of time and investment necessary to complete these projects could exceed the estimates we used when determining whether to undertake them. For example, we must compete with other companies for the materials and construction services required to complete these projects, and competition for these materials or services could result in significant delays and/or cost overruns. Any such cost overruns or unanticipated delays in the completion or commercial development of these projects could reduce our liquidity and our ability to pay cash distributions.

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

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

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

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

Since the September 11, 2001 terrorist attacks, the U.S. government has issued warnings that energy assets in general, and the nation’s pipeline and terminal infrastructure in particular, may be future targets of terrorist organizations. The threat of terrorist attacks has subjected our operations to increased risks. Any future terrorist attack on our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business. Similarly, any future terrorist attacks that severely disrupt the markets we serve could adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

High natural gas prices can increase ammonia production costs and reduce the amount of ammonia transported through our ammonia pipeline system.

The profitability of our ammonia customers partially depends on the price of natural gas, which is the principal raw material used in the production of ammonia. An extended period of high natural gas prices may cause our customers to produce and ship lower volumes of ammonia, which could adversely affect our cash flows.

Increases in interest rates could increase our financing costs and reduce the amount of cash we generate.

As of December 31, 2009, we had $1,651.6 million of debt outstanding (excluding net premiums on debt issuances and fair value adjustments). Of this amount, approximately $351.6 million, or 21% was subject to variable interest rates, including $101.6 million of floating rate borrowings outstanding on our revolving credit facility and $250.0 million of fixed-rate debt converted to floating rates using interest rate swap agreements. We also expect to make additional floating-rate borrowings under our revolving credit facility to partially finance future expansion capital spending. As a result, we have exposure to changes in short-term interest rates. In addition, the execution of our growth strategy and the refinancing of our existing debt could require that we issue additional fixed-rate debt, and consequently we also have potential exposure to changes in long-term interest rates. Rising interest rates could reduce the amount of cash we generate and adversely affect our liquidity and our ability to pay cash distributions.

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

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

Risks Related to Our Partnership Structure

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

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

Our unit purchase rights plan may make it more difficult for others to obtain control of us.

We currently have a unit purchase rights plan, commonly referred to as a "poison pill." This poison pill will cause substantial dilution to the ownership of a person or group that attempts to acquire us on terms not approved by our general partner's board of directors and may have the effect of deterring future takeover attempts. The practical effect of a poison pill is to require a party seeking control of us to negotiate with our general partner's board of directors, which could delay or prevent a change in control of us and the replacement or removal of management. This poison pill, coupled with other antitakeover provisions in our partnership agreement and under Delaware law, could discourage a future takeover attempt which individual unitholders might deem to be in their best interests or in which unitholders would receive a premium for their limited partner units over current prices.

Tax Risks to Limited Partner Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service ("IRS") were to treat us as a corporation for federal income tax purposes or if we become subject to a material amount of entity-level taxation for state tax purposes, it would reduce the amount of cash available for distribution to our unitholders.

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

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

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

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

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. For example, at the federal level, legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact a unitholder's investment in our limited partner units. At the state level, because of widespread state budget deficits and for other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, partnerships operating in Texas are required to pay franchise tax at a maximum effective rate of 0.7% of gross income apportioned to Texas in the prior year. If any other state were to impose a tax on us, our cash flows could be materially reduced.

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

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

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

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

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

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

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

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

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

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

We prorate our items of income, gain, loss and deduction between transferors and transferees of our limited partner units each month based upon the ownership of our limited partner units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our limited partner units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. Recently, however, the Department of the Treasury and the IRS issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Although existing publicly traded partnerships are entitled to rely on these proposed Treasury Regulations, they are not binding on the IRS and are subject to change until final Treasury Regulations are issued.

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

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

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between our partners. The IRS may challenge this treatment, which could adversely affect the value of our limited partner units.

When we issue additional limited partner units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our partners. The IRS may challenge our valuation methods, or our allocation of the Internal Revenue Code Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our partners. A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of our limited partner units and could have a negative impact on the value of our limited partner units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

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

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same unit are counted only once. We believe and will take the position that the distribution of our limited partner units in connection with the simplification of our capital structure in September 2009 resulted in our termination and immediate reconstitution as a new partnership for federal income tax purposes, which further resulted in the closing of our taxable year for all unitholders of record in September 2009. Accordingly, we will file two tax returns (and our limited partners could receive two Schedule K-1s) for one fiscal year and we are required to make new tax elections. Our termination for tax purposes results in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year results in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination does not affect our classification as a partnership for federal income tax purposes. The IRS has recently announced a publicly traded partnership technical termination relief program whereby, if the taxpayer requests relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

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

In addition to federal income taxes, our unitholders may be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own assets and conduct business in 22 states, most of which impose a personal income tax. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is our unitholders' responsibility to file all U.S. federal, state and local tax returns.

ITEM 1B. *Unresolved Staff Comments*

None.

ITEM 2. *Properties*

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

ITEM 3. *Legal Proceedings*

Ammonia EPA issue. In February 2007, we received notice from the Department of Justice ("DOJ") that the Environmental Protection Agency ("EPA") had requested the DOJ to initiate a lawsuit alleging violations of Sections 301 and 311 of the Clean Water Act with respect to two releases of anhydrous ammonia from our ammonia pipeline system which was operated by a third party at the time of the releases. In March 2007, we also received a demand from the third-party operator for defense and indemnification. In October 2009, we paid a penalty of $3.7 million to the EPA and agreed to perform certain operational enhancements. Further, we settled the third-party operator defense and indemnification for $0.8 million in December 2009.

In June 2008, we received a Notice of Probable Violation ("NOPV") from the Department of Transportation, Pipeline and Hazardous Materials Safety Administration ("DOT PHMSA") for alleged violations associated with a May 2005 pipeline release that occurred in Kansas. We settled this matter in October 2009 and paid a penalty of $0.6 million.

In June 2009, we received notice from the DOJ that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Sections 301 and 311 of the Clean Water Act with respect to a release of petroleum product that occurred in Oklahoma in January 2008. The DOJ stated that the maximum statutory penalty for alleged violations of the Act for the release was approximately $1.2 million. As a result of subsequent negotiations, we and the EPA have agreed on a settlement in the amount of $0.4 million. The settlement does not require that we perform any operational enhancements. We anticipate that the settlement will be finalized during the first quarter of 2010.

We are a party to various other claims, legal actions and complaints arising in the ordinary course of business. In the opinion of management, the ultimate resolution of these claims, legal actions and complaints after consideration of amounts accrued, insurance coverage or other indemnification arrangements will not have a material adverse effect on our future financial position, results of operations or cash flows.

ITEM 4. *Submission of Matters to a Vote of Security Holders*

None.

PART II

ITEM 5. *Market for Registrant's Limited Partner Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Our limited partner units trade on the NYSE under the ticker symbol "MMP".

At the close of business on February 1, 2010, we had 300 registered holders and approximately 90,500 beneficial holders of record of our limited partner units. The year-end closing sales price of our limited partner units was $30.21 on December 31, 2008 and $43.33 on December 31, 2009. The high and low trading price ranges for and distributions paid on our limited partner units by quarter for 2008 and 2009 were as follows:

	2008			2009		
Quarter	High	Low	Distribution*	High	Low	Distribution*
1st	$45.00	$38.34	$0.67250	$36.00	$25.36	$0.71000
2nd	$43.61	$35.47	$0.68750	$36.75	$28.93	$0.71000
3rd	$38.06	$29.51	$0.70250	$39.92	$33.75	$0.71000
4th	$37.32	$18.85	$0.71000	$43.70	$36.55	$0.71000

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

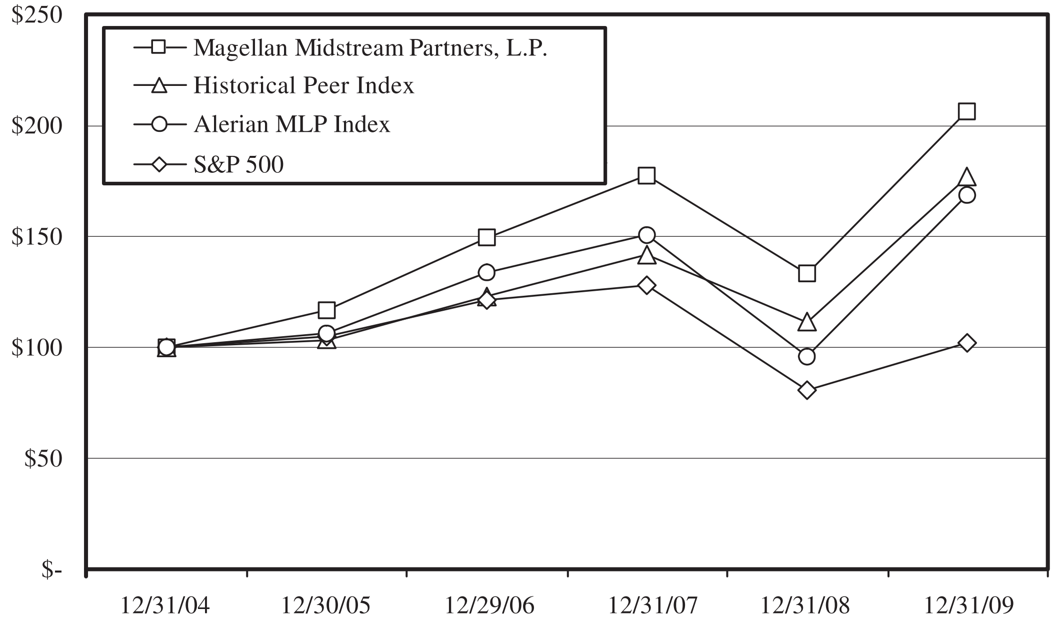
We must distribute all of our available cash, as defined in our partnership agreement, at the end of each quarter, less reserves established by our general partner. We currently pay quarterly cash distributions of $0.71 per limited partner unit. In general, we intend to increase our cash distribution. However, we cannot guarantee that future distributions will increase or continue at current levels.

Unitholder Return Performance Presentation

The following graph compares the total unitholder return performance of our limited partner units with the performance of (i) the Standard & Poor's 500 Stock Index ("S&P 500"), (ii) a historical peer index we created and (iii) the Alerian MLP index. The graph assumes that $100 was invested in our limited partner units and each comparison index beginning on December 31, 2004 and that all distributions or dividends were reinvested on a quarterly basis.

We used the historical peer index when there was no published index with which to compare our performance. The peer index includes the following master limited partnerships, which represented the largest, growth-oriented publicly traded partnerships at the time we created it: Enterprise Products Partners L.P. (NYSE: EPD), Kinder Morgan Energy Partners, L.P. (NYSE: KMP), NuStar Energy L.P. (NYSE: NS) and TEPPCO Partners, L.P. (NYSE: TPP). Effective October 2009, TPP merged into EPD.

The Alerian MLP index represents a composite index of the 50 most prominent energy master limited partnerships. We believe the Alerian MLP index provides a more meaningful comparison because it more accurately reflects the increased number of master limited partnerships that have emerged over the past few years as public investment options. We intend to utilize the Alerian MLP index as our peer index for future unitholder return comparisons.



	12/31/04	12/30/05	12/29/06	12/31/07	12/31/08	12/31/09
Magellan Midstream Partners, L.P.	100.0	116.7	149.4	177.6	133.2	206.5
Historical Peer Index	100.0	103.3	123.0	141.9	111.4	176.7
Alerian MLP Index	100.0	106.4	133.8	150.7	95.9	168.7
S&P 500	100.0	104.9	121.4	128.1	80.8	102.1

The information provided in this section is being furnished to, and not filed with, the SEC. As such, this information is neither subject to Regulation 14A or 14C or to the liabilities of Section 18 of the Exchange Act.

ITEM 6. *Selected Financial Data*

The summary selected historical financial data was derived from current and historical audited consolidated financial statements and related notes. The financial information for the periods prior to the effective date of the simplification of our capital structure (the "simplification") (see Note 2—Simplification under Item 8 *Financial Statements and Supplementary Data* of this report) was originally that of Magellan Midstream Holdings, L.P. ("MGG"). Although Magellan Midstream Partners, L.P. was the surviving entity for legal purposes, MGG was the surviving entity for accounting purposes; therefore, all of the historical data included in this Item 6 prior to the simplification is MGG's. Because MGG controlled us prior to the simplification, our financial statements were consolidated with those of MGG. For accounting purposes, the simplification resulted in a reverse unit split, and the historical per-unit amounts presented in this Item 6 have been retrospectively restated accordingly. 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*.

The operating results presented herein incorporate a number of significant estimates and uncertainties. Such matters could cause the data included herein not to be indicative of future financial conditions or results of operations. A discussion of critical accounting estimates and how these estimates could impact future financial conditions 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 which could affect our business and future financial condition and results of operations is included under Item 1A *Risk Factors* of this report. Additionally, Note 4—*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 the accompanying consolidated financial statements.

We define Adjusted EBITDA, which is not a generally accepted accounting principles ("GAAP") measure, in the following schedules as net income plus provision for income taxes, debt prepayment premium, write-off of unamortized debt placement fees, debt placement fee amortization, interest expense (net of interest income and interest capitalized) and depreciation and amortization. Adjusted EBITDA should not be considered an alternative to net income, operating profit, cash flow from operations or any other measure of financial performance presented in accordance with GAAP. Because Adjusted EBITDA excludes some items that affect net income and these items may vary among other companies, the Adjusted EBITDA data presented may not be comparable to similarly titled measures of other companies. Our management uses Adjusted EBITDA as a performance measure to assess the viability of projects and to determine overall rates of return on alternative investment opportunities. A reconciliation of Adjusted EBITDA to net income, the nearest comparable GAAP measure, is included in the following schedules.

In addition to adjusted EBITDA, the non-GAAP measure of operating margin (in the aggregate and by segment) is presented in the following tables. The components of operating margin have been computed using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the following table. See Note 18—Segment Disclosures in the accompanying consolidated financial statements for a reconciliation of segment operating margin to segment operating profit. Management believes that investors benefit from having access to the same financial measures they use. Operating margin is an important measure of the economic performance of our core operations. Operating profit, alternatively, includes expense items such as depreciation and amortization expense and general and administrative ("G&A") expense, that management does not consider when evaluating the core profitability of an operation.

	Year Ended December 31,				
	2005	2006	2007	2008	2009
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenues	$ 501,324	$ 559,321	$ 608,781	$ 638,810	$ 678,945
Product sales revenues	636,209	664,569	709,564	574,095	334,465
Affiliate management fee revenues	667	690	712	733	761
Total revenues	1,138,200	1,224,580	1,319,057	1,213,638	1,014,171
Operating expenses	229,720	243,860	250,935	264,871	257,635
Product purchases	582,631	605,341	633,909	436,567	280,291
Gain on assignment of supply agreement	—	—	—	(26,492)	—
Equity earnings	(3,104)	(3,324)	(4,027)	(4,067)	(3,431)
Operating margin	328,953	378,703	438,240	542,759	479,676
Depreciation and amortization expense	71,655	76,200	79,140	86,501	97,216
G&A expense	61,506	69,503	74,859	73,302	84,049
Operating profit	195,792	233,000	284,241	382,956	298,411
Interest expense, net	52,273	47,624	47,653	50,479	69,187
Debt prepayment premium	—	—	1,984	—	—
Write-off of unamortized debt placement fees	6,413	—	—	—	—
Debt placement fee amortization	2,247	1,925	1,554	767	1,112
Other (income) expense, net	(1,312)	653	728	(380)	(24)
Income before provision for income taxes	136,171	182,798	232,322	332,090	228,136
Provision for income taxes[(a)]	—	—	1,568	1,987	1,661
Net income	$ 136,171	$ 182,798	$ 230,754	$ 330,103	$ 226,475
Net income allocation:[(b)]					
Portion applicable to ownership interests before completion of initial public offering	$ 11,548	$ 5,886	$ —	$ —	$ —
Non-controlling owners' interest	124,623	148,292	175,356	244,430	99,729
Limited partner interests	—	33,069	61,580	87,733	126,476
General partner interest	—	(4,449)	(6,182)	(2,060)	—
Net income	$ 136,171	$ 182,798	$ 230,754	$ 330,103	$ 226,205
Basic and diluted net income per limited partner unit	$ n/a	$ 0.83	$ 1.55	$ 2.21	$ 2.22
Balance Sheet Data:					
Working capital (deficit)[(c)]	$ 13,783	$ (310,087)	$ (15,609)	$ (29,644)	$ (94,571)
Total assets	2,264,995	2,316,508	2,416,931	2,600,708	3,163,148
Long-term debt[(c)]	787,194	518,609	914,536	1,083,485	1,680,004
Owners' equity	1,180,352	1,165,775	1,184,566	1,254,132	1,196,354
Cash Distribution Data:					
Cash distributions declared per MMP unit[(d)]	$ 2.06	$ 2.34	$ 2.55	$ 2.77	$ 2.84
Cash distributions paid per MMP unit[(d)]	$ 1.97	$ 2.29	$ 2.49	$ 2.72	$ 2.84

	Year Ended December 31,				
	2005	2006	2007	2008	2009
	(in thousands, except per unit amounts)				
Other Data:					
Operating margin (loss):					
Petroleum products pipeline system	$250,623	$285,743	$352,715	$426,495	$358,648
Petroleum products terminals	67,237	86,823	85,488	104,121	113,523
Ammonia pipeline system	7,687	2,554	(2,995)	8,660	3,666
Allocated partnership depreciation costs[e]	3,406	3,583	3,032	3,483	3,839
Operating margin	$328,953	$378,703	$438,240	$542,759	$479,676
Adjusted EBITDA:					
Net income	$136,171	$182,798	$230,754	$330,103	$226,475
Provision for income taxes[a]	—	—	1,568	1,987	1,661
Debt prepayment premium	—	—	1,984	—	—
Write-off of unamortized debt placement fees	6,413	—	—	—	—
Debt placement fee amortization	2,247	1,925	1,554	767	1,112
Interest expense, net	52,273	47,624	47,653	50,479	69,187
Depreciation and amortization expense	71,655	76,200	79,140	86,501	97,216
Adjusted EBITDA	$268,759	$308,547	$362,653	$469,837	$395,651
Operating Statistics:					
Petroleum products pipeline system:					
Transportation revenue per barrel shipped	$ 1.025	$ 1.060	$ 1.147	$ 1.193	$ 1.205
Volume shipped (million barrels)[f]	298.6	309.6	307.2	295.9	295.7
Petroleum products terminals:					
Marine terminal average storage utilized (million barrels per month)	20.4	20.9	21.8	23.3	26.2
Inland terminal throughput (million barrels) put (million barrels)	101.3	110.1	117.3	108.1	109.8
Ammonia pipeline system:					
Volume shipped (thousand tons)	713	726	716	822	643

(a) Beginning in 2007, the state of Texas implemented a partnership-level tax based on a percentage of net revenues apportioned to the state of Texas. The estimate of this tax was reported as provision for income taxes on the consolidated statements of income included in this report.

(b) Prior to September 28, 2009, the date the simplification closed, net income allocations were as follows:

- Non-controlling owners' interest was MMP's net income allocated to owners other than MGG;
- Limited partner interests was net income allocated to MGG's limited partner unitholders; and
- General partner interest was the net loss allocated to MGG's general partner.

Following the simplification, the non-controlling owners' interest was eliminated and all of our net income is now allocated to our limited partners, which is a combination of the MMP and MGG pre-simplification unitholders.

(c) The maturity date of our pipeline notes was October 7, 2007. As a result, the $270.8 million carrying value of these notes was classified as a current liability on the December 31, 2006 consolidated balance sheet. This debt was refinanced before its maturity.

(d) 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.

(e) 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.

(f) Excludes capacity leases.

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

Introduction

We are a publicly traded limited partnership formed to own, operate and acquire a diversified portfolio of complementary energy assets. We are principally engaged in the transportation, storage and distribution of refined petroleum products. As of December 31, 2009, our three operating segments included:

- petroleum products pipeline system, which is primarily comprised of our 9,500-mile petroleum products pipeline system, including 51 terminals;
- petroleum products terminals, which principally includes our seven marine terminal facilities and 27 inland terminals; and
- ammonia pipeline system, representing our 1,100-mile ammonia pipeline and six associated terminals.

The following discussion provides an analysis of the results for each of our operating segments, an overview of our liquidity and capital resources and other items related to our partnership. The following discussion and analysis should be read in conjunction with our consolidated financial statements and related notes included in this Annual Report on Form 10-K for the year ended December 31, 2009.

Simplification. In March 2009, we and our general partner and Magellan Midstream Holdings, L.P. ("MGG") and Magellan Midstream Holdings GP, LLC ("MGG GP"), MGG's general partner, entered into an Agreement Relating to Simplification of Capital Structure (the Simplification Agreement and the steps completed pursuant thereto are referred to herein as "the simplification"). Pursuant to the simplification, which was approved by both our and MGG's unitholders on September 25, 2009, we amended and restated our existing partnership agreement to provide for the transformation of the incentive distribution rights and approximate 2% general partner interest owned by Magellan GP, LLC ("MMP GP"), our general partner, into limited partner units representing limited partner interests in us ("new limited partner units") and a non-economic general partner interest in us (the "transformation"). Once the transformation was completed, MMP GP distributed the new limited partner units that it received in the transformation to MGG (the "unit distribution"). Once the unit distribution was completed, pursuant to a Contribution and Assumption Agreement: (i) MGG contributed 100% of its member interests in Magellan Midstream Holdings GP, LLC, its general partner, to MMP GP; (ii) MGG contributed 100% of its member interests in MMP GP to us; (iii) MGG contributed to us all of its cash and assets, other than the new limited partner units it received in the unit distribution; and (iv) we assumed all of MGG's liabilities (collectively, the "contributions"). Once the contributions were completed, MGG distributed the new limited partner units it received in the unit distribution to its unitholders (the "redistribution") and MGG was dissolved.

Pursuant to the simplification, MGG received approximately 39.6 million of our limited partner units in the transformation and unit distribution and each of MGG's unitholders received 0.6325 of our limited partner units in the redistribution for each MGG limited partner unit they owned. As a result, the number of our limited partner units outstanding increased from 67.0 million units to 106.6 million units.

Because the incentive distribution rights were eliminated as part of the simplification, our equity cost of capital is now lower, allowing us to be more competitive for future growth opportunities. The simplification preserves our strong balance sheet and liquidity because it was accomplished entirely with equity. In addition, our public float has increased as a result of the simplification, which may attract a broader investor base.

Although titled Magellan Midstream Partners, L.P., the accompanying financial statements in this Annual Report on Form 10-K were originally the financial statements of MGG prior to the completion of the simplification. The simplification was accounted for in accordance with Accounting Standards Codification ("ASC") 810-10-45, *Consolidation—Overall—Changes in Parent's Ownership Interest in a Subsidiary* and we charged the $13.3 million of costs incurred to complete the simplification to equity during the year ended December 31, 2009.

Our general partner continues to manage us following the simplification and our management team remains unchanged. Additionally, three of the four independent members of MGG's general partner's board of directors have joined our general partner's board of directors. The fourth independent member of MGG's general partner's board of directors, Patrick C. Eilers, was already serving as an independent member of our general partner's board of directors.

Longhorn Pipeline Acquisition. On July 29, 2009, we acquired substantially all of the assets of Longhorn Partners Pipeline, L.P. (which we refer to herein as the "Longhorn acquisition") for $252.3 million plus the fair market value of the linefill of $86.1 million. The Longhorn acquisition primarily included an approximate 700-mile common carrier pipeline system that transports refined petroleum products from Houston to El Paso, Texas and a terminal in El Paso. The El Paso terminal serves local petroleum products demand and distributes product to connecting third-party pipelines for ultimate delivery to markets in Arizona and New Mexico and, in the future, Northern Mexico.

Because the assets included in the Longhorn acquisition had minimal commercial activity following the former owner's 2008 bankruptcy filing, we anticipate a ramp-up of operations through 2012 as a customer base is built for this pipeline system. We are purchasing petroleum products for shipment on this pipeline system which we are selling in the wholesale markets in El Paso, Texas. We will continue these activities until the third-party shipments on this pipeline significantly increase.

Recent Developments

Distribution. During January 2010, the board of directors of our general partner declared a quarterly cash distribution of $0.71 per unit for the period of October 1 through December 31, 2009. The $0.71 per unit distribution was paid on February 12, 2010 to unitholders of record on February 2, 2010. The total distributions paid on 106.7 million limited partner units outstanding was $75.8 million.

Overview

Our petroleum products pipeline system and petroleum products terminals generate the majority of our operating margin from the transportation and storage services we provide to our customers. The revenues generated from these petroleum products businesses are significantly influenced by demand for refined petroleum products. 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 pipeline and stored in our terminals. Expenses resulting from environmental remediation projects include costs from projects relating both to current and past events.

A prolonged period of high refined petroleum product prices or a recessionary economic environment could lead to a reduction in demand and result in lower shipments on our pipeline system and reduced demand for our terminal services. Fluctuations in the prices of refined petroleum products impact the amount of cash our petroleum products pipeline system generates from its petroleum products 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* for other risk factors that could impact our results of operations, financial position and cash flows.

Petroleum Products Pipeline System. Our petroleum products pipeline system is comprised of a common carrier pipeline that provides transportation, storage and distribution services for petroleum products in 13 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 petroleum products pipeline system can access more than 40% of the refinery capacity in the continental United States. In 2009, the pipeline generated 72% of its revenues, excluding the sale of petroleum products, through transportation tariffs for volumes of petroleum products it ships. 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 on a long-term basis and by providing data services and product services such as ethanol and biodiesel unloading and loading, additive injection, custom blending and laboratory testing.

Most of the shipments on our pipeline system are for third parties and we do not take title to these products. We do take title to products related to our petroleum products blending and fractionation activities and in connection with certain transactions involving the operation of our pipeline system and terminals. Further, we own and have title to the linefill of the pipeline acquired in the Longhorn acquisition and we take title to the petroleum products we transport on this pipeline on our own behalf. Although our petroleum products blending, fractionation activities and the other commodity-related activities we conduct generate significant revenues from the sale of petroleum products, we believe the gross margin from these activities, which takes into account the related product purchases, better represents its importance to our results of operations.

Petroleum Products Terminals. Our petroleum products terminals segment is comprised of marine and inland terminals, which store and distribute gasoline and other petroleum products throughout 12 states. Our marine terminals are large storage and distribution terminals that have marine access and in some cases are strategically located near major refining hubs along the U.S. Gulf and East Coasts and principally serve refiners and large end-users of petroleum products. We earn revenues at our marine facilities primarily from storage and throughput fees. Our inland terminals are part of a distribution network located principally throughout the southeastern United States. These inland terminals are connected to large, third-party interstate pipelines and are utilized by retail suppliers, wholesalers and marketers to transfer gasoline and other petroleum products from these pipelines to trucks, railcars or barges for delivery to their final destination. We earn revenues at our inland terminals primarily from fees we charge based on the volumes of refined petroleum products distributed from these locations and from ancillary services such as additive injections.

Ammonia Pipeline System. Our ammonia pipeline system 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.

Acquisitions

We significantly increased our operations during 2009 through the following acquisitions:

- In July 2009, the acquisition of a 700-mile pipeline (the "Longhorn acquisition") for $252.3 million plus the fair market value of associated linefill of $86.1 million;
- In September 2009, the acquisition of a terminal in Oklahoma connected to a refinery that is an origin point on our petroleum products pipeline system for $20.0 million; and
- In October 2009, the acquisition of a facility adjacent to one of our existing marine terminals in Louisiana for $32.2 million.

Growth Projects

We remain focused on growth and have significantly increased our operations over the past several years through organic growth projects that expand or upgrade our existing facilities. Our current expansion projects are driven by:

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

- government regulations for renewable fuels such as ethanol and biodiesel as fuel additives, which require us to add blending infrastructure on which we will earn additional profits. In addition, we continue to assess the feasibility of a dedicated ethanol pipeline; and
- demand for enhanced connectivity to key growth markets, such as Dallas and Houston, Texas. We are constructing storage tanks and building a connection to an existing third-party pipeline in the Houston area to accommodate additional refinery capacity from the Port Arthur, Texas region, supported by a long-term customer agreement. Further, we are in the process of connecting the pipeline acquired in the Longhorn acquisition to our facility at East Houston, Texas.

We spent $480.1 million and $266.1 million on acquisitions and growth projects during 2009 and 2008, respectively. Further, we currently expect to spend approximately $210.0 million in 2010 on projects now underway, with additional spending of approximately $30.0 million expected in 2011 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, product sales and product purchases, are determined in accordance with GAAP.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2009

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2008	**2009**	**$ Change**	**% Change**
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum products pipeline system	$478.5	$494.2	$ 15.7	3
Petroleum products terminals	141.1	169.9	28.8	20
Ammonia pipeline system	22.7	19.9	(2.8)	(12)
Intersegment eliminations	(3.5)	(5.1)	(1.6)	(46)
Total transportation and terminals revenues	638.8	678.9	40.1	6
Affiliate management fee revenues	0.7	0.8	0.1	14
Operating expenses:				
Petroleum products pipeline system	197.7	183.9	13.8	7
Petroleum products terminals	59.1	64.4	(5.3)	(9)
Ammonia pipeline system	14.1	16.2	(2.1)	(15)
Intersegment eliminations	(6.1)	(6.9)	0.8	13
Total operating expenses	264.8	257.6	7.2	3
Product margin:				
Product sales	574.1	334.5	(239.6)	(42)
Product purchases	436.6	280.3	156.3	36
Product margin	137.5	54.2	(83.3)	(61)
Gain on assignment of supply agreement	26.5	—	(26.5)	(100)
Equity earnings	4.1	3.4	(0.7)	(17)
Operating margin	542.8	479.7	(63.1)	(12)
Depreciation and amortization expense	86.5	97.2	(10.7)	(12)
G&A expense	73.3	84.1	(10.8)	(15)
Operating profit	383.0	298.4	(84.6)	(22)
Interest expense (net of interest income and interest capitalized)	50.5	69.2	(18.7)	(37)
Debt placement fee amortization	0.8	1.1	(0.3)	(38)
Other income	(0.4)	(0.1)	(0.3)	(75)
Income before provision for income taxes	332.1	228.2	(103.9)	(31)
Provision for income taxes	2.0	1.7	0.3	15
Net income	$330.1	$226.5	$(103.6)	(31)
Operating Statistics				
Petroleum products pipeline system:				
Transportation revenue per barrel shipped	$1.193	$1.205		
Volume shipped (million barrels)[(a)]	295.9	295.7		
Petroleum products terminals:				
Marine terminal average storage utilized (million barrels per month)	23.3	26.2		
Inland terminal throughput (million barrels)	108.1	109.8		
Ammonia pipeline system:				
Volume shipped (thousand tons)	822	643		

(a) Excludes capacity leases.

Transportation and terminals revenues increased by $40.1 million:

- an increase in petroleum products pipeline system revenues of $15.7 million primarily attributable to higher leased storage and transportation revenues and incremental fees for ethanol blending and additives. The higher leased storage revenues resulted from new storage capacity. Transportation revenues increased primarily as a result of higher average tariffs due largely to the mid-year tariff escalations. Otherwise, an increase in gasoline shipments reflecting the impact of lower gasoline prices during 2009 primarily offset lower diesel and aviation fuel shipments due to the weak economic conditions in 2009;
- an increase in petroleum products terminals revenues of $28.8 million due to higher revenues at both marine and inland terminals. Marine revenues increased primarily at our Galena Park, Texas and Wilmington, Delaware facilities due to leasing new storage tanks placed in service over the past year and higher rates on existing storage. Inland revenues benefitted from higher fees due to ethanol blending and increased throughput volumes; and
- a decrease in ammonia pipeline system revenues of $2.8 million due to lower shipments primarily resulting from operational issues at two of our customers' plants during early 2009 and increased system maintenance and testing during 2009, resulting in the pipeline being unavailable for shipments during that time. The impact of lower volumes on revenues was partially offset by higher average tariffs.

Operating expenses decreased by $7.2 million:

- a decrease in petroleum products pipeline system expenses of $13.8 million due primarily to more favorable product overages (which reduce operating expenses) and lower power costs resulting from lower prices for natural gas and electricity, partially offset by higher operating expenses related to the Longhorn acquisition, additional compensation costs and higher environmental expenses. The 2008 period included a $12.1 million reduction to environmental expenses resulting from the favorable settlement of a civil penalty related to historical product releases;
- an increase in petroleum products terminals expenses of $5.3 million primarily related to higher personnel costs, operating taxes (hurricane damage resulted in lower tax assessments in 2008) and gains recognized from insurance proceeds received in 2008 associated with hurricane damages sustained during 2005; and
- an increase in ammonia pipeline system expenses of $2.1 million due primarily to an increase in system maintenance and testing in 2009.

Product sales revenues primarily resulted from our petroleum products blending activities, product marketing and linefill management associated with the Longhorn acquisition, terminal product gains and transmix fractionation. Product margin decreased $83.3 million primarily because the unrealized losses on New York Mercantile Exchange ("NYMEX") contracts during the current year compare unfavorably to the unrealized gains experienced during 2008 by $48.7 million. Otherwise, product margin decreased $34.6 million primarily reflecting lower fractionation margins and lower margins from the sale of product overages at our petroleum products terminals. The lower product margins and the change in the value of the NYMEX contracts resulted primarily from significantly lower product prices in 2009 compared to 2008.

The 2008 period benefited from a $26.5 million non-cash gain on the assignment of MMP's third-party supply agreement during March 2008. The gain resulted from the write-off of the unamortized amount of a liability MMP recognized related to the fair value of the agreement, which it assumed as part of its acquisition of certain pipeline assets in October 2004.

Depreciation and amortization expense increased by $10.7 million primarily due to expansion capital projects placed into service over the past year.

G&A expense increased by $10.8 million between periods primarily due to higher personnel costs and equity-based incentive compensation costs. Personnel costs were higher due to additional headcount, merit increases and substantially higher bonus accruals. Equity-based incentive compensation costs increased primarily because the expense associated with the final tranche of the 2007 unit awards was recognized over a shorter period than in previous years and because our limited partner unit price increased 43% during 2009.

Interest expense, net of interest income and interest capitalized, increased $18.7 million in 2009. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased to $1.4 billion for 2009 from $1.0 billion for 2008 principally due to borrowings for expansion capital expenditures and the Longhorn acquisition. The weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, decreased to 5.4% in 2009 from 5.7% in 2008.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2008

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2007	2008	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum products pipeline system	$460.7	$478.5	$ 17.8	4
Petroleum products terminals	132.7	141.1	8.4	6
Ammonia pipeline system	18.3	22.7	4.4	24
Intersegment eliminations	(2.9)	(3.5)	(0.6)	(21)
Total transportation and terminals revenues	608.8	638.8	30.0	5
Affiliate management fee revenues	0.7	0.7	—	—
Operating expenses:				
Petroleum products pipeline system	178.9	197.7	(18.8)	(11)
Petroleum products terminals	56.2	59.1	(2.9)	(5)
Ammonia pipeline system	21.3	14.1	7.2	34
Intersegment eliminations	(5.4)	(6.1)	0.7	13
Total operating expenses	251.0	264.8	(13.8)	(6)
Product margin:				
Product sales	709.6	574.1	(135.5)	(19)
Product purchases	633.9	436.6	197.3	31
Product margin	75.7	137.5	61.8	82
Gain on assignment of supply agreement	—	26.5	26.5	N/A
Equity earnings	4.0	4.1	0.1	3
Operating margin	438.2	542.8	104.6	24
Depreciation and amortization expense	79.1	86.5	(7.4)	(9)
G&A expense	74.9	73.3	1.6	2
Operating profit	284.2	383.0	98.8	35
Interest expense (net of interest income and interest capitalized)	47.7	50.5	(2.8)	(6)
Debt placement fee amortization	1.5	0.8	0.7	47
Debt prepayment premium	2.0	—	2.0	100
Other (income) expense	0.6	(0.4)	1.0	167
Income before provision for income taxes	232.4	332.1	99.7	43
Provision for income taxes	1.6	2.0	(0.4)	(25)
Net income	$230.8	$330.1	$ 99.3	43
Operating Statistics				
Petroleum products pipeline system:				
Transportation revenue per barrel shipped	$1.147	$1.193		
Volume shipped (million barrels)[(a)]	307.2	295.9		
Petroleum products terminals:				
Marine terminal average storage utilized (million barrels per month)	21.8	23.3		
Inland terminal throughput (million barrels)	117.3	108.1		
Ammonia pipeline system:				
Volume shipped (thousand tons)	716	822		

(a) Excludes capacity leases.

Transportation and terminals revenues increased by $30.0 million resulting from higher revenues for each of our business segments as shown below:

- an increase in petroleum products pipeline system revenues of $17.8 million. Transportation revenues increased as a result of higher average tariffs due in part to our mid-year 2007 and 2008 tariff escalations, partially offset by shipment disruptions in late 2008 attributable to Hurricane Ike and weak demand for petroleum products as a result of high product prices during most of 2008. We also earned more ancillary revenues related to leased storage, ethanol blending services, capacity leases and facility rentals;
- an increase in petroleum products terminals revenues of $8.4 million. Revenues increased at our marine terminals primarily due to operating results from additional storage tanks at our Galena Park, Texas facility that were placed into service throughout 2007 and 2008. The revenue increase was negatively impacted by lost business due to Hurricane Ike during late 2008. Our inland terminal revenues were essentially flat between periods as higher fees due to ethanol and additive blending offset lower volumes; and
- an increase in ammonia pipeline system revenues of $4.4 million primarily due to additional shipments resulting from favorable weather and market conditions and higher average tariff rates charged.

Operating expenses increased by $13.8 million as higher expenses at our petroleum products pipeline system and petroleum products terminals segments were partially offset by lower costs related to our ammonia pipeline system, as described below:

- an increase in petroleum products pipeline system expenses of $18.8 million primarily due to less favorable product overages (which reduce operating expenses) in 2008, higher system integrity spending and increased environmental accruals for several historical releases. The higher system integrity spending was due to accelerating work into 2008 that was originally planned to occur in 2009. Partially offsetting these items was a $12.1 million reduction to our operating expenses in 2008 due to the favorable settlement of a civil penalty related to historical product releases;
- an increase in petroleum products terminals expenses of $2.9 million primarily related to higher personnel costs and maintenance spending, including clean-up costs related to Hurricane Ike in 2008. These increases were partially offset by gains recognized from insurance proceeds received in 2008 associated with hurricane damages sustained during 2005; and
- a decrease in ammonia pipeline system expenses of $7.2 million primarily due to lower environmental expenses and system integrity costs. Environmental expenses were higher in 2007 due primarily to increased accruals related to a 2004 pipeline release.

Product sales revenues primarily resulted from our petroleum products blending activities, terminal product gains and transmix fractionation. Product sales and product purchases were significantly lower during the 2008 year due to our assignment of a supply agreement during first quarter 2008. Product margin increased $61.8 million primarily due to higher product prices, the sale of additional product overages by our petroleum products terminals and the sale of unprocessed transmix by our petroleum products pipeline segment during 2008. Additionally, a $20.2 million unrealized gain was recorded in 2008 related to changes in the fair value of our NYMEX commodity futures contracts, partially offset by lower-of-average-cost-or-market adjustments of $6.4 million and $3.0 million to our refined petroleum products inventory and transmix inventory, respectively.

The 2008 period benefited from a $26.5 million non-cash gain on the assignment of our third-party supply agreement during March 2008. The gain resulted from the write-off of the unamortized amount of a liability we recognized related to the fair value of the agreement, which we assumed as part of our acquisition of certain pipeline assets in October 2004.

Depreciation and amortization expense increased by $7.4 million primarily due to expansion capital projects placed into service during 2008.

G&A expense decreased by $1.6 million between periods primarily due to lower equity-based incentive compensation expense, lower bonus accruals and lower allocated compensation expense related to payments made by a former affiliate to one of our executive officers. The reduced equity-based incentive compensation expenses resulted from a lower weighted-average fair value for limited partner units awarded to plan participants and lower payout estimates for unvested incentive awards during 2008. Partially offsetting these decreases were increases in personnel, legal and expansion project due diligence costs during 2008.

Interest expense, net of interest income and interest capitalized, increased $2.8 million in 2008. During 2007, interest expense was lower due to amortization of a step-up adjustment associated with our pipeline notes, which we repaid in second-quarter 2007. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased to $995.1 million for the 2008 period from $887.5 million for the 2007 period principally due to borrowings for expansion capital expenditures; however, the weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, decreased to 5.7% in 2008 from 6.7% in 2007.

We incurred debt-refinancing expenses of $2.7 million during the 2007 period with no similar expense in 2008. The expenses for 2007 were associated with the early retirement of our pipeline notes during second quarter 2007, originally due in October 2007, and included a debt prepayment premium of $2.0 million as well as related interest rate hedge settlements of $0.7 million, which were recorded as other expense. Debt placement fee amortization also decreased $0.7 million in 2008 due to debt placement fees being amortized over a significantly longer period of time as a result of new notes being issued to repay our pipeline notes.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $293.3 million, $434.9 million and $269.4 million for the years ended December 31, 2007, 2008 and 2009, respectively.

- The $165.5 million decrease from 2008 to 2009 was primarily attributable to:

  > a $54.3 million decrease in net income, excluding the increase in non-cash depreciation and amortization expense, the $26.5 million non-cash gain on assignment of a third-party supply agreement in 2008 and the $12.1 million non-cash reduction to operating expenses resulting from the 2008 favorable settlement of a civil penalty related to historical product releases on our petroleum products pipeline system;

  > a $131.8 million decrease in cash resulting from a $59.1 million increase in inventory in 2009 versus a $72.7 million decrease in inventory in 2008. The increase in inventory during 2009 is primarily attributable to the increase in Longhorn linefill inventory since the acquisition in 2009. The decrease in inventory during 2008 is principally due to the sale of petroleum products inventory when we assigned our product supply agreement to a third party in March 2008 as well as a significant decrease in product prices during the latter part of 2008; and

  > a $56.2 million decrease in cash resulting from a $31.9 million increase in accounts receivable and other accounts receivable in 2009 versus a $24.3 million decrease in accounts receivable and other accounts receivable in 2008. The increase during 2009 is primarily due to an increase in product prices during late 2009 and timing of payments from our customers. The decrease during 2008 is primarily due to a significant decrease in product prices during the latter part of 2008.

  These decreases were partially offset by:

  > a $32.3 million increase in cash resulting from a $12.9 million increase in accrued product purchases in 2009 versus a $19.4 million decrease in accrued product purchases in 2008 due primarily to the timing of invoices received from suppliers;

- > as a result of the assignment of our product supply agreement to a third party in March 2008, we refunded a deposit to our customer, reducing cash in the 2008 year by $18.5 million;
- > a $10.1 million increase in cash resulting from an $8.4 million increase in accrued payroll and benefits in 2009 versus a $1.7 million decrease in accrued payroll and benefits in 2008 due primarily to higher accrued employee incentive compensation in 2009 ; and
- > a $9.9 million increase in cash resulting from a $17.8 million increase in accrued interest payable in 2009 versus a $7.9 million increase in accrued interest payable in 2008 due primarily to the issuance of $550.0 million of long-term notes during 2009.

- The $142.7 million increase from 2007 to 2008 was primarily attributable to:
  - > a $60.8 million increase in net income, excluding the $26.5 million non-cash gain on assignment of supply agreement and the $12.1 million non-cash reduction to operating expenses resulting from the 2008 favorable settlement of a civil penalty related to historical product releases on our petroleum products pipeline system;
  - > a $101.6 million increase in cash resulting from a $72.7 million decrease in inventory in 2008 versus a $28.9 million increase in inventory in 2007. The decrease in inventory during 2008 is principally due to the sale of petroleum products inventory when we assigned our product supply agreement to a third party in March 2008 as well as a significant decrease in product prices during the latter part of 2008; and
  - > an $11.2 million increase in cash resulting from a $0.3 million decrease in accounts payable in 2008 versus an $11.5 million decrease in accounts payable in 2007 due primarily to the timing of invoices received from vendors and suppliers.

  These increases were partially offset by an $18.5 million decrease in the supply agreement deposit in 2008. As a result of the assignment of our product supply agreement to a third party in March 2008, we refunded this deposit.

Net cash used by investing activities for the years ended December 31, 2007, 2008 and 2009 was $193.7 million, $304.7 million and $604.9 million, respectively. During 2009, we completed the Longhorn acquisition for $252.3 million plus the fair market value of the linefill of $86.1 million. We also acquired a petroleum products terminal in Oklahoma for $20.0 million and a facility adjacent to one of our existing marine terminals in Louisiana for $32.2 million plus related liabilities assumed of $2.2 million. These acquisitions were reported collectively as the acquisitions of businesses. Additionally, capital expenditures in 2009 were $216.7 million, which included $43.3 million for maintenance capital, and $173.4 million for expansion capital. Significant expansion capital expenditures during 2009 and 2008 included new storage tanks at our Wilmington, Delaware and Galena Park, Texas terminals. During 2008, we spent $272.1 million for capital expenditures, which included $46.9 million for maintenance capital and $225.2 million for expansion capital. Additionally, we acquired petroleum products terminals in Iowa and Minnesota and a petroleum products terminal in Texas along with a 76-mile petroleum products pipeline, collectively, for $38.3 million plus related liabilities assumed of $2.6 million. During 2007, we spent $190.2 million for capital expenditures, of which $39.7 million was maintenance capital and $150.5 million was expansion capital. Significant expansion capital expenditures during 2007 included new storage tanks, including new tanks at our Galena Park, Texas terminal, ethanol blending equipment, equipment to comply with ultra low sulfur diesel fuel mandates and additions to delivery racks.

Net cash provided (used) by financing activities for the years ended December 31, 2007, 2008 and 2009 was $(105.6) million, $(93.2) million and $301.7 million, respectively. During 2009, borrowings under proceeds from notes issuances (including net premium) of $568.7 million were used to repay, in total, $454.3 million of borrowings on our revolving credit facility, with the balance used for general purposes, including capital expenditures. Net borrowings on the revolver during 2009, net of repayments, were $31.6 million. Additionally, during 2009, MGG paid cash distributions of $67.5 million to its unitholders, we paid cash distributions of $142.6 million to our unitholders other than MGG during the pre-simplification period, and we paid distributions of $75.7 million during the post-simplification period. During 2008, MGG paid distributions of $82.8 million to its unitholders and we paid distributions of $181.5 million to our unitholders other than MGG. During 2008, proceeds from notes issuances of $250.0 million were used to repay $212.0 million of borrowings on our revolving credit facility, with the balance used for general purposes. Net repayments on the revolver during 2008 were $93.5 million. Cash used during 2007 reflects $67.3 million of distributions by MGG to its unitholders and $165.9 million of distributions we paid to our unitholders other than MGG, partially offset by net borrowings on our revolving credit facility of $143.0 million and proceeds of $248.9 million from a note issuance. A portion of these borrowings was used to repay the $272.6 million remaining balance of our pipeline notes.

The quarterly distribution amount related to fourth quarter 2009 was $0.71 per unit, which was paid in February 2010. If we continue to pay cash distributions at this current level and the number of outstanding limited partner units remains at 106.7 million, total cash distributions of $303.1 million will be paid to our unitholders in 2010.

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 2009, maintenance capital spending was $43.3 million, including $5.3 million of spending that would have been covered by an indemnification settlement with a former affiliate or by insurance. For 2010, we expect to incur maintenance capital expenditures for our existing businesses of approximately $45.0 million.

In addition to maintenance capital expenditures, we also incur expansion capital expenditures at our existing facilities. Expenditures for organic growth projects during 2009 were $173.4 million. We further spent $304.5 million plus assumed liabilities of $2.2 million on acquisitions during 2009 for the Longhorn acquisition (excluding $86.1 million on the related linefill), the acquisition of an Oklahoma petroleum products terminal and certain assets adjacent to one of our existing petroleum products terminals in Louisiana. Based on the progress of expansion projects already underway, we expect to spend approximately $210.0 million of expansion capital during 2010, including acquisitions, with an additional $30.0 million in 2011 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 capital expenditures, 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 or fund organic growth projects.

As of December 31, 2009, total debt reported on our consolidated balance sheet was $1,680.0 million. The difference between this amount and the $1,651.6 million face value of our outstanding debt results from the unamortized portion of various fair value hedges and the unamortized discounts and premiums on debt issuances. At December 31, 2009, maturities of our debt were as follows: $0 in 2010 and 2011; $101.6 million in 2012; $0 in 2013; $250.0 million in 2014; and $1.3 billion thereafter.

Note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives of the associated notes.

Revolving Credit Facility. The total borrowing capacity under the revolving credit facility, which matures in September 2012, is $550.0 million. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. Additionally, a commitment fee is assessed at a rate from 0.05% to 0.125%, depending on our credit ratings. Borrowings under this facility are used for general purposes, including capital expenditures. As of December 31, 2009, $101.6 million was outstanding under this facility and $4.4 million was obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets. As of December 31, 2009, the weighted-average interest rate on borrowings outstanding under this facility was 0.6%.

6.45% Notes due 2014. In May 2004, we sold $250.0 million aggregate principal of 6.45% notes due 2014 in an underwritten public offering. The notes were issued for the discounted price of 99.8%, or $249.5 million. Including the impact of amortizing the gains realized on the hedges associated with these notes, the effective interest rate of these notes is 6.3%.

5.65% Notes due 2016. In October 2004, we issued $250.0 million of 5.65% notes due 2016 in an underwritten public offering. The notes were issued for the discounted price of 99.9%, or $249.7 million. The outstanding principal amount of the notes was increased by $3.5 million and $3.1 million at December 31, 2008 and 2009, respectively, for the unamortized portion of a gain realized upon termination of a related interest rate swap (see *Interest Rate Derivatives*, below). Including the impact of amortizing this gain, as well as gains realized on pre-issuance hedges associated with these notes, the weighted-average interest rate of these notes at December 31, 2009 was 5.7%.

6.40% Notes due 2018. In July 2008, we issued $250.0 million of 6.40% notes due 2018 in an underwritten public offering. The outstanding principal amount of the notes was increased by $11.6 million and $10.4 million at December 31, 2008 and 2009, respectively, for the unamortized portion of gains realized upon termination or discontinuation of hedge accounting treatment of associated interest rate swaps (see *Interest Rate Derivatives*, below). Including the amortization of those gains, the weighted-average interest rate of these notes at December 31, 2009 was 5.9%.

6.55% Notes due 2019. In June and August 2009, we issued $550.0 million of 6.55% notes due 2019 in underwritten public offerings. The notes were issued at a net premium of 103.4%, or $568.7 million. Net proceeds from these offerings, after underwriter discounts of $3.6 million and offering costs of $0.8 million, were $564.3 million. The net proceeds were used to repay, in total, $454.3 million of borrowings outstanding under our revolving credit facility ($338.4 million of which was related to the Longhorn acquisition), with the balance used for general purposes including capital expenditures. In connection with these offerings, we entered into interest rate swap agreements to effectively convert $250.0 million of these notes to floating-rate debt (see *Interest Rate Derivatives*, below). The outstanding principal amount of the notes was decreased by $1.6 million at December 31, 2009 for the fair value of the associated interest rate swap agreements. Including the effect of these swap agreements, the weighted-average interest rate of these notes at December 31, 2009 was 4.6%.

6.40% Notes due 2037. In April 2007, we issued $250.0 million of 6.40% notes due 2037 in an underwritten public offering. The notes were issued for the discounted price of 99.6%, or $248.9 million. Including the impact of amortizing the gains realized on pre-issuance hedges associated with these notes, the effective interest rate of these notes at December 31, 2009 is 6.3%.

The revolving credit facility described above requires us to maintain a specified ratio of consolidated debt to EBITDA (as defined in the agreement) of no greater than 4.75 to 1.00. In addition, the revolving credit facility and the indentures under which our public notes were issued contain covenants that limit our ability to, among other things, incur indebtedness secured by certain liens or encumber our assets, engage in certain sale-leaseback transactions and consolidate, merge or dispose of all or substantially all of our assets. We were in compliance with these covenants as of December 31, 2009. During 2009, the terms of the revolving credit facility were amended to exclude the financial impact of unrealized gains and losses of derivative agreements from the calculation of consolidated debt to EBITDA.

The revolving credit facility and notes described above are senior indebtedness.

Interest Rate Derivatives. We use interest rate derivatives to help manage interest rate risk. As of December 31, 2009, we had the following interest rate swap agreements outstanding:

- In June and August 2009, we entered into a total of $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. We account for these agreements as fair value hedges. These agreements effectively convert $250.0 million of our 6.55% fixed-rate notes to floating-rate debt. Under the terms of the agreements, we receive the 6.55% fixed rate of the notes and pay six-month LIBOR in arrears plus 2.18% for the $150.0 million swaps and 2.34% for the $100.0 million swaps. The agreements terminate in June 2019, which is the maturity date of the related notes. Payments settle in January and July each year. During each period, we record the impact of these swaps based on the forward LIBOR curve. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR will result in an adjustment to our interest expense. These interest rate derivatives contain credit-risk-related contingent features. These contingent features provide that in the event of our default on any obligation of $25.0 million or more or a merger in which our credit rating becomes "materially weaker," which would generally be interpreted as falling below investment grade, the counterparties to our interest rate derivatives agreements could terminate those agreements and require immediate settlement. As of December 31, 2009, the $100.0 million interest rate swaps were in a net liability position of $0.1 million, of which $1.4 million was recorded as other current assets and $1.5 million was recorded as other noncurrent liabilities on our consolidated balance sheet. As of December 31, 2009, the $150.0 million interest rate swaps were in a net gain position of $2.9 million, of which $3.0 million was recorded as other current assets and $0.1 million was recorded as other noncurrent liabilities on our consolidated balance sheet.

The following interest rate derivatives were settled during 2009:

- In July 2008, we entered into a $50.0 million interest rate swap agreement ("Derivative A") to hedge against changes in the fair value of a portion of the $250.0 million of 6.40% notes due 2018. Derivative A effectively converted $50.0 million of those notes from a 6.40% fixed rate to a floating rate of six-month LIBOR plus 1.83%. We originally accounted for Derivative A as a fair value hedge. In December 2008, in order to capture the economic value of Derivative A at that time, we entered into an offsetting derivative, as described below, and discontinued hedge accounting for Derivative A. The $5.4 million fair value of Derivative A at that time was recorded as an increase to long-term debt, which is being amortized over the remaining life of the 6.40% fixed-rate notes due 2018. In December 2009, this swap was terminated and we received cash proceeds of $3.4 million.
- In December 2008, concurrent with the discontinuance of hedge accounting for Derivative A, we entered into an offsetting $50.0 million interest rate swap agreement with a different financial institution pursuant to which we paid a fixed rate of 6.40% and received a floating rate of six-month LIBOR plus 3.23%. We entered into this agreement to offset changes in the fair value of Derivative A, excluding adjustments due to changes in counterparty credit risks. This agreement was not designated as a hedge for accounting purposes. In December 2009, this swap was terminated and we received cash proceeds of $2.0 million.

Credit Ratings. Our corporate credit ratings are BBB by Standard and Poor's and Baa2 by Moody's Investor Services and are not currently on watch for a rating change.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2009 (in millions).

	Total	< 1 year	1-3 years	3-5 years	> 5 years
Long-term debt obligations(1)	$1,651.6	$ —	$101.6	$250.0	$1,300.0
Interest obligations(2)	1,083.4	99.3	198.4	186.8	598.9
Operating lease obligations	21.2	3.1	5.5	3.0	9.6
Pension and postretirement medical obligations	23.0	6.9	4.3	1.3	10.5
Purchase commitments:					
Product purchase commitments(3)	24.2	24.2	—	—	—
Utility purchase commitments	5.9	3.8	1.8	0.3	—
Derivative instruments(4)					
Equity-based incentive awards(5)	17.2	7.5	9.7	—	—
Environmental remediation(6)	15.1	6.4	3.8	2.2	2.7
Capital project purchase obligations	41.3	41.3	—	—	—
Maintenance obligations	26.4	23.4	2.9	0.1	—
Other purchase obligations	1.8	1.2	0.4	0.2	—
Total	$2,911.1	$217.1	$328.4	$443.9	$1,921.7

(1) For purposes of this table, we have assumed that the borrowings under our revolving credit facility as of December 31, 2009 ($101.6 million) will not be repaid until the maturity date of the facility in September 2012.

(2) The interest obligation for borrowings under our variable-rate revolving credit facility assumes the borrowings outstanding at December 31, 2009 will remain outstanding until the maturity date of that facility. The interest obligation for borrowings under our variable-rate revolving credit facility further assumes the weighted-average borrowing rate of the facility at December 31, 2009 of 0.6%.

(3) We have an agreement with a supplier whereby we can purchase up to approximately 400,000 barrels of petroleum products per month until 2013. 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, 2013. 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 are unable to determine what the amounts, if any, of that commitment might be.

(4) As of December 31, 2009, we had entered into interest rate swap agreements with a total notional value of $250.0 million. At December 31, 2009, these interest rate swap agreements were in a net gain position. Because future net cash outflows, if any, under these derivative agreements are uncertain, they have been excluded from this table. Additionally, we have entered into a number of commodity-related derivative contracts associated with the future sale of petroleum products. These contracts require us to make margin deposits with the contract counterparty when the contract is in a loss position. At December 31, 2009, we had made margin deposits of $17.9 million. However, because future deposit requirements, if any, are uncertain, they have been excluded from this table.

(5) Represents the grant date fair value of unit awards accounted for as equity plus the December 31, 2009 fair value of award grants accounted for as liabilities times the estimated payout percentage of the awards at December 31, 2009. Settlements of these awards will differ from these reported amounts primarily due to differences between actual payout percentages and current estimates of payout percentages and changes in our unit price between December 31, 2009 and the vesting dates of the awards.

(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 obligates 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 ($3.2 million as of December 31, 2009) and the estimated timing of these payments. Additionally, this agreement requires 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 ($2.1 million) as of December 31, 2009. 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 ($9.3 million as of December 31, 2009) and the estimated timing of those payments based on project progress to date. In addition to these agreements, we were under contract for certain other remediation matters ($0.5 million at December 31, 2009).

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.

Indemnification Settlement. Prior to May 2004, a former affiliate provided indemnifications to us for assets we had acquired from it. In May 2004, we entered into an agreement with our former affiliate under which our former affiliate agreed to pay us $117.5 million to release it from those indemnification obligations. We have received the entire $117.5 million due under this agreement. As of December 31, 2009, known liabilities related to these indemnifications were estimated to be $23.9 million. Through December 31, 2009, we have spent $68.6 million of the indemnification settlement proceeds for indemnified matters, including $26.4 million of capital costs. We have not reserved the cash received from this indemnity settlement and have used it for various other cash needs, including expansion capital spending.

Ammonia EPA Issue. In February 2007, we received notice from the Department of Justice ("DOJ") that the Environmental Protection Agency ("EPA") had requested the DOJ to initiate a lawsuit alleging violations of Sections 301 and 311 of the Clean Water Act with respect to two releases of anhydrous ammonia from our ammonia pipeline system which was operated by a third party at the time of the releases. In March 2007, we also received a demand from the third-party operator for defense and indemnification. In October 2009, we paid a penalty of $3.7 million to the EPA and agreed to perform certain operational enhancements. Further, we settled the third-party operator defense and indemnification for $0.8 million in December 2009.

Clean Air Act. Section 185 of the Clean Air Act requires each state to assess fees against major stationary emission sources in "severe" or "extreme" non-attainment areas. During 2009, the Texas Commission on Environmental Quality ("TCEQ"), in response to an EPA request, issued proposed rules which, if adopted as proposed, may result in fees assessed against our Galena Park, Texas terminal for the 2008 and 2009 calendar years of up to $8.1 million and $4.8 million, respectively.

In recent guidance, the EPA has indicated that a Section 185 fee program is not necessary for areas that have obtained the ozone standard as demonstrated through three consecutive years of monitoring data. Based on the monitoring data for the Houston/Galveston/Brazoria, Texas area prepared by the TCEQ, which indicates that the area obtained the ozone standard for the past three consecutive years, management believes the mostly likely outcome will be that the EPA will recognize that the area has attained the ozone standard and that no fees will be assessed. However, management believes it is reasonably possible that the TCEQ could adopt its rules as proposed. Management believes that should the TCEQ adopt its proposed rules, because of special circumstances, the fees that would ultimately be assessed against our facility could be substantially reduced from the amounts described above. At December 31, 2009, we had no amounts accrued for this matter.

Other Items

NYMEX Contracts. We began using NYMEX contracts during the third quarter of 2008 as economic hedges against changes in the future price of petroleum products. From the third quarter of 2008 through the second quarter of 2009, none of the NYMEX contracts we entered into qualified as hedges for accounting purposes under ASC 815-30, *Derivatives and Hedging*. Beginning with the third quarter of 2009, because of other agreements that we entered into, some of the NYMEX contracts entered into qualified for hedge accounting treatment. Currently, we have two specific groups of commodities that are being hedged with NYMEX contracts:

- Future sales of petroleum products generated from our blending and fractionation activities:
    - Since July 2009, some of the NYMEX contracts associated with future sales of petroleum products qualified for hedge accounting treatment and have been recorded as cash flow hedges.

The gains and losses resulting from the mark-to-market changes in value of these contracts are not included in product sales revenues in our consolidated statement of income until the petroleum products they are hedging are physically sold. As of December 31, 2009, we had open NYMEX contracts for 0.2 million barrels of petroleum product that qualified for hedge accounting treatment. These contracts mature between January 2010 and April 2010. The change in fair value of these agreements during 2009 was a loss of $1.7 million, which was recorded as energy commodity derivatives contracts and accumulated other comprehensive loss on our consolidated balance sheet. Additionally, we had $5.1 million of losses recognized during 2009 associated with derivative agreements that qualified as hedges when the hedged products were sold and the contracts were settled.

  - Additionally, we had open NYMEX contracts for 0.6 million barrels of petroleum products as of December 31, 2009 that did not qualify for hedge accounting treatment. These contracts mature between January and May 2010. As of December 31, 2009, the unrealized losses associated with these agreements of $0.6 million were recorded as product sales revenues on our consolidated statements of income and energy commodity derivative contracts on our consolidated balance sheet. Additionally, we recognized losses of $23.0 million on NYMEX contracts that did not qualify for hedge accounting treatment that settled during 2009.

- Future commodity sales of linefill and working inventory associated with the Longhorn acquisition:
  - During the third quarter of 2009, we completed the Longhorn acquisition, which included the purchase of 1.1 million barrels of linefill. Subsequent to the acquisition, the linefill and working inventory was increased to 1.3 million barrels. We expect our share of the linefill inventory to decline as third-party shipments increase. Currently, we are uncertain as to the timing of when this might occur.
  - At December 31, 2009, we had open NYMEX contracts covering 1.3 million barrels to hedge against changes in the future price of petroleum products associated with the linefill barrels. Contracts covering 1.1 million barrels mature between January 2010 and August 2010 and contracts covering 0.2 million barrels mature in August 2011. Because these NYMEX contracts do not qualify for hedge accounting treatment, we recognize the period change in fair value of these agreements in our consolidated income statement. As of December 31, 2009, the unrealized losses associated with these agreements were $7.7 million, which was recorded as a decrease in product sales revenues on our consolidated statements of income, and $6.6 million and $1.1 million was recorded as energy commodity derivative contracts and other noncurrent liabilities, respectively, on our consolidated balance sheet. Additionally, we recognized $2.2 million of losses associated with the linefill NYMEX contracts that were settled during 2009 which was recorded as a decrease in product sales revenues on our consolidated income statement.

The following table provides a summary of the mark-to-market gains and losses associated with NYMEX contracts and the accounting period that the gains and losses were recognized in our consolidated statements of income (in millions).

2008	
NYMEX gains associated with physical product sales in 2008	$ 30.7
NYMEX gains associated with physical product sales in 2009	20.2
Total NYMEX gains recorded in 2008	$ 50.9
2009	
NYMEX losses associated with physical product sales in 2009	$(30.3)
NYMEX losses associated with future physical product sales	(8.3)
Total NYMEX losses recorded in 2009	$(38.6)

Ammonia Pipeline Testing. We will be performing extensive hydrostatic testing of our ammonia pipeline system during 2010. Expenditures during 2010 to complete this testing are estimated to be up to $10.0 million or $5.0 million higher than the related costs in 2009. During certain periods of testing, it is anticipated that the pipeline will be unavailable for shipments, resulting in reduced shipment volumes. We are unable to estimate the impact this will have on our revenues because we expect our customer movements before and after the testing to be higher than at historical levels.

Pipeline Tariff Increase. The FERC regulates the rates charged on interstate common carrier pipeline operations primarily through an index methodology, which establishes the maximum amount by which tariffs can be adjusted. Approximately 40% of our tariffs are subject to this indexing methodology while the remaining 60% of the tariffs can be adjusted at our discretion based on competitive factors. The current approved methodology is the annual change in the producer price index for finished goods ("PPI-FG") plus 1.3%. The change for 2008 was 6.3%, and we increased substantially all of our tariffs by 7.6% on July 1, 2009. The preliminary change in PPI-FG for 2009 is approximately negative 2.5%. As a result, we expect to decrease our rates in the 40% of our markets that are subject to the FERC's index methodology by approximately 1.2% in July 2010.

Unrecognized Product Gains. Our petroleum products terminals operations generate product overages and shortages that result from metering inaccuracies, product evaporation or expansion, product releases and product contamination. Most of the contracts we have with our customers state that we bear the risk of loss (or gain) from these conditions. When our petroleum products terminals experience net product shortages, we recognize expense for those losses in the periods in which they occur. When our petroleum products terminals experience net product overages, we have product on hand for which we have no cost basis. Therefore, these net overages are not recognized in our financial statements until the associated barrels are either sold or used to offset product losses. The net unrecognized product overages for our petroleum products terminals operations had a market value of approximately $5.1 million as of December 31, 2009. However, the actual amounts we will recognize in future periods will depend on product prices at the time the associated barrels are either sold or used to offset future product losses.

Resignation of Board Member. George A. O'Brien, Jr., an independent director of our general partner's board of directors, resigned effective November 19, 2009 in order to pursue other interests.

Impact of Inflation

Inflation is a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass through increased costs to our customers in the form of higher fees.

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 and the audit committee 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 all three of our operating segments because: (1) estimated expenditures, which will generally be made over the next one to ten years, are subject to cost fluctuations and could change materially, (2) as remediation work is performed and additional information relative to each specific site becomes known, cost estimates for those sites could change materially, (3) unanticipated third-party liabilities may arise, (4) it is difficult to determine whether or not penalties may be levied by governmental agencies with regard to certain environmental events and, if so, the amounts of such penalties and (5) changes in federal, state and local environmental regulations could significantly increase the amount of our environmental liabilities.

A defined process for project reviews is integrated into our system integrity plan. Specifically, our remediation project managers meet once a year with accounting, operations, legal and other personnel to evaluate, in detail, the known environmental sites associated with each of our operating segments. 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, all known information is utilized in conjunction with professional judgment and experience to determine the appropriate approach to remediation and to assess liabilities. The general remediation 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. The estimated environmental liability accruals are adjusted as necessary. Changes in our environmental liabilities since December 31, 2007 were as follows (in millions):

Balance	2008				Balance	2009		Balance
12-31-07	Accruals	Expenditures	Settlements	Acquisitions	12-31-08	Accruals	Expenditures	12-31-09
$57.8	$9.7	$(16.1)	$(12.1)	$2.5	$41.8	$8.5	$(15.9)	$34.4

During 2008, we settled an environmental matter involving historical releases from our petroleum products pipeline with the EPA for which we had a recorded liability of $17.4 million. As a result of the settlement, we paid a penalty of $5.3 million. The difference of $12.1 million was recorded as a reduction of our environmental liability and as a reduction of operating expense. Otherwise, we increased our environmental liabilities by $9.7 million due to changes in cost estimates associated with historical releases of $6.3 million and accrual increases related to product releases which occurred during 2008 of $3.4 million. Further, we assumed $2.5 million of liabilities associated with acquisitions completed during 2008. Environmental liabilities at December 31, 2008 included $4.5 million of amounts we believed would be reimbursed by insurance carriers.

During 2009, we increased our environmental liability accruals by $8.5 million, of which $3.2 million was due to product releases which occurred during 2009 and $5.3 million related to historical releases. Our environmental liabilities at December 31, 2009 included $3.9 million of amounts we believed would be reimbursed by insurance carriers.

Our environmental liabilities at December 31, 2009 were based on estimates that are subject to change, and any changes to these estimates would impact our results of operations and financial position. For example, if our environmental liabilities increased by 25%, our operating expenses would increase and operating profit and net income would decrease by approximately $8.6 million, which represents a decrease of 3% and 4%, respectively, of our operating profit and net income for 2009 and basic and diluted net income per limited partner unit would have been reduced by approximately $0.15. Such a change would not materially impact our liabilities or equity. Further, the impact of such an increase in environmental costs would likely not affect our liquidity because, even with the increased costs, we would still comply with the covenants of our debt agreements as discussed above under “Liquidity and Capital Resources—Liquidity”.

Depreciation Methods and Estimated Useful Lives of Property, Plant and Equipment

Property, plant and equipment ("PP&E") consist primarily of pipeline, pipeline-related equipment, storage tanks and terminal facility equipment. PP&E are stated at cost except for certain acquired assets which were recorded at fair value on their respective acquisition dates and impaired assets. Impaired assets are recorded at fair value on the last impairment evaluation date for which an adjustment was required. PP&E are depreciated using the straight-line method over the asset's estimated useful life. Depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. Straight-line depreciation results in depreciation expense being recognized evenly over the life of the asset. At December 31, 2008 and 2009, the gross book value of our property, plant and equipment was $2.9 billion and $3.4 billion, respectively, and we recorded depreciation expense of $85.0 million and $95.6 million during 2008 and 2009, respectively. The accounting estimate relative to estimated asset lives is a critical accounting estimate for all three of our operating segments because of the significant asset investments in each segment.

The determination of an asset's estimated useful life takes a number of factors into consideration, including technological change, normal depreciation and actual physical usage. If any of these assumptions subsequently change, the estimated useful life of the asset could change and result in an increase or decrease in depreciation expense. Our terminals, pipelines and related equipment have estimated useful lives of three to 59 years, with a weighted-average asset life of approximately 34 years. If the estimates of our asset lives changed such that the average estimated asset life was reduced from 34 years to 30 years, our depreciation expense for 2009 would have increased and operating profit and net income would have decreased by $12.9 million. This represents a decrease of 4% of our operating profit and 6% of net income for 2009 and basic and diluted net income per limited partner unit would have been reduced by approximately $0.23 each. Such a change would not significantly impact our liabilities or equity. Further, the impact of such an increase in depreciation costs would likely not affect our liquidity because, even with the increased expense, we would still comply with the covenants of our long-term debt agreements as discussed above under "Liquidity and Capital Resources—Liquidity".

Goodwill, Other Intangible Assets and Impairment of Long-Lived Assets

Goodwill and Other Intangibles. At both December 31, 2008 and 2009, we had goodwill of $14.8 million. Goodwill resulting from a business combination is not subject to amortization but is tested 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 as of October 1 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. 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 terminal value. 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 our petroleum products terminals segment. Based on our assessment, we do not believe our goodwill is impaired, and we have not recorded a charge associated with ASC 350 during 2007, 2008 and 2009.

Other Intangibles. At December 31, 2008 and 2009, other intangibles, net of accumulated amortization were $5.5 million and $5.9 million, respectively. All of the other intangibles we have recognized are assets with finite useful lives. Intangible assets with a finite useful life are amortized over the period the asset is expected to contribute directly or indirectly to our future cash flows. Each reporting period, we evaluate the remaining useful lives of our intangible assets to determine whether events and circumstances warrant a revision to the remaining period of amortization. The primary factors we use to evaluate the estimated useful lives of our intangible assets include: (i) our expected use of the asset, (ii) legal, regulatory and contractual provisions and (iii) the effects of demand, competition and other economic factors. Different estimates or expectations used in our evaluations could result in different useful lives assigned to our intangible assets. The weighted-average amortization period of our intangible assets at December 31, 2009 was approximately 7 years.

Impairment of Long-Lived Assets. As prescribed by ASC 360-10-05, *Property, Plant and Equipment—General—Impairment or Disposal of Long-Lived Assets*, we assess 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 assets, 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, an impairment charge is recorded 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 for refined products. The impairment reviews and calculations used in our impairment tests are based on assumptions that are consistent with our business plans and long-term investment decisions.

During 2007, we recorded a $2.2 million impairment of certain sections of the pipeline in Illinois and Missouri (most of which were idle). Impairments recorded during 2008 were insignificant. There were no other impairments recognized during 2007, 2008 or 2009. An estimate as to the sensitivity to earnings for these periods if other assumptions had been used in 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 August 2009, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2009-05, an update to ASC 820-10-35, *Fair Value Measurements*. ASU 2009-05 provides guidance on measuring the fair value of liabilities. The guidance in ASU 2009-05 was effective for the first reporting period, including interim periods, beginning after August 28, 2009. Our adoption of this ASU on September 1, 2009 did not have a material impact on our financial position, results of operations or cash flows.

In June 2009, the FASB issued Statement of Financial Accounting Standards (“SFAS”) No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles*. The new codification supersedes all existing GAAP standards and became the single source of GAAP authoritative literature, effective for financial statements issued for interim and annual periods ending after September 15, 2009.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events (as amended)*. This Statement requires the disclosure of subsequent events to be distinguished between recognized and non-recognized subsequent events. Further, entities are required to include a description of the period through which subsequent events were evaluated. Our adoption of this Standard on June 30, 2009 did not have a material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB issued FASB Staff Position (“FSP”) No. FAS 107-1 and Accounting Principles Board (“APB”) 28-1, *Interim Disclosures About Fair Value of Financial Instruments*. This FSP amends SFAS No. 107 (FASB ASC 825-10) and APB Opinion No. 28: (FASB ASC 270-10) by requiring quarterly as well as annual disclosures of the fair value of all financial instruments. The disclosures are to be in a form that makes it clear whether the fair value and carrying amounts represent assets or liabilities and how the carrying amounts relate to what is reported on the balance sheet. Our adoption of this Standard on June 30, 2009 did not have a material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB issued FSP No. FAS 141(R)-1, *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination that Arise from Contingencies*. This FSP amends and clarifies FASB Statement No. 141 (revised 2007), *Business Combinations*, to address application issues on the initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This FSP was effective for assets or liabilities arising from contingencies in business combinations that occurred following the start of the first fiscal year that begins on or after December 15, 2008. Our adoption of this FSP did not have a material impact on our financial position, results of operations or cash flows.

In December 2008, the FASB issued FSP FAS 132(R)-1, *Employers' Disclosures about Postretirement Benefit Plan Assets*. This FSP expands the disclosure requirements for employer pension plans and other postretirement benefit plans to include factors that are pertinent to an understanding of investment policies and strategies. The additional disclosure requirements include; (i) for annual financial statements, the fair value of each major category of plan assets separately for pension and other postretirement plans, (ii) a narrative description of the basis used to determine the expected long-term rate of return on asset assumption, (iii) information to enable users of financial statements to assess the inputs and valuation techniques used to develop fair value measurements of plan assets at the annual reporting date and (iv) for fair value measurements using unobservable inputs, disclosure of the effect of the measurements on changes in plan assets for the period. This FSP is effective for fiscal years ending after December 15, 2009, with early application permitted. Provisions of this FSP are not required for earlier periods that are presented for comparative purposes. Our adoption of this FSP, which we will make in January 2010, is not expected to have a material impact on our financial position, results of operations or cash flows.

In September 2008, the FASB issued Emerging Issues Task Force ("EITF") No. 08-6 *Equity Method Investment Accounting Considerations*. This EITF required entities to measure their equity method investments initially at cost in accordance with SFAS No. 141(R) *Business Combinations*. Further, the EITF clarified that entities should not separately test an investee's underlying indefinite-lived intangible asset for impairment; however, they are required to recognize other-than-temporary impairments of an equity method investment in accordance with APB No. 18, *The Equity Method of Accounting for Investments in Common Stock*. In addition, entities are required to account for a share issuance by an equity method investee as if the investor had sold a proportionate share of its investment. Any gain or loss to the investor resulting from an investee's share issuance is to be recognized in earnings. This EITF was effective for fiscal years beginning on or after December 15, 2008, and interim periods within those fiscal years, and was to be applied prospectively. Our adoption of this EITF in January 2009 did not have a material impact on our financial position, results of operations or cash flows.

In June 2008, the FASB issued FASB FSP No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities*. This FSP clarified that unvested share-based payment awards that contain nonforfeitable rights to distributions or distribution equivalents, whether paid or unpaid, are participating securities as defined in SFAS No. 128, *Earnings Per Share,* and are to be included in the computation of earnings per unit pursuant to the two-class method. This FSP was effective for financial statements issued after December 15, 2008 and interim periods within those years with prior period earnings per unit data retrospectively adjusted. Our adoption of this EITF in January 2009 did not have a material impact on our financial position, results of operations or cash flows.

In April 2008, the FASB issued FSP No. FAS 142-3, *Determination of the Useful Life of Intangible Assets*. This FSP amended the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, *Goodwill and Other Intangible Assets.* This FSP also expanded the disclosures required for recognized intangible assets. This FSP was effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. Our adoption of this FSP in January 2009 did not have a material impact on our financial position, results of operations or cash flows.

In March 2008, the FASB ratified EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships.* Under EITF No. 07-4, the excess of distributions over earnings and/or excess of earnings over distributions for each period are required to be allocated to the entities' general partner based solely on the general partner's ownership interest at the time. This EITF was effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. Our adoption of this Standard in January 2009 did not have a material impact on our income allocation methodology or our calculation of earnings per unit.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities.* SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* established, among other things, the disclosure requirements for derivative instruments and for hedging activities. SFAS No. 161 amended SFAS No. 133, requiring qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. SFAS No. 161 was effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Our adoption of this Standard in January 2009 did not have a material effect on our financial position, results of operations or cash flows.

In February 2008, the FASB issued FSP No. 157-1, *Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13*. FSP No. 157-1 amends SFAS No. 157, *Fair Value Measurements*, to exclude SFAS No. 13, *Accounting for Leases*, and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under Statement 13. However, this scope exception did not apply to assets acquired and liabilities assumed in a business combination that are required to be measured at fair value under SFAS No. 141(R), *Business Combinations*, or SFAS No. 141 (revised 2007), *Business Combinations*, regardless of whether those assets and liabilities are related to leases. This FSP was effective with the initial adoption of SFAS No. 157, which we adopted on January 1, 2007. Our adoption of this FSP did not have a material effect on our financial position, results of operations or cash flows.

Related Party Transactions

We own a 50% interest in a crude oil pipeline company and are paid a management fee for its operation. We received operating fees from this company of \$0.7 million, \$0.7 million and \$0.8 million in 2007, 2008 and 2009, respectively. These fees were reported as affiliate management fee revenue on our consolidated statements of income.

Prior to the simplification, under a services agreement between MGG, MGG GP and us, we and MGG reimbursed MGG GP for the costs of employees necessary to conduct their respective operations and administrative functions. As part of the simplification, MGG GP became our wholly-owned subsidiary; therefore, effective September 28, 2009, we no longer report transactions between us and MGG GP as affiliate transactions. The payroll and benefits accrual associated with the aforementioned agreement at December 31, 2008 was \$21.9 million and the long-term pension and benefits accrual at December 31, 2008 was \$31.8 million.

MGG historically reimbursed us for G&A expenses, excluding equity-based compensation, in excess of a G&A cap. The amount of G&A costs required to be reimbursed was \$4.1 million and \$1.6 million in 2007 and 2008, respectively. MGG Midstream Holdings, L.P. ("MGG MH"), the former owner of MGG, reimbursed MGG for the same amounts MGG reimbursed to us for these excess G&A expenses. We and MGG recorded these reimbursements as a capital contribution from our respective general partners. No reimbursements were made under this agreement after 2008.

During 2007 and 2008, MMP and MGG were allocated \$2.1 million and \$0.4 million, respectively, of non-cash G&A compensation expense, with a corresponding increase in owners' equity, for payments made by MGG MH to one of MMP's executive officers.

The following table summarizes affiliate costs and expenses that are reflected in the accompanying consolidated statements of income (in thousands):

	Year Ended December 31,		
	2007	2008	2009
MGG GP—allocated operating expenses	$81,184	$84,460	$69,523
MGG GP—allocated G&A expenses	46,195	44,482	41,890
MGG MH—allocated G&A expenses	2,149	440	—

Other Related Party Transactions

Because historical distributions paid by Magellan Midstream Partners, L.P. prior to the simplification exceeded target levels as specified in its partnership agreement, MMP GP received approximately 50%, including its approximate 2% general partner interest, of any incremental cash distributed per Magellan Midstream Partners, L.P. limited partner unit. Since MGG owned MMP GP during that period, it benefitted from these distributions. In 2007, 2008 and prior to the simplification in September 2009, distributions paid to MMP GP by Magellan Midstream Partners, L.P. based on MMP GP's general partner interest and incentive distribution rights totaled $70.3 million, $85.6 million and $70.4 million, respectively. Until December 3, 2008, the executive officers of MGG's general partner collectively owned a direct interest in MGG MH of approximately 4% (MGG MH owned MGG's general partner until December 3, 2008). The executive officers of MGG's general partner, through their ownership in MGG MH, indirectly benefited from Magellan Midstream Partners, L.P.'s distributions and directly benefited from MGG's distributions. As of December 31, 2009, our executive officers own less than 1% of our limited partner units.

Forward-Looking Statements

Certain matters discussed in this Annual Report on Form 10-K include forward-looking statements that discuss our expected future results based on current and pending business operations. Forward-looking statements can be identified by words such as "anticipates," "believes," "expects," "estimates," "forecasts," "projects," "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 subject to numerous assumptions, uncertainties and risks that are difficult to predict. Therefore, actual outcomes and results may be materially different from the results stated or implied in such forward-looking statements included in this report.

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

- overall demand for refined petroleum products, natural gas liquids, crude oil and ammonia in the United States;
- price fluctuations for refined petroleum products and natural gas liquids and expectations about future prices for these products;
- changes in general economic conditions, interest rates and price levels in the United States;
- changes in the financial condition of our customers;
- 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 and maintain adequate liquidity;
- development of alternative energy sources, increased use of biofuels such as ethanol and biodiesel, increased conservation or fuel efficiency, regulatory developments or other trends that could affect demand for our services;

- changes in the throughput or interruption in service on petroleum products pipelines owned and operated by third parties and connected to our assets;
- changes in demand for storage in our petroleum products terminals;
- changes in supply patterns for our marine 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 United States Surface Transportation Board and state regulatory agencies;
- shut-downs or cutbacks at major refineries, petrochemical plants, ammonia production facilities or other businesses that use or supply our services;
- weather patterns materially different than historical trends;
- an increase in the competition our operations encounter;
- the occurrence of natural disasters, terrorism, operational hazards 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;
- our ability to identify growth projects or to complete identified growth projects on time and at projected costs;
- our ability to make and integrate acquisitions and successfully complete our business strategy;
- changes in laws and regulations to which we are subject, including tax withholding issues, safety, environmental and employment laws and regulations;
- 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 and the impact these could have on our unit price;
- the ability of third parties to perform on their contractual obligations to us;
- supply disruption; and
- global and domestic economic repercussions from terrorist activities and the government's response thereto.

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

ITEM 7A. *Quantitative and Qualitative Disclosures about Market Risk*

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

Commodity Price Risk

We use derivatives to help us manage product purchases and sales. Derivatives that qualify for and are designated as normal purchases and sales are accounted for using traditional accrual accounting. As of December 31, 2009, we had commitments under forward purchase contracts for product purchases of approximately 0.2 million barrels that are being accounted for as normal purchases totaling approximately $22.4 million, and we had commitments under forward sales contracts for product sales of approximately 0.5 million barrels that are being accounted for as normal sales totaling approximately $45.6 million.

We began using NYMEX contracts during the third quarter of 2008 as economic hedges against changes in the price of petroleum products we expected to sell from our petroleum products blending activities. From the third quarter of 2008 through the second quarter of 2009, none of the NYMEX contracts we entered into qualified for hedge accounting treatment under ASC 815-30, *Derivatives and Hedging*. However, beginning in July 2009, because of other agreements that we entered into, some of the NYMEX contracts associated with our petroleum products blending activities qualified for hedge accounting treatment and have been recorded as cash flow hedges. Additionally, we began using NYMEX contracts during the third quarter of 2009 as economic hedges against changes in the price of petroleum products we expected to sell from the management of our linefill inventory related to the pipeline we purchased with the Longhorn acquisition. At December 31, 2009, the fair value of all open NYMEX contracts, representing 2.1 million barrels of petroleum products, was a net liability of $10.4 million, of which $9.3 million was recorded as energy commodity derivative contracts and $1.1 million was recorded as noncurrent liabilities on our consolidated balance sheet. These open NYMEX contracts mature between January 2010 and August 2011. At December 31, 2009, we had made margin deposits of $17.9 million for these contracts, which we recorded as energy commodity derivatives deposit on our consolidated balance sheet. We have the right to offset the fair value of our open NYMEX contracts against our margin deposits under a master netting arrangement with our counterpart; however, we have elected to separately disclose these amounts on our consolidated balance sheet.

Based on our open NYMEX contracts at December 31, 2009, a $1.00 per barrel increase in the price of the NYMEX contract for reformulated gasoline blendstock for oxygen blending (“RBOB”) gasoline would result in a $2.1 million decrease in our product sales revenues and a $1.00 per barrel decrease in the price of the NYMEX contract for RBOB would result in a $2.1 million increase in our product sales revenues. However, the increases or decreases in product sales revenues we recognize from our open NYMEX contracts are substantially offset by higher or lower product sales revenues when the physical sale of the product occurs. These contracts may be for the purchase or sale of product in markets different from those in which we are attempting to hedge our exposure, resulting in hedges that do not eliminate all price risks.

Interest Rate Risk

During 2009, we entered into a total of $250.0 million of interest rate swap agreements to hedge against changes in the fair value of a portion of our $550.0 million of 6.55% notes due 2019. We account for these agreements as fair value hedges. These agreements effectively convert $250.0 million of our 6.55% fixed-rate notes issued in June and August 2009 to floating-rate debt. Under the terms of the agreements, we will receive the 6.55% fixed rate of the notes and pay six-month LIBOR in arrears plus 2.18% on $150.0 million of the agreements and pay six-month LIBOR in arrears plus 2.34% on the other $100.0 million. The agreements terminate in June 2019, which is the maturity date of the related notes. Payments will settle in January and July each year. During each period, we will record the impact of these swaps based on the forward LIBOR curve. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR will result in an adjustment to interest expense. A 0.125% change in LIBOR would result in an annual adjustment to our interest expense of $0.3 million associated with these hedges.

As of December 31, 2009, we had $101.6 million outstanding on our variable rate revolving credit facility. Considering the amount outstanding on our revolving credit facility as of December 31, 2009, our annual interest expense would change by $0.1 million if LIBOR were to change by 0.125%.

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, 2009 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, 2009, 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, 2009 based on COSO criteria.

Ernst & Young LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2009. The report, which expresses an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2009, is included herein under the heading "Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting."

By: /s/ DON R. WELLENDORF

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, Treasurer 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, 2009, 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, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Magellan Midstream Partners, L.P. as of December 31, 2009 and 2008, and the related consolidated statements of income, owners' equity, and cash flows for each of the three years in the period ended December 31, 2009 and our report dated February 24, 2010 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Tulsa, Oklahoma
February 24, 2010

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, 2009 and 2008, and the related consolidated statements of income, owners' equity, and cash flows for each of the three years in the period ended December 31, 2009. 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 policies used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

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, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, 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, 2009, 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 24, 2010 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Tulsa, Oklahoma
February 24, 2010

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

	Year Ended December 31,		
	2007	**2008**	**2009**
Transportation and terminals revenues	$ 608,781	$ 638,810	$ 678,945
Product sales revenues	709,564	574,095	334,465
Affiliate management fee revenue	712	733	761
Total revenues	1,319,057	1,213,638	1,014,171
Costs and expenses:			
Operating	250,935	264,871	257,635
Product purchases	633,909	436,567	280,291
Depreciation and amortization	79,140	86,501	97,216
General and administrative	74,859	73,302	84,049
Total costs and expenses	1,038,843	861,241	719,191
Gain on assignment of supply agreement	—	26,492	—
Equity earnings	4,027	4,067	3,431
Operating profit	284,241	382,956	298,411
Interest expense	54,956	56,764	73,357
Interest income	(2,851)	(1,482)	(660)
Interest capitalized	(4,452)	(4,803)	(3,510)
Debt placement fee amortization	1,554	767	1,112
Debt prepayment premium	1,984	—	—
Other (income) expense	728	(380)	(24)
Income before provision for income taxes	232,322	332,090	228,136
Provision for income taxes	1,568	1,987	1,661
Net income	$ 230,754	$ 330,103	$ 226,475
Allocation of net income:			
Noncontrolling owners' interests	$ 175,356	$ 244,430	$ 99,729
Limited partners' interest	61,580	87,733	126,746
General partner's interest	(6,182)	(2,060)	—
Net income	$ 230,754	$ 330,103	$ 226,475
Basic and diluted net income per limited partner unit	$ 1.55	$ 2.21	$ 2.22
Weighted average number of limited partner units outstanding used for basic net income per unit calculation	39,626	39,630	57,115
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation	39,626	39,630	57,145

See notes to consolidated financial statements.

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

	December 31, 2008	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 37,912	$ 4,168
Accounts receivable (less allowance for doubtful accounts of $462 and $139 at December 31, 2008 and 2009, respectively)	37,517	72,978
Other accounts receivable	11,805	8,216
Inventory	47,734	193,001
Energy commodity derivative contracts	20,200	—
Energy commodity derivatives deposit	—	17,943
Reimbursable costs	8,176	13,280
Other current assets	7,297	14,382
Total current assets	170,641	323,968
Property, plant and equipment	2,890,672	3,398,606
Less: accumulated depreciation	529,356	617,989
Net property, plant and equipment	2,361,316	2,780,617
Equity investments	23,190	22,054
Long-term receivables	7,390	618
Goodwill	14,766	14,766
Other intangibles (less accumulated amortization of $8,290 and $9,974 at December 31, 2008 and 2009, respectively)	5,539	5,896
Debt placement costs (less accumulated amortization of $2,937 and $4,038 at December 31, 2008 and 2009, respectively)	7,649	10,894
Other noncurrent assets	10,217	4,335
Total assets	$2,600,708	$3,163,148
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable	$ 40,051	$ 37,063
Accrued payroll and benefits	21,884	30,300
Accrued interest payable	15,077	32,877
Accrued taxes other than income	20,151	21,261
Environmental liabilities	19,634	11,943
Deferred revenue	21,492	27,776
Accrued product purchases	23,874	36,797
Energy commodity derivatives contracts	—	9,257
Energy commodity derivatives deposits	18,994	—
Other current liabilities	19,128	22,123
Total current liabilities	200,285	229,397
Long-term debt	1,083,485	1,680,004
Long-term pension and benefits	31,787	22,582
Other noncurrent liabilities	8,853	12,317
Environmental liabilities	22,166	22,494
Commitments and contingencies		
Owners' equity:		
Partners' capital:		
Limited partner unitholders (39,624 units and 106,588 units outstanding at December 31, 2008 and 2009)	68,063	1,204,355
Accumulated other comprehensive loss	(340)	(8,001)
Total partners' capital	67,723	1,196,354
Non-controlling owners' interests in consolidated subsidiaries	1,186,409	—
Total owners' equity	1,254,132	1,196,354
Total liabilities and owners' equity	$2,600,708	$3,163,148

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2007	2008	2009
Operating Activities:			
Net income	$ 230,754	$ 330,103	$ 226,475
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	79,140	86,501	97,216
Debt placement fee amortization	1,554	767	1,112
Debt prepayment premium	1,984	—	—
Loss on sale and retirement of assets	8,548	7,180	5,529
Equity earnings	(4,027)	(4,067)	(3,431)
Distributions from equity investment	3,800	4,067	3,431
Equity-based incentive compensation expense	9,994	4,751	9,622
Pension settlement expense and amortization of prior service cost (credit) and net actuarial loss	1,833	(88)	1,256
Gain on assignment of supply agreement	—	(26,492)	—
Changes in components of operating assets and liabilities (Note 5)	(40,315)	32,167	(71,773)
Net cash provided by operating activities	293,265	434,889	269,437
Investing Activities:			
Property, plant and equipment:			
Additions to property, plant and equipment	(190,182)	(272,083)	(216,698)
Proceeds from sale of assets	961	3,862	338
Changes in accounts payable	(4,434)	661	921
Acquisitions of businesses	—	(38,302)	(390,606)
Distributions in excess of equity investment earnings	—	1,133	1,127
Net cash used by investing activities	(193,655)	(304,729)	(604,918)
Financing Activities:			
Distributions paid	(233,127)	(264,310)	(285,758)
Net borrowings (payments) under revolver	143,000	(93,500)	31,600
Borrowings under notes	248,900	249,980	568,699
Payments on notes	(272,555)	—	—
Debt placement costs	(2,683)	(2,048)	(4,357)
Payment of debt prepayment premium	(1,984)	—	—
Net receipt from financial derivatives	4,556	10,312	5,335
Capital contributions by affiliate	5,218	3,709	—
Increase in outstanding checks	3,026	2,671	2,955
Settlement of tax withholdings on long-term incentive compensation	—	—	(3,450)
Costs associated with the simplification of capital structure	—	—	(13,287)
Net cash (used) provided by financing activities	(105,649)	(93,186)	301,737
Change in cash and cash equivalents	(6,039)	36,974	(33,744)
Cash and cash equivalents at beginning of period	6,977	938	37,912
Cash and cash equivalents at end of period	$ 938	$ 37,912	$ 4,168
Supplemental non-cash financing activity:			
Issuance of MMP limited partner units in settlement of our long-term incentive plan awards	$ 7,406	$ 8,536	$ 1,943

See notes to consolidated financial statements.

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

	Partners' Capital				
	Limited Partners	General Partner	Partners' Accumulated Other Comprehensive Loss	Non-controlling Owners' Interest	Total Owners' Equity
Balance, January 1, 2007	$ 47,541	$ 13,478	$ (201)	$ 1,104,957	$1,165,775
Comprehensive income:					
Net income (loss)	61,580	(6,182)	—	175,356	230,754
Net gain on cash flow hedges	—	—	100	4,918	5,018
Reclassification of net gain on interest rate cash flow hedges to interest expense	—	—	(8)	(411)	(419)
Pension settlement expense and amortization of prior service cost and net actuarial loss	—	—	37	1,796	1,833
Adjustment to recognize the funded status of postretirement plans	—	—	(19)	(920)	(939)
Total comprehensive income (loss)	61,580	(6,182)	110	180,739	236,247
Affiliate capital contributions	—	5,218	—	—	5,218
Distributions	(67,252)	(9)	—	(165,866)	(233,127)
Issuance of MMP limited partner units in settlement of MMP's long-term incentive plan awards	—	—	—	7,406	7,406
Equity method incentive compensation expense	3,076	—	—	—	3,076
Other	(29)	—	—	—	(29)
Balance, December 31, 2007	44,916	12,505	(91)	1,127,236	1,184,566
Comprehensive income:					
Net income (loss)	87,733	(2,060)	—	244,430	330,103
Reclassification of net gain on interest rate cash flow hedges to interest expense	—	—	(3)	(161)	(164)
Amortization of prior service credit and net actuarial loss	—	—	(2)	(86)	(88)
Adjustment to recognize the funded status of postretirement plans	—	—	(244)	(12,028)	(12,272)
Total comprehensive income (loss)	87,733	(2,060)	(249)	232,155	317,579
Affiliate capital contributions	—	3,709	—	—	3,709
Distributions	(82,756)	(12)	—	(181,542)	(264,310)
Equity method incentive compensation expense	4,138	—	—	—	4,138
Issuance of MMP limited partner units in settlement of MMP's long-term incentive plan awards	—	—	—	8,536	8,536
Acquisition of general partner	14,142	(14,142)	—	—	—
Other	(110)	—	—	24	(86)
Balance, December 31, 2008	68,063	—	(340)	1,186,409	1,254,132
Comprehensive income:					
Net income	126,746	—	—	99,729	226,475
Net gain (loss) on cash flow hedges	—	—	(7,430)	626	(6,804)
Reclassification of net gain on interest rate cash flow hedges to interest expense	—	—	(44)	(120)	(164)
Reclassification of net gain (loss) on commodity hedges to product sales revenues	—	—	5,308	(250)	5,058
Amortization of prior service cost and net actuarial loss	—	—	333	923	1,256
Adjustment to recognize the funded status of postretirement plans	—	—	9,259	512	9,771
Total comprehensive income	126,746	—	7,426	101,420	235,592
Distributions	(143,147)	—	—	(142,611)	(285,758)
Equity method incentive compensation expense	6,894	—	—	—	6,894
Costs associated with the simplification of capital structure	(13,287)	—	—	—	(13,287)
Issuance of MMP limited partner units in settlement of long-term incentive plan awards	(4,406)	—	—	6,349	1,943
Issuance of MMP limited partner units in settlement of special unit awards	377	—	—	—	377
Settlement of tax withholdings on long-term incentive compensation	(3,450)	—	—	—	(3,450)
Issuance of MMP limited partner units pursuant to the simplification	1,166,654	—	(15,087)	(1,151,567)	—
Other	(89)	—	—	—	(89)
Balance, December 31, 2009	$1,204,355	$ —	$ (8,001)	$ —	$1,196,354

See notes to consolidated financial statements.

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

1. Basis of Presentation

These financial statements were originally the financial statements of Magellan Midstream Holdings, L.P. ("Holdings") prior to the effective date of the simplification of our capital structure (see Note 2—Simplification below). The simplification was accounted for in accordance with Accounting Standards Codification ("ASC") 810-10-45; Paragraphs 22 and 23, *Consolidation—Overall—Changes in Parent's Ownership Interest in a Subsidiary*. Under ASC 810, the exchange of Holdings' limited partner units for Magellan Midstream Partners, L.P. ("Partners") limited partner units was accounted for as a Holdings equity issuance and Holdings was the surviving entity for accounting purposes. Although Holdings was the surviving entity for accounting purposes, Partners was the surviving entity for legal purposes; consequently, the name on these financial statements was changed from "Magellan Midstream Holdings, L.P." to "Magellan Midstream Partners, L.P."

Historically, Holdings' sole ownership of Partners' general partner, Magellan GP, LLC ("Partners GP"), provided Holdings with an indirect approximate 2% general partner interest in Partners. Holdings' ownership of Partners' general partner interest gave it control of Partners as the limited partner interests of Partners (i) did not have the substantive ability to dissolve Partners, (ii) could remove Partners GP as Partners' general partner only with a supermajority vote of Partners' limited partner units, with certain restrictions on the number of units that could be voted in such an election, and (iii) did not possess substantive participating rights in Partners' operations. As a result, Holdings' consolidated financial statements included the assets, liabilities and cash flows of Partners and Partners GP.

During the periods that Holdings controlled Partners, Holdings had no substantial assets and liabilities other than those of Partners. Holdings' consolidated balance sheet included non-controlling owners' interests of consolidated subsidiaries, which reflected the proportion of Partners that was not owned by Holdings. In addition, Holdings' consolidated balance sheet reflected fair value adjustments to approximately 55% of the historical values reported on Partners' consolidated balance sheet.

The reconciliation of Partners' net income, as historically reported, to the net income reported in these financial statements is as follows (in thousands):

	Year Ended December 31, 2007	Year Ended December 31, 2008
Net income, as previously reported	$242,790	$346,613
Adjustments:		
Depreciation expense[(a)]	(15,348)	(15,348)
Other[(b)]	3,312	(1,162)
Net income	$230,754	$330,103

(a) Holdings acquired 54.6% of general and limited partner interests in Partners on June 17, 2003. At that time, Holdings recorded Partners' property, plant and equipment at 54.6% of their fair values and at 45.4% of their historical carrying values reflecting Holdings' ownership percentages in Partners at that time. As a result of this "step-up" in basis, Holdings recorded higher depreciation expense than Partners.

(b) Other adjustments in 2008 and 2007 included the amortization of the step-up to fair value made by Holdings on June 17, 2003 of other items, including the fair value of Partners' debt and certain commercial contracts, and stand-alone G&A expenses that Holdings incurred. Other adjustments in 2007 also included interest income recognized related to an indemnification settlement with a former affiliate.

Because of the changes the simplification has had on these financial statements and our organizational structure, and because the nature of the pre-simplification and post-simplification entities are significantly different, management believes it is important to clearly distinguish between the pre-simplification and post-simplification organization. Therefore, these notes to consolidated financial statements refer to Magellan

Midstream Partners, L.P. prior to the simplification as "Partners;" Magellan GP, LLC as "Partners GP;" Magellan Midstream Holdings, L.P. as "Holdings;" and Magellan Midstream Holdings GP, LLC as "Holdings GP." Unless specified elsewhere, the terms "we," "our," "us" and similar language refer to Magellan Midstream Partners, L.P., together with its subsidiaries, after the simplification.

2. Simplification

In March 2009, Partners, Partners GP, Holdings and Holdings GP entered into an Agreement Relating to Simplification of Capital Structure (the Simplification Agreement and the steps completed pursuant thereto are referred to herein as "the simplification"). Pursuant to the simplification, which was approved by both Partners' and Holdings' unitholders on September 25, 2009, Partners amended and restated its existing partnership agreement to provide for the transformation of the incentive distribution rights and approximate 2% general partner interest owned by Partners GP into limited partner units representing limited partner interests in Partners ("new limited partner units") and a non-economic general partner interest (the "transformation"). Once the transformation was completed, Partners GP distributed the new limited partner units that it received in the transformation to Holdings (the "unit distribution"). Once the unit distribution was completed, pursuant to a Contribution and Assumption Agreement: (i) Holdings contributed 100% of its member interests in Holdings GP, its general partner, to Partners GP; (ii) Holdings contributed 100% of its member interests in Partners GP to Partners; (iii) Holdings contributed to Partners all of its cash and assets, other than the new limited partner units it received in the unit distribution; and (iv) Partners assumed all of Holdings' liabilities (collectively, the "contributions"). Once the contributions were completed, Holdings distributed the new limited partner units it received in the unit distribution to its unitholders (the "redistribution") and Holdings was dissolved. The transformation of the general partner interest and incentive distribution rights into the new limited partner units occurred on September 28, 2009.

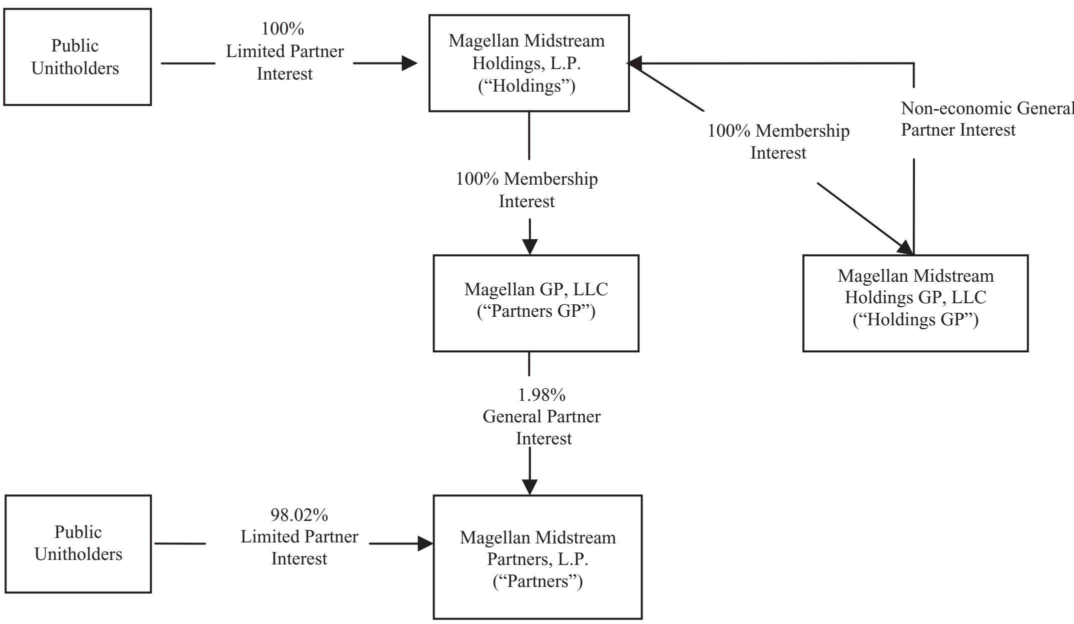
Pursuant to the simplification, Holdings received approximately 39.6 million of Partners' limited partner units in the transformation and unit distribution and each of Holdings' unitholders received 0.6325 of Partners limited partner units in the redistribution for each Holdings limited partner unit they owned. As a result, the number of Partners limited partner units outstanding increased from 67.0 million to 106.6 million. However, for historical reporting purposes, the impact of this change was accounted for as a reverse unit split of 0.6325 to 1.0. Therefore, since Holdings was the surviving reporting entity, the weighted average limited partner units outstanding used for basic and diluted earnings per unit calculations are Holdings' historical weighted average limited partner units outstanding adjusted for the retrospective application of the reverse unit split. Amounts reflecting historical Holdings limited partner unit and per limited partner unit amounts included in this report have been restated for the reverse unit split.

Our general partner continues to manage us following the simplification and our management team remains unchanged. Additionally, three of the four independent members of Holdings GP's board of directors joined our general partner's board of directors. The fourth independent member of Holdings GP's board of directors, Patrick C. Eilers, was already serving as an independent member of our general partner's board of directors.

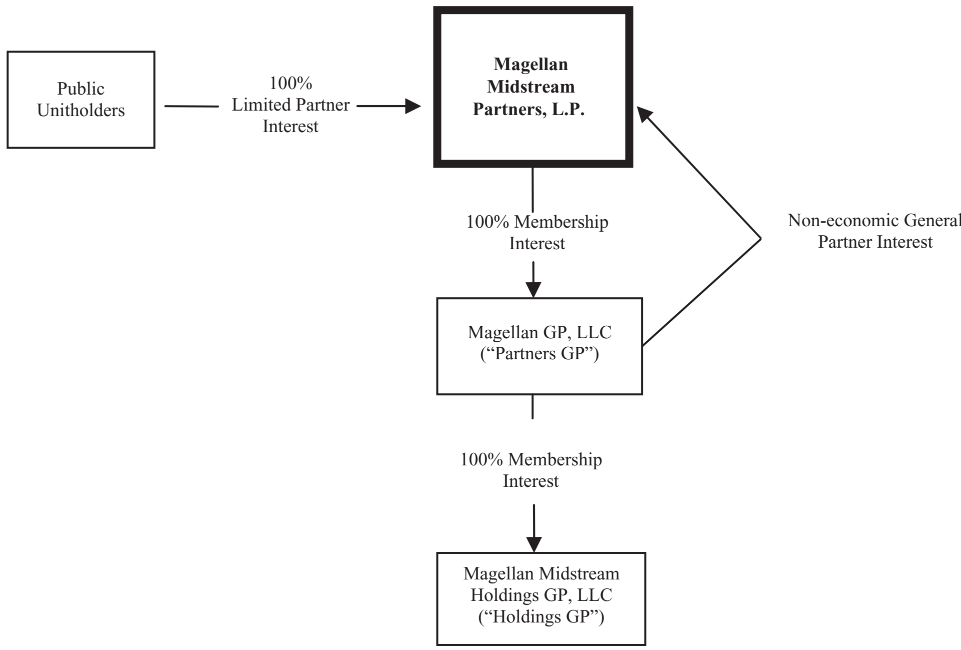
During the year ended December 31, 2009, we incurred $13.3 million of costs associated with the simplification. In accordance with ASC 810-10-45, *Consolidation—Overall—Changes in Parent's Ownership Interest in a Subsidiary*, these costs were charged to equity. These costs are reported under the caption "Costs associated with the simplification of capital structure" in the financing activities section of our consolidated statements of cash flows.

3. Organization

We are a Delaware limited partnership, and our limited partner units are traded on the New York Stock Exchange under the ticker symbol "MMP." Partners GP, a Delaware limited liability company, serves as our general partner and is a wholly-owned subsidiary of ours. Prior to the simplification, Partners and Partners GP contracted with Holdings GP to provide all general and administrative ("G&A") services and operating functions required for Partners' operations. Prior to the simplification, Partners' organizational structure and that of its affiliate entities, as well as how we refer to these affiliates in these notes to consolidated financial statements, was as follows:



The simplification (see Note 2—Simplification) was approved by Partners' and Holdings' unitholders; therefore, effective September 28, 2009, our organizational structure became as follows:



Operating Segments

We own a petroleum products pipeline system, petroleum products terminals and an ammonia pipeline system. Our reportable segments offer different products and services and are managed separately because each requires different marketing strategies and business knowledge.

Petroleum Products Pipeline System. Our petroleum products pipeline system includes approximately 9,500 miles of pipeline and 51 terminals that provide transportation, storage and distribution services. Our petroleum products pipeline system covers a 13-state area extending from Texas through the Midwest to Colorado, North Dakota, Minnesota, Wisconsin and Illinois. The products transported on our pipeline system are primarily gasoline, distillates, LPGs and aviation fuels. Product originates on the system from direct connections to refineries and interconnects with other interstate pipelines for transportation and ultimate distribution to retail gasoline stations, truck stops, railroads, airports and other end-users. We have a 50% interest in a crude oil pipeline company that owns a 135-mile pipeline that transports crude oil from Cushing, Oklahoma to El Dorado, Kansas and has connections to National Cooperative Refining Association's refinery in McPherson, Kansas and the Frontier refinery in El Dorado, Kansas. Our petroleum products blending and fractionation activities are also included in the petroleum products pipeline system segment.

During 2009, Partners acquired substantially all of the assets of Longhorn Partners Pipeline, L.P. (referred to as the "Longhorn acquisition") for $252.3 million plus the fair market value of the linefill of $86.1 million. Partners also acquired a terminal in Oklahoma during 2009 for $20.0 million. The operating results from these acquisitions have been included in our petroleum products pipeline system segment's results since their acquisition dates. (See Note 7—Acquisitions for further details.)

Petroleum Products Terminals. Most of our petroleum products terminals are strategically located along or near third-party pipelines or petroleum refineries. The petroleum products terminals provide a variety of services such as distribution, storage, blending, inventory management and additive injection to a diverse customer group including governmental customers and end-users in the downstream refining, retail, commercial trading, industrial and petrochemical industries. Products stored in and distributed through the petroleum products terminal network include refined petroleum products, blendstocks, crude oils, heavy oils and feedstocks. Our terminal network consists of seven marine terminals and 27 inland terminals. Five of our marine terminal facilities are located along the Gulf Coast and two marine terminal facilities are located on the East Coast. Our inland terminals are located primarily in the southeastern United States.

During the fourth quarter of 2009, we acquired certain assets for $32.2 million. The operating results from this acquisition were included in our petroleum products terminals segment's results since the acquisition date. (See Note 7—Acquisitions for further details.)

Ammonia Pipeline System. Our ammonia pipeline system consists of an 1,100-mile ammonia pipeline and six company-owned terminals. Shipments on the pipeline primarily originate from ammonia production plants located in Texas and Oklahoma for transport to terminals throughout the Midwest. The ammonia transported through our system is used primarily as nitrogen fertilizer.

4. Summary of Significant Accounting Policies

Basis of Presentation. Our consolidated financial statements include the petroleum products pipeline system, the petroleum products terminals and the ammonia pipeline system. All intersegment transactions have been eliminated.

Use of Estimates. The preparation of our consolidated financial statements in conformity with accounting principles generally accepted in the United States 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 the reported amounts of revenue and expense during the reporting periods. Actual results could differ from those estimates.

Regulatory Reporting. Our petroleum products pipelines are subject to regulation by the Federal Energy Regulatory Commission ("FERC"), which prescribes certain accounting principles and practices for the annual Form 6 report filed with the FERC that differ from those used in these financial statements. Such differences relate primarily to capitalization of interest, accounting for gains and losses on disposal of property, plant and equipment and other adjustments. We follow U.S. generally accepted accounting principles ("GAAP") where such differences of accounting principles exist.

Cash Equivalents. Cash and cash equivalents include demand and time deposits and other highly marketable securities with original maturities of three months or less when acquired. We periodically assess the financial condition of the institutions where these funds are held and believe that our credit risk is minimal.

Accounts Receivable and Allowance for Doubtful Accounts. Accounts receivable represent valid claims against non-affiliated customers and are recognized when products are sold or services are rendered, except tariff-related transportation services of our petroleum products pipeline system, which are recognized when our customer's product enters our system. We extend credit terms to certain customers based on historical dealings and to other customers after a review of various credit indicators. An allowance for doubtful accounts is established for all or any portion of an account where collections are considered to be at risk and reserves are evaluated 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. Accounts receivable are written off when the account is deemed uncollectible.

Inventory Valuation. Inventory is comprised primarily of refined petroleum products, natural gas liquids, transmix and additives, which are stated at the lower of average cost or market.

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

Most of our assets are depreciated individually on a straight-line basis over their useful lives; however, the individual components of certain assets, such as some of our older tanks, are grouped together into a composite asset and those assets are depreciated using a composite rate. We assign asset lives based on reasonable estimates when an asset is placed into service. Subsequent events could cause us to change our estimates, which would impact the future calculation of depreciation expense. The depreciation rates for most of our pipeline assets are approved and regulated by the FERC. Assets with the same useful lives and similar characteristics are depreciated using the same rate. The range of depreciable lives by asset category is detailed in Note 10—Property, Plant and Equipment.

The carrying value of property, plant and equipment sold or retired and the related accumulated depreciation is removed from our accounts and any associated gains or losses are recorded on our income statement in the period of sale or disposition.

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

Asset Retirement Obligation. We record asset retirement obligations under the provisions of ASC 410-20, *Asset Retirement and Environmental Obligations—Asset Retirement Obligations.* ASC 410-20 requires the fair value of a liability related to the retirement of long-lived assets be recorded at the time a legal obligation is incurred, if the liability can be reasonably estimated. When the liability is initially recorded, the carrying amount of the related asset is increased by the amount of the liability. Over time, the liability is accreted to its future value, with the accretion recorded to expense. ASC 410-20 further clarifies that where there is an obligation to perform an asset retirement activity, even though uncertainties exist about the timing or method of settlement, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be determined.

Our operating assets generally consist of underground refined products and ammonia pipelines and related facilities 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 removal of the pipelines and related facilities from 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 $1.9 million liability associated with anticipated tank liner replacements, we have recorded no liability or corresponding asset in conjunction with ASC 410-20 as both the amounts and timing of such potential future costs are indeterminable.

Equity Investments. We account for investments greater than 20% in affiliates which we do not control by the equity method of accounting. Under this method, an investment is recorded at our acquisition cost, plus equity in undistributed earnings or losses since acquisition, less distributions received and less 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. 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. No equity investment impairments were recognized during 2007, 2008 or 2009.

Goodwill and Other Intangible Assets. We account for goodwill under the provisions of ASC 350-20-35, *Goodwill and Other—Goodwill—Subsequent Measurement*. In accordance with the provisions of this ASC, goodwill, which represents the excess of cost over fair value of assets of businesses acquired, is not amortized but is evaluated 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 $14.8 million at both December 31, 2008 and 2009. Our reported goodwill at December 31, 2009 included $2.9 million acquired in transactions involving our petroleum products terminals segment and $11.9 million acquired in transactions involving our petroleum products pipeline system segment.

The determination of whether goodwill is impaired is based 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) revenue growth of 1.5% per year and expense growth of 1.5% per year, except G&A costs with an assumed growth of 3.5% per year, (iii) weighted-average cost of capital of 11.1% based on assumed cost of debt of 6.2%, assumed cost of equity of 14.3% and a 40%/60% debt-to-equity ratio, (iv) annual maintenance capital spending growth of 2.5% and (v) 8 times earnings before interest, taxes and depreciation and amortization multiple for terminal value. We selected October 1 as our impairment measurement test date and have determined that our goodwill was not impaired as of October 1, 2007, 2008 or 2009. If impairment were to occur, the amount of the impairment would be charged 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. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in our financial statements.

Other intangible assets are amortized over their estimated useful lives of 5 years up to 25 years. The weighted-average asset life of our other intangible assets at December 31, 2009 was approximately 7 years. The useful lives are adjusted if events or circumstances indicate there has been a change in the remaining useful lives. Our other intangible assets are reviewed for impairment whenever events or changes in circumstances indicate that the recoverability of the carrying amount of the intangible asset should be assessed. We recognized no impairments for other intangible assets in 2007, 2008 and 2009. Amortization of other intangible assets was $1.5 million each year in 2007 and 2008 and $1.7 million in 2009.

Impairment of Long-Lived Assets. We have adopted the provisions of ASC 360-35; paragraphs 15 through 49, *Property, Plant and Equipment—Subsequent Measurement—Impairment or Disposal of Long-Lived Assets*. In accordance with these provisions, 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. The determination of whether impairment has occurred is based on management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. The amount of the impairment recognized is calculated 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.

Long-lived assets to be disposed of through sales that meet specific criteria are classified as "held for sale" and are recorded 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 2007, 2008 or 2009.

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 recorded during 2007 and 2008 were insignificant and there were no impairments recorded in 2009. The inputs for the valuation models used in determining the fair value of assets impaired during 2007 and 2008 were Level 3—Significant Unobservable Inputs as described in ASC 820, *Fair Value Measurements*.

Lease Financings. Direct financing leases were accounted for such that the minimum lease payments plus the unguaranteed residual value accruing to the benefit of the lessor was recorded as the gross investment in the lease. The net investment in the lease was the difference between the total minimum lease payment receivable and the associated unearned income. We had no direct financing leases at December 31, 2009.

Debt Placement Costs. Costs incurred for debt borrowings are capitalized as paid and amortized over the life of the associated debt instrument using the effective interest method. When debt is retired before its scheduled maturity date, any remaining placement costs associated with that debt are written off. When we modify our revolving credit facility where the borrowing capacity remains the same or is increased, the unamortized deferred costs associated with the old revolving credit facility, any fees paid to the creditor and any third-party cost incurred are capitalized and amortized over the term of the new revolving credit facility.

Interest Capitalized. Interest on borrowed funds is capitalized on projects during construction based on the weighted-average interest rate of our debt. We capitalize interest on all construction projects requiring a completion period of three months or longer and total project costs exceeding $0.5 million.

Pension and Postretirement Medical and Life Benefit Obligations. We sponsor three pension plans, which cover substantially all of our employees, a postretirement medical and life benefit plan for selected 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.

Pension, postretirement medical and life benefits costs are developed from actuarial valuations. Actuarial assumptions are established to anticipate future events and are used in calculating the expense and liabilities related to these plans. These factors include assumptions management makes with regards to 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, subjective factors such as withdrawal and mortality rates are used 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 impact the amount of pension and postretirement medical and life benefit expense we have recorded or may record.

Paid-Time Off Benefits. Liabilities for paid-time off benefits are recognized when earned. Paid-time off liabilities were $9.8 million and $10.2 million at December 31, 2008 and 2009, respectively. These balances represented the remaining vested paid-time off benefits of employees. Liabilities for paid-time off are reflected in the payroll and benefits balances of the accompanying consolidated balance sheets.

Derivative Financial Instruments. We account for derivative instruments in accordance with ASC 815, *Derivatives and Hedging*, which establishes accounting and reporting standards requiring that derivative instruments be recorded on the balance sheet at fair value as either assets or liabilities.

For those instruments that qualify for hedge accounting, the accounting treatment depends on each instrument's intended use and how it is designated. Derivative financial instruments qualifying for hedge accounting treatment can generally be divided into two categories: (1) cash flow hedges and (2) fair value hedges. Cash flow hedges are executed to hedge the variability in cash flows related to a forecasted transaction. Fair value hedges are executed to hedge 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, hedge accounting is discontinued prospectively with the change in the fair value of the derivative recorded in current earnings. The change in fair value of derivative financial instruments that either do not qualify for hedge accounting or are not designated 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. We use, or have used, derivative agreements primarily for fair value hedges of our debt, cash flow hedges of forecasted debt transactions and for forward purchases and forward sales of petroleum products. Such financial instruments involve the risk of non-performance by the counterparty, which could result in material losses to us.

We also use derivatives to help us manage purchases and sales of petroleum products. Derivatives that qualify for and are designated as normal purchases and sales are accounted for using traditional accrual accounting. As of December 31, 2009, we had commitments under forward purchase contracts for petroleum product purchases of approximately 0.2 million barrels that will be accounted for as normal purchases totaling approximately $22.4 million, and we had commitments under forward sales contracts for product sales of approximately 0.5 million barrels that will be accounted for as normal sales totaling approximately $45.6 million.

We have also entered into New York Mercantile Exchange ("NYMEX") commodity based futures contracts to hedge against price changes on a portion of the petroleum products we expect to sell in the future. None of these agreements qualify for normal sales treatment under ASC 815. Some of these contracts qualify as cash flow hedges under ASC 815 while others do not. We record the effective portion of the gain or losses for the contracts which qualify as hedge cash flows in other comprehensive income and the ineffective portion in product sales revenues. Each period, we record the change in fair value of those agreements which are not designated as hedges in product sales revenues. We reclassify gains and losses from contracts that qualify as hedges from other comprehensive income to product sales revenues when the hedged transaction occurs and the derivative agreement is cancelled.

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

See *Comprehensive Income* in this Note 4 for details of the derivative gains and losses included in accumulated other comprehensive loss.

Revenue Recognition. Petroleum pipeline and ammonia transportation revenues are recognized when shipments are complete. For ammonia shipments and shipments of petroleum 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. Injection service fees associated with customer proprietary additives are recognized upon injection to the customer's product, which occurs at the time the product is delivered. Leased tank storage, pipeline capacity leases, terminalling, throughput, ethanol loading and unloading services, laboratory testing, data services, pipeline operating fees and other miscellaneous service-related revenues are recognized upon completion of contract services. Product sales are recognized upon delivery of the product to the customer. Product sales are increased for gains and decreased for losses associated with the period change in fair value of our NYMEX agreements which are not designated as hedges and for the ineffective portion of our NYMEX agreements that are designated as hedges. When the physical sale of hedged petroleum products occurs, product sales are increased for gains and decreased for losses of the effective portion of the associated derivative agreement.

Deferred Transportation Revenues and Costs. Customers on our petroleum products pipeline are invoiced 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. These deferred costs are determined using judgments and assumptions that management considers reasonable.

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

Variable-Rate Agreements. Our operations historically included terminalling agreements with customers under which we provided storage rental and throughput fees based on discounted rates. In addition to the discounted storage rentals and throughput fees, our revenues also included a variable-rate storage fee equal to approximately half of cumulative profits, in excess of an established threshold, our customer derived from trading petroleum products through our storage tank over the contract period. For all of these agreements, we were under no obligation to share in any trading losses sustained by our customer. Under these agreements, we recognized the discounted storage rental and throughput fees each accounting period as the services were performed. However, the cumulative amounts of trading profits or losses over the contract period that were realized by our customer (and therefore, the revenue we earned related to these shared trading profits) were not determinable until the end of the contract term. Because trading losses sustained by our customer on the last day of the contract period could offset all trading profits realized up to that point, the cumulative trading profit over the contract period would be zero. In such a situation we would have recognized no revenues under the variable-rate portion of the agreement.

Based on the circumstances of these agreements and in accordance with ASC 605-20-S25, *Revenue Recognition-Services-Recognition-Accounting for Management Fees Based on a Formula*, our policy was to defer recognition of the variable-rate portion of revenue from these agreements until the end of the contract term. We recognized $2.8 million and $0.9 million of revenue when a contract term expired on December 31, 2007 and 2008, respectively. During 2009, we recognized $2.3 million of revenue when a variable-rate terminalling agreement was cancelled. We had no variable-rate terminalling agreements in effect at December 31, 2009.

In March 2008, in conjunction with the assignment of a supply agreement, Partners entered into an additional agreement with the assignee under which it agreed that if the pricing under the supply agreement, less associated operational costs, did not exceed its full tariff charge, then it would share in 50% of any shortfall versus its full tariff, and similarly, it would be entitled to 50% of any excess above a certain threshold that included its tariff charge. The agreement is structured such that our share of the 50% shortfall cannot exceed the tariff we receive from transporting the associated barrels. All adjustments resulting from this agreement have been reflected in transportation and terminals revenues. Our 50% share of the profit (loss) from this agreement was $1.8 million for the period from inception of the agreement through December 31, 2008 and $(1.0) million for the twelve months ended December 31, 2009.

G&A Expenses. Under a services agreement, we historically paid an affiliate for the direct and indirect G&A expenses our affiliate incurred on our behalf. Under an omnibus agreement, another affiliate reimbursed us for the expenses in excess of a G&A cap.

Equity-Based Incentive Compensation Awards. The compensation committee of our general partner has approved incentive awards of phantom units, without distribution equivalent rights, representing limited partner interests in us to certain employees. In addition, our general partner has issued phantom units with distribution equivalent rights to our independent directors. These awards are accounted for as prescribed in ASC 718, *Compensation—Stock Compensation*.

Under ASC 718, we classify unit award grants as either equity or liabilities. Fair value for award grants classified as equity is determined on the grant date of the award and this value is recognized as compensation expense ratably over the requisite service period, which is the vesting period of each unit award. Fair value for equity awards is calculated as the closing price of our limited partner units on the grant date reduced by the present value of expected per-unit distributions to be paid during the requisite service period. Unit award grants classified as liabilities are re-measured at fair value on the close of business at each reporting period end until settlement date. Each period's compensation expense for liability awards is the re-measured value of the award grants times the percentage of the requisite service period completed less previously-recognized compensation expense. Compensation expense related to equity-based awards is included in operating and G&A expenses on our consolidated statements of income.

Certain unit award grants include performance and other provisions, which can result in payouts to the recipients from zero up to 200% of the amount of the award. Additionally, certain unit award grants are also subject to personal and other performance components which could increase or decrease the number of limited partner units to be paid out by 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.

Environmental. Environmental expenditures that relate to current or future revenues are expensed or capitalized based on the nature of the expenditures. Expenditures that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities are recorded when environmental costs are probable and can be reasonably estimated. Environmental liabilities assumed in a business combination are recorded at fair value. Otherwise, environmental liabilities are recorded 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. At December 31, 2009, expected payments on our discounted environmental liabilities were \$0.4 million in 2010, \$0.3 million in 2011 and \$0.2 million each year in 2012, 2013 and 2014 and \$8.8 million for all periods thereafter. A reconciliation of our undiscounted environmental liabilities to amounts reported on our consolidated balance sheets is provided in the table below (in thousands). See Note 19—Commitments and Contingencies for a discussion of the changes in our environmental liabilities between December 31, 2008 and December 31, 2009.

	December 31,	
	2008	2009
Aggregated undiscounted environmental liabilities	\$47,549	\$40,102
Amount of discount on environmental liabilities	(5,749)	(5,665)
Environmental liabilities, as reported	\$41,800	\$34,437

Environmental liabilities are recorded 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. We maintain selective insurance coverage, which may cover all or portions of certain environmental expenditures. Receivables are recognized in cases where the realization of reimbursements of remediation costs is considered probable. We would sustain losses to the extent of amounts we have recognized as environmental receivables if the counterparties to those transactions become insolvent or are otherwise unable to perform their obligations to us.

Prior to the simplification, costs related to remediation liabilities covered by indemnifications from a former owner of our general partner were allocated to our general partner. Following the simplification, these costs are allocated to the limited partners.

The determination of the accrual amounts recorded for environmental liabilities include 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.

Non-Controlling Owners' Interests of Consolidated Subsidiaries ("Non-Controlling Owners' Interest"). The non-controlling owners' interest on our balance sheet reflected the portion of Partners owned by its partners other than Holdings. At December 31, 2008, the non-controlling owners' interest was approximately 98%. Subsequent to the simplification, we no longer have non-controlling owners' interest.

Income Taxes. We are a partnership for income tax purposes and therefore have not been subject to federal income taxes 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 as a result 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 the net revenues of our assets apportioned to the state of Texas.

Allocation of Net Income. For periods prior to the simplification, net income allocated to non-controlling owner's interest was determined by deducting Partners GP's allocated share of Partners' net income for the period from Partners' net income. Partners GP's allocated share of Partners' net income was determined by multiplying Partners' net income by Partners GP's proportionate share of distributions (including incentive distribution rights) for the period, adjusted for direct charges by Partners to Partners GP, plus Partners GP's approximate 2% ownership interest in undistributed Partners' net income, if any.

During 2007 and until December 2008, the net income remaining after the net income allocation to the non-controlling owners' interest was allocated to Holdings GP and Holdings limited partners based on their respective ownership interests, with adjustments made for any charges specifically allocated to Holdings GP. Holdings acquired Holdings GP in December 2008; therefore, all of its net income subsequent to that date was allocable to its limited partners. Following the simplification, we allocate all of our net income to our limited partners.

Net Income Per Unit. Basic net income per unit for each period is calculated by dividing the limited partners' allocation of net income by the weighted-average number of limited partner units outstanding. Diluted net income per unit for each period is the same calculation as basic net income per unit, except the weighted-average limited partner units outstanding include the dilutive effect of phantom unit grants associated with our long-term incentive plan. The net income per unit amounts included in these financial statements have been retrospectively restated for the reverse unit split that occurred in association with the simplification.

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. We have recorded total comprehensive income with our consolidated statement of owners' equity as allowed under ASC 220.

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

	Derivative Gains (Losses)	Pension and Postretirement Liabilities	Accumulated Other Comprehensive Loss*
Balance, January 1, 2007	$ (782)	$ (9,305)	$(10,087)
Net gain on cash flow hedges	5,018	—	5,018
Reclassification of net gain on interest rate cash flow hedges to interest expense	(419)	—	(419)
Pension settlement expense and amortization of prior service cost and net actuarial loss	—	1,833	1,833
Adjustment to recognize the funded status of postretirement benefit plans	—	(939)	(939)
Balance, December 31, 2007	3,817	(8,411)	(4,594)
Reclassification of net gain on interest rate cash flow hedges to interest expense	(164)	—	(164)
Amortization of prior service cost and net actuarial loss	—	(88)	(88)
Adjustment to recognize the funded status of postretirement benefit plans	—	(12,272)	(12,272)
Balance, December 31, 2008	3,653	(20,771)	(17,118)
Net loss on cash flow hedges	(6,804)	—	(6,804)
Reclassification of net gain on interest rate cash flow hedges to interest expense	(164)		(164)
Reclassification of net loss on commodity hedges to product sales revenue	5,058	—	5,058
Amortization of prior service cost and net actuarial loss	—	1,256	1,256
Adjustment to recognize the funded status of postretirement benefit plans	—	9,771	9,771
Balance, December 31, 2009	$ 1,743	$ (9,744)	$ (8,001)

* Includes amounts allocated to the non-controlling owners' interest for periods prior to the simplification.

New Accounting Pronouncements

In August 2009, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2009-05, an update to ASC 820-10-35, *Fair Value Measurements*. ASU 2009-05 provides guidance on measuring the fair value of liabilities. The guidance in ASU 2009-05 was effective for the first reporting period, including interim periods, beginning after August 28, 2009. Our adoption of this ASU on September 1, 2009 did not have a material impact on our financial position, results of operations or cash flows.

In June 2009, the FASB issued Statement of Financial Accounting Standards ("SFAS") No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles*. The new codification superseded all existing GAAP standards and became the single source of GAAP authoritative literature, effective for financial statements issued for interim and annual periods ending after September 15, 2009.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events (as amended)*. This Statement required the disclosure of subsequent events to be distinguished between recognized and non-recognized subsequent events. Further, entities were required to include a description of the period through which subsequent events were evaluated. Our adoption of this Statement on June 30, 2009 did not have a material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB issued FASB Staff Position ("FSP") No. FAS 107-1 and Accounting Principles Board ("APB") 28-1, *Interim Disclosures About Fair Value of Financial Instruments*. This FSP amended SFAS No. 107 (FASB ASC 825-10) and APB Opinion No. 28: (FASB ASC 270-10) by requiring quarterly as well as annual disclosures of the fair value of all financial instruments. The disclosures were to be in a form that made it clear whether the fair value and carrying amounts represent assets or liabilities and how the carrying amounts relate to what was reported on the balance sheet. Our adoption of this Standard on June 30, 2009 did not have a material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB issued FSP No. FAS 141(R)-1, *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination that Arise from Contingencies*. This FSP amended and clarified FASB Statement No. 141 (revised 2007), *Business Combinations*, to address application issues on the initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This FSP was effective for assets or liabilities arising from contingencies in business combinations that occurred following the start of the first fiscal year that began on or after December 15, 2008. Our adoption of this FSP did not have a material impact on our financial position, results of operations or cash flows.

In December 2008, the FASB issued FSP FAS 132(R)-1, *Employers' Disclosures about Postretirement Benefit Plan Assets*. This FSP expanded the disclosure requirements for employer pension plans and other postretirement benefit plans to include factors that are pertinent to an understanding of investment policies and strategies. The additional disclosure requirements included; (i) for annual financial statements, the fair value of each major category of plan assets separately for pension and other postretirement plans, (ii) a narrative description of the basis used to determine the expected long-term rate of return on asset assumption, (iii) information to enable users of financial statements to assess the inputs and valuation techniques used to develop fair value measurements of plan assets at the annual reporting date and (iv) for fair value measurements using unobservable inputs, disclosure of the effect of the measurements on changes in plan assets for the period. This FSP was effective for fiscal years ending after December 15, 2009, with early application permitted. Provisions of this FSP were not required for earlier periods presented for comparative purposes. Our adoption of this FSP did not have a material impact on our financial position, results of operations or cash flows.

In September 2008, the FASB issued Emerging Issues Task Force ("EITF") No. 08-6, *Equity Method Investment Accounting Considerations*. This EITF required entities to measure their equity method investments initially at cost in accordance with SFAS No. 141(R), *Business Combinations*. Further, the EITF clarified that entities should not separately test an investee's underlying indefinite-lived intangible asset for impairment; however, they are required to recognize other-than-temporary impairments of an equity method investment in accordance with APB No. 18, *The Equity Method of Accounting for Investments in Common Stock*. In addition, entities are required to account for a share issuance by an equity method investee as if the investor had sold a proportionate share of its investment. Any gain or loss to the investor resulting from an investee's share issuance is to be recognized in earnings. This EITF was effective for fiscal years beginning on or after December 15, 2008, and interim periods within those fiscal years, and was to be applied prospectively. Our adoption of this EITF in January 2009 did not have a material impact on our financial position, results of operations or cash flows.

In June 2008, the FASB issued FASB FSP No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities*. This FSP clarified that unvested share-based payment awards that contain nonforfeitable rights to distributions or distribution equivalents, whether paid or unpaid, are participating securities as defined in SFAS No. 128, *Earnings Per Share,* and are to be included in the computation of earnings per unit pursuant to the two-class method. This FSP was effective for financial statements issued after December 15, 2008 and interim periods within those years with prior period earnings per unit data retrospectively adjusted. Our adoption of this EITF in January 2009 did not have a material impact on our financial position, results of operations, cash flows or earnings per unit.

In April 2008, the FASB issued FSP No. FAS 142-3, *Determination of the Useful Life of Intangible Assets*. This FSP amended the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, *Goodwill and Other Intangible Assets.* This FSP also expanded the disclosures required for recognized intangible assets. This FSP was effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. Our adoption of this FSP in January 2009 did not have a material impact on our financial position, results of operations or cash flows.

In March 2008, the FASB ratified EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships.* Under EITF No. 07-4, the excess of distributions over earnings and/or excess of earnings over distributions for each period are required to be allocated to the entities' general partner based solely on the general partner's ownership interest at the time. This EITF was effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. Our adoption of this EITF in January 2009 did not have a material impact on our income allocation methodology or our calculation of earnings per unit.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities.* SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* established, among other things, the disclosure requirements for derivative instruments and for hedging activities. SFAS No. 161 amended SFAS No. 133, requiring qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. SFAS No. 161 was effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Our adoption of this Standard in January 2009 did not have a material effect on our financial position, results of operations or cash flows.

In February 2008, the FASB issued FSP No. 157-1, *Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13*. FSP No. 157-1 amends SFAS No. 157, *Fair Value Measurements*, to exclude SFAS No. 13, *Accounting for Leases*, and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS No. 13. However, this scope exception did not apply to assets acquired and liabilities assumed in a business combination that are required to be measured at fair value under SFAS No. 141(R), *Business Combinations*, or SFAS No. 141 (revised 2007), *Business Combinations*, regardless of whether those assets and liabilities are related to leases. This FSP was effective with the initial adoption of SFAS No. 157, which we adopted on January 1, 2007. Our adoption of this FSP did not have a material effect on our financial position, results of operations or cash flows.

5. Consolidated Statements of Cash Flows

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

	Year Ended December 31,		
	2007	2008	2009
Accounts receivable and other accounts receivable	$ 25,404	$ 24,270	$(31,872)
Inventory	(28,912)	72,728	(59,135)
Energy commodity derivative contracts, net of derivative deposits	—	(1,206)	(8,181)
Supply agreement deposit	5,000	(18,500)	—
Reimbursable costs	(1,201)	(4,964)	(5,104)
Accounts payable	(11,472)	(253)	(3,909)
Accrued payroll and benefits	4,776	(1,739)	8,416
Accrued interest payable	(2,069)	7,880	17,800
Accrued taxes other than income	3,579	(894)	1,110
Accrued product purchases	(19,868)	(19,356)	12,923
Current and noncurrent environmental liabilities	406	(18,368)	(7,383)
Other current and noncurrent assets and liabilities	(15,958)	(7,431)	3,562
Total	$(40,315)	$ 32,167	$(71,773)

At December 31, 2007, 2008 and 2009, the long-term pension and benefits liability was increased (decreased) by $0.9 million, $12.3 million and $(9.8) million, respectively, resulting in an increase (decrease) in accumulated other comprehensive loss. These non-cash amounts were reflected in the consolidated financial statements but were not reflected in the statements of cash flows.

6. Allocation of Net Income

The allocation of net income for purposes of both calculating earnings per unit and determining the capital balances of the general partner, limited partners and the non-controlling owners' interest was as follows (in thousands):

	Year Ended December 31,		
	2007	2008	2009
Net income	$230,754	$330,103	$226,475
Net income applicable to non-controlling owners' interest (Partners' net income allocated to its owners other than Holdings)[c]	175,356	244,430	99,729
Net income applicable to limited partners and Holdings GP	55,398	85,673	126,746
Allocation of net income applicable to limited partners and Holdings GP:			
Direct charges to Holdings GP:			
Reimbursable G&A costs[a]	6,191	2,072	—
Income applicable to limited partners and Holdings GP before direct charges to Holdings GP	61,589	87,745	126,746
Holdings GP's share of income[b]	0.0141%	0.0130%	—
Holdings GP's allocated share of net income before direct charges	9	12	—
Direct charges to Holdings GP	6,191	2,072	—
Net loss allocated to Holdings GP	$ (6,182)	$ (2,060)	$ —
Net income applicable to limited partners and Holdings GP	$ 55,398	$ 85,673	$126,746
Less: net loss allocated to Holdings GP	(6,182)	(2,060)	—
Net income allocated to limited partners	$ 61,580	$ 87,733	$126,746

(a) Reimbursable G&A costs for 2007 and 2008 included $2.1 million and $0.4 million, respectively, of non-cash expenses related to payments by an affiliate to one of our executive officers. Because the limited partners did not share in these costs, they were allocated to Holdings GP.

(b) In December 2008, Holdings acquired Holdings GP. Subsequent to that transaction, Holdings GP was no longer allocated a portion of consolidated net income.

(c) These amounts represent Partners' allocation of pre-simplification net income to the non-controlling owners' interest. The simplification was completed during the third quarter of 2009. Because Holdings was dissolved and Partners' incentive distribution rights were eliminated, the calculation of the allocation of net income to the non-controlling owners' interest was changed for the third quarter of 2009. The allocation of net income to the non-controlling owners' interest for 2007, 2008 and for the period from January 1, 2009 through September 27, 2009 was determined as follows:

	2007	2008	Six Months Ended June 30, 2009
			(in thousands)
Partners net income	$242,790	$346,613	$98,375
Direct charges (credits) to Partners GP	10,617	(4,344)	1,066
Income before direct charges (credits) to Partners GP	253,407	342,269	99,441
Partners GP's share of Partners net income	28.64%	26.46%	33.06%
Partners GP's share of Partners net income before direct charges (credits)	72,568	90,560	32,876
Direct (charges) credits to Partners GP	(10,617)	4,344	(1,066)
Partners net income allocated to Partners GP	$ 61,951	$ 94,904	$31,810
Partners net income	$242,790	$346,613	$98,375
Partners net income allocated to Partners GP	61,951	94,904	31,810
Partners net income allocated to its limited partners	180,839	251,709	66,565
Partners' limited partners' allocated share of step-up adjustments	(5,483)	(7,279)	(2,890)
Partners' net income allocated to non-controlling owners' interest	$175,356	$244,430	$63,675

**Partners' Net Income Allocated to
Non-Controlling Owners' Interest for the Period from January 1, 2009 through
September 27, 2009
(in thousands)**

Partners' net income allocated to the non-controlling owners' interest for the period from January 1, 2009 through June 30, 2009	$63,675
Partners' net income allocated to non-controlling owners' interest for the period from July 1, 2009 through September 27, 2009(1)	36,054
Partners' net income allocated to non-controlling owners' interest for the period from January 1, 2009 through September 27, 2009	$99,729

(1) The net income allocated to the non-controlling owners' interest for this period was Partners' pre-simplification net income for third quarter 2009 ($57,388) times the percentage of third quarter 2009 distributions paid on Partners' pre-simplification outstanding limited partner units (62.8%) to the total distributions paid for the quarter (which included the distributions paid on the Holdings units that converted to MMP units on September 28, 2009).

7. Acquisitions

Longhorn Partners Pipeline, L.P.

In July 2009, Partners acquired substantially all of the assets of Longhorn Partners Pipeline, L.P. (which is referred to herein as the "Longhorn acquisition") for $252.3 million plus the fair market value of the linefill of $86.1 million. The operating results from this acquisition have been included in the petroleum products pipeline system segment's results since the acquisition date.

The Longhorn acquisition primarily included an approximate 700-mile common carrier pipeline system that transports refined petroleum products from Houston to El Paso, Texas and a terminal in El Paso, Texas. The

El Paso, Texas terminal serves local petroleum products demand and distributes product to connecting third-party pipelines for ultimate delivery to markets in Arizona and New Mexico. We are in the process of connecting this pipeline system to our existing East Houston, Texas terminal to provide additional supply options for current and potential customers to transport petroleum products to southwestern markets.

The Longhorn acquisition was accounted for as an acquisition of a business under the purchase method of accounting in accordance with ASC 805, *Business Combinations*. The assets acquired and liabilities assumed were recorded at their estimated fair market values as of the acquisition date. The purchase price and assessment of the fair value of the assets acquired and liabilities assumed was as follows (in thousands):

Purchase price	$338,439
Fair value of assets acquired (liabilities assumed):	
Property, plant and equipment	$252,327
Inventory	86,132
Environmental liabilities assumed	(20)
Total	$338,439

Revenues and net operating loss resulting from the July 29, 2009 date of the Longhorn acquisition through December 31, 2009 were $67.3 million and $(17.1) million, respectively. These amounts have been included in the current period operating results of our petroleum products pipeline system segment.

Oklahoma Terminal

In September 2009, we acquired a terminal in Oklahoma for $20.0 million in a sale/lease-back arrangement. The assets acquired were recorded at their estimated fair market values as of the acquisition date in our petroleum products pipeline segment. The purchase price and assessment of the fair value of the assets acquired was as follows (in thousands):

Purchase price	$20,003
Fair value of assets acquired:	
Property, plant and equipment	$20,003

Louisiana Terminal Acquisition

In October 2009, we acquired a facility for $32.2 million to expand one of our existing marine terminals in Louisiana. The assets acquired were recorded at their estimated fair market values as of the acquisition date in our petroleum products terminals segment. The purchase price and assessment of the fair value of the assets acquired and liabilities assumed was as follows (in thousands):

Purchase price	$32,164
Fair value of assets acquired:	
Property, plant and equipment	$32,279
Other intangibles	2,041
Contract liability	(1,820)
Other	(336)
Total	$32,164

Pro Forma Information (unaudited)

The following summarized pro forma consolidated income statement information assumes that the acquisitions discussed above occurred as of January 1, 2008. These pro forma results are for comparative purposes only and may not be indicative of the results that would have occurred if these acquisitions had been completed as of the periods shown below or the results that will be attained in the future. The amounts presented below are in thousands:

	Year Ending December 31, 2008		
	As Reported	Pro Forma Adjustments	Pro Forma
Revenues	$1,213,638	$114,392	$1,328,030
Net income	$ 330,103	$ 21,117	$ 351,220

	Year Ending December 31, 2009		
	As Reported	Pro Forma Adjustments	Pro Forma
Revenues	$1,014,171	$ 13,921	$1,028,092
Net income	$ 226,475	$ (20,617)	$ 205,858

Significant pro forma adjustments for the Longhorn acquisition include its revenues and operating margin for the period prior to the date it was acquired by Partners. Because the assets included in the Longhorn acquisition had minimal commercial activity following the former owner's bankruptcy filing in December 2008, revenues and net income generated by the assets were substantially lower in 2009.

Pro forma adjustments for the Oklahoma terminal include lease revenue based on a $2.0 million annual lease payment amount and depreciation expense based on $0.5 million annually.

Pro forma adjustments for our other terminal acquisition include its revenues and net income for the period prior to the date we acquired it, based on a rolling twelve-month average of its actual results.

Pro forma adjustments include interest expense on borrowings necessary to complete the acquisitions.

8. Inventory

Inventory at December 31, 2008 and 2009 was as follows (in thousands):

	2008	2009
Refined petroleum products	$20,917	$152,776
Natural gas liquids	7,534	17,263
Transmix	13,099	17,230
Additives	6,184	5,732
Total inventory	$47,734	$193,001

The increase in refined petroleum products from 2008 to 2009 is primarily attributable to the linefill and working inventory related to the Longhorn acquisition, which totaled $118.5 million as of December 31, 2009.

During 2008, Partners recorded a $19.7 million lower-of-average-cost-or-market adjustment to its transmix inventory associated with its pipeline product overages and shortages. This adjustment was included in operating expenses on the consolidated statement of income included with these financial statements. In addition, during 2008, Partners recorded lower-of-average-cost-or-market adjustments of $6.4 million and $3.0 million to its refined petroleum products inventory and transmix inventory, respectively, associated with its petroleum products blending and fractionation activities. These adjustments were recorded as a component of product purchases on the consolidated statement of income included with these financial statements.

9. Product Sales Revenues

The amounts reported as product sales revenues on our consolidated statements of income include revenues from the sale of petroleum products and from mark-to-market adjustments from NYMEX contracts. We began using NYMEX contracts during the third quarter of 2008 as economic hedges against changes in the price of petroleum products we expected to sell from our petroleum products blending activities. From the third quarter of 2008 through the second quarter of 2009, none of the NYMEX contracts we entered into qualified for hedge accounting treatment under ASC 815-30, *Derivatives and Hedging*. However, beginning in July 2009, because of other agreements that we entered into, some of the NYMEX contracts associated with our petroleum products blending activities qualified for hedge accounting treatment and were recorded as cash flow hedges. We also use NYMEX contracts as economic hedges against changes in the value of petroleum products associated with linefill and working inventory associated with the Longhorn acquisition. None of these NYMEX contracts have qualified for hedge accounting treatment. As a result of the different accounting treatment applied to the various types of NYMEX contracts we employ, the amounts reported as product sales revenues can include amounts from the following sources:

- The physical sale of petroleum products;
- Mark-to-market adjustments of NYMEX contracts that did not qualify for hedge accounting treatment associated with economic hedges of our petroleum products blending, fractionation activities and linefill and working inventory related to the Longhorn acquisition; and
- The effective portion of the gains or losses of NYMEX contracts that matured during the period which qualified for hedge accounting treatment and were accounted for as cash flow hedges.

In 2007, all of the reported product sales revenues were from the physical sale of petroleum products. For the years ended 2008 and 2009, product sales revenues included the following (in thousands):

	Year Ended December 31,	
	2008	2009
Physical sale of petroleum products	$523,158	$373,055
NYMEX contract adjustments:		
Change in value of NYMEX contracts that did not qualify for hedge accounting treatment associated with our petroleum products blending and fractionation activities	50,937	(23,674)
The effective portion of gains and losses of matured NYMEX contracts that qualified for hedge accounting treatment associated with our petroleum products blending activities	—	(5,058)
Change in value of NYMEX contracts that did not qualify for hedge accounting treatment associated with the linefill related to the Longhorn acquisition	—	(9,858)
Total NYMEX contract adjustments	50,937	(38,590)
Total product sales revenues	$574,095	$334,465

10. Property, Plant and Equipment

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

	December 31, 2008	December 31, 2009	Estimated Depreciable Lives
Construction work-in-progress	$ 120,521	$ 101,265	
Land and rights-of-way	58,901	68,603	
Carrier property	1,467,289	1,743,606	6 – 59 years
Buildings	20,129	26,877	20 – 53 years
Storage tanks	515,706	620,719	20 – 40 years
Pipeline and station equipment	230,517	260,344	3 – 59 years
Processing equipment	405,431	496,087	3 – 56 years
Other	72,178	81,105	3 – 48 years
Total	$2,890,672	$3,398,606	

Carrier property is defined as pipeline assets regulated by the FERC. Other includes interest capitalized at December 31, 2008 and 2009 of $25.4 million and $24.5 million, respectively. Depreciation expense for the years ended December 31, 2007, 2008 and 2009 was $77.6 million, $85.0 million and $95.6 million, respectively.

11. 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 revenue for 2007, 2008 or 2009. The majority of the revenues from Customers A, B and C resulted from sales to those customers of refined petroleum products that were generated in connection with our petroleum products blending and fractionation activities. Customer D purchased petroleum products from us pursuant to a third-party supply agreement that was assigned in March 2008. In general, accounts receivable from these customers are due within 3 days of sale.

	Year Ended December 31, 2007	2008	2009
Customer A	1%	12%	11%
Customer B	2%	12%	5%
Customer C	13%	8%	0%
Customer D	33%	2%	0%
Total	49%	34%	16%

Concentration of Risks. We transport, store and distribute petroleum products for refiners, marketers, traders and end-users of those products. The major concentration of our petroleum products pipeline system's revenues is derived from activities conducted in the central United States. Transportation and storage revenues are generally secured by 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, 2009, we had 1,217 employees. At December 31, 2009, the labor force of 608 employees assigned to our petroleum products pipeline system was concentrated in the central United States.

Approximately 36% of these employees were represented by the United Steel Workers Union ("USW"). Our collective bargaining agreement with the USW expires January 31, 2012. The labor force of 270 employees assigned to our petroleum products terminals operations at December 31, 2009 was primarily concentrated in the southeastern and Gulf Coast regions of the United States. Approximately 11% of these employees were represented by the International Union of Operating Engineers ("IUOE") and covered by a collective bargaining agreement that expires in October 2010. At December 31, 2009, the labor force of 19 employees assigned to our ammonia pipeline system was concentrated in the central United States and none of these employees were covered by a collective bargaining agreement.

12. Employee Benefit Plans

We sponsor two union pension plans for certain employees ("USW plan" and "IUOE plan") and a pension plan for all non-union employees and certain union employees ("Salaried plan"), a postretirement benefit plan for selected employees and a defined contribution plan.

The annual measurement date of the aforementioned 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, 2008 and 2009 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2008	2009	2008	2009
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 42,117	$51,198	$ 17,069	$ 19,157
Service cost	5,473	6,583	435	407
Interest cost	2,698	3,210	1,029	899
Plan participants' contributions	—	—	108	115
Actuarial (gain) loss	2,709	1,550	1,133	(6,738)
Benefits paid	(1,799)	(1,884)	(617)	(488)
Benefit obligation at end of year	51,198	60,657	19,157	13,352
Change in plan assets:				
Fair value of plan assets at beginning of year	36,599	38,213	—	—
Employer contributions	9,143	7,371	509	373
Plan participants' contributions	—	—	108	115
Actual return on plan assets	(5,730)	7,306	—	—
Benefits paid	(1,799)	(1,884)	(617)	(488)
Fair value of plan assets at end of year	38,213	51,006	—	—
Funded status at end of year	$(12,985)	$ (9,651)	$(19,157)	$(13,352)
Accumulated benefit obligation	$ 38,447	$46,380		

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

	Pension Benefits		Other Postretirement Benefits	
	2008	2009	2008	2009
Amounts recognized in consolidated balance sheet:				
Current accrued benefit cost	$ —	$ —	$ (355)	$ (421)
Long-term pension and benefit cost	(12,985)	(9,651)	(18,802)	(12,931)
	(12,985)	(9,651)	(19,157)	(13,352)
Accumulated other comprehensive loss:				
Net actuarial loss (gain)	15,970	11,308	6,209	(699)
Prior service cost (credit)	1,569	1,261	(2,977)	(2,126)
	17,539	12,569	3,232	(2,825)
Net amount recognized in consolidated balance sheet	$ 4,554	$ 2,918	$(15,925)	$(16,177)

Net periodic benefit expense for the years ended December 31, 2007, 2008 and 2009 and other changes in plan assets and benefit obligations recognized in other comprehensive loss during 2008 and 2009 were as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2007	2008	2009	2007	2008	2009
Components of net periodic pension and postretirement benefit expense:						
Service cost	$ 5,765	$ 5,473	$ 6,583	$ 533	$ 435	$ 407
Interest cost	2,539	2,698	3,210	1,026	1,029	899
Expected return on plan assets	(2,497)	(2,702)	(2,723)	—	—	—
Amortization of prior service cost (credit)	308	307	307	(851)	(852)	(851)
Amortization of net actuarial loss	414	150	1,630	688	307	170
Pension settlement expense[a]	1,274	—	—	—	—	—
Net periodic expense	$ 7,803	$ 5,926	$ 9,007	$1,396	$ 919	$ 625

	Pension Benefits		Other Postretirement Benefits	
	2008	2009	2008	2009
Other changes in plan assets and benefit obligations recognized in other comprehensive loss:				
Net actuarial loss (gain)	$11,139	$(3,033)	$1,133	$(6,738)
Amortization of net actuarial loss	(150)	(1,630)	(307)	(170)
Amortization of prior service cost (credit)	(307)	(307)	852	851
Total recognized in other comprehensive loss	10,682	(4,970)	1,678	(6,057)
Total recognized in net periodic benefit cost and other comprehensive loss	$16,608	$ 4,037	$2,597	$(5,432)

(a) 26 participants took a lump sum distribution from the USW plan in 2007, resulting in a pension settlement expense of $1.3 million.

Expenses related to the defined contribution plan were $4.6 million, $5.0 million and $5.3 million in 2007, 2008 and 2009, respectively.

The estimated net actuarial loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2010 are $0.6 million and $0.3 million, respectively. The prior service credit for the other defined benefit postretirement plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2010 is $(0.9) million.

The weighted-average rate assumptions used to determine benefit obligations as of December 31, 2008 and 2009 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2008	2009	2008	2009
Discount rate—Salaried plan	6.00%	5.79%	N/A	N/A
Discount rate—USW plan	6.25%	5.72%	N/A	N/A
Discount rate—IUOE plan	5.75%	5.67%	N/A	N/A
Discount rate—Other Postretirement Benefits	N/A	N/A	5.75%	5.97%
Rate of compensation increase—Salaried plan	5.00%	5.00%	N/A	N/A
Rate of compensation increase—USW plan	4.50%	4.50%	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, 2007, 2008 and 2009 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2007	2008	2009	2007	2008	2009
Discount rate—Salaried plan	5.75%	6.50%	6.00%	N/A	N/A	N/A
Discount rate—USW plan	5.75%	6.50%	6.25%	N/A	N/A	N/A
Discount rate—IUOE plan	5.75%	6.50%	5.75%	N/A	N/A	N/A
Discount rate—Other Postretirement Benefits	N/A	N/A	N/A	6.00%	6.50%	5.75%
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%	4.50%	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	7.00%	7.00%	6.80%	N/A	N/A	N/A
Expected rate of return on plan assets—USW plan	7.00%	7.00%	6.80%	N/A	N/A	N/A
Expected rate of return on plan assets—IUOE plan	7.00%	7.00%	3.25%	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 2010 is 6.8% decreasing systematically to 4.0% by 2084 for pre-65 and post-65 year-old participants. The health care cost trend rate assumption has a significant effect on the amounts reported. As of December 31, 2009, 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	$ 245	$ 194
Change in postretirement benefit obligation	$2,712	$2,149

The fair value of the pension plan assets at December 31, 2009 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)
Cash	$ 23	$ 23	$—	$—
Domestic Equity Securities[a]:				
Small-cap fund	2,070	2,070	—	—
Mid-cap fund	4,702	4,702	—	—
Large-cap fund	6,193	6,193	—	—
International equity fund	7,630	7,630	—	—
Fixed Income Securities[a]:				
Intermediate-term bond funds	22,029	22,029	—	—
Long-term investment grade bond fund	6,426	6,426	—	—
Other:			—	—
Short-term investment fund	1,462	1,462	—	—
Group annuity contract	471	—	—	471
Fair value of plan assets	$51,006	$50,535	$—	$471

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

The fair value measurements using significant unobservable inputs (Level 3) were as follows (in thousands):

	Group Annuity Contract
Beginning balance at December 31, 2008	$442
Actual return on plan assets:	
Relating to assets still held at the reporting date	25
Purchases, sales and settlements	4
Ending balance at December 31, 2009	$471

The investment strategy for the 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:	
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 money market securities, certificates of deposit, commercial paper and municipal 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 which 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 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. The target allocation and actual weighted-average asset allocation percentages at December 31, 2008 and 2009 were as follows:

	2008		2009	
	Actual[(a)]	Target	Actual[(a)]	Target
Equity securities	30%	40%	40%	40%
Debt securities	59%	59%	57%	59%
Other	11%	1%	3%	1%

(a) Cash contributions of $9.1 million and $7.4 million were made to the pension plans in the 2008 and 2009 fiscal years, respectively. Amounts contributed in 2008 and 2009 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, 2008 and 2009 scheduled for investment in accordance with the target. Excluding these uninvested cash amounts, the actual allocation percentages at December 31, 2008 would have been 33% equity securities and 67% debt securities and at December 31, 2009, would have been 41% equity securities and 58% debt securities. In 2010, these uninvested cash amounts will be invested to bring the total asset allocation in line with the target allocation.

As of December 31, 2009, the benefit amounts expected to be paid through December 31, 2019 were as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2010	$ 2,791	$ 421
2011	3,093	505
2012	3,331	588
2013	3,331	653
2014	3,922	689
2015 through 2019	22,520	4,525

Contributions estimated to be paid into the plans in 2010 are $6.4 million and $0.4 million for the pension and other postretirement benefit plans, respectively.

13. Related Party Transactions

We own a 50% interest in a crude oil pipeline company and are paid a management fee for its operation. We received operating fees from this company of $0.7 million, $0.7 million and $0.8 million in 2007, 2008 and 2009, respectively. These fees were reported as affiliate management fee revenue on our consolidated statements of income.

Prior to the simplification, under a services agreement between Holdings, Holdings GP and Partners, Partners and Holdings reimbursed Holdings GP for the costs of employees necessary to conduct their respective operations and administrative functions. As part of the simplification, Holdings GP became our wholly-owned subsidiary; therefore, effective September 28, 2009, we no longer report transactions between us and Holdings GP as affiliate transactions. The payroll and benefits accrual associated with the aforementioned agreement at December 31, 2008 was $21.9 million and the long-term pension and benefits accrual at December 31, 2008 was $31.8 million.

Holdings historically reimbursed Partners for G&A expenses, excluding equity-based compensation, in excess of a G&A cap. The amount of G&A costs required to be reimbursed was $4.1 million and $1.6 million in 2007 and 2008, respectively. MGG Midstream Holdings, L.P. reimbursed Holdings for the same amounts Holdings reimbursed to Partners for these excess G&A expenses. Partners and Holdings recorded these reimbursements as a capital contribution from their respective general partners. No reimbursements were made under this agreement after 2008.

During 2007 and 2008, Partners and Holdings were allocated $2.1 million and $0.4 million, respectively, of non-cash G&A compensation expense, with a corresponding increase in owners' equity, for payments made by MGG Midstream Holdings, L.P. to one of Partners' executive officers.

The following table summarizes affiliate costs and expenses that are reflected in the accompanying consolidated statements of income (in thousands):

	Year Ended December 31,		
	2007	2008	2009
Holdings GP—allocated operating expenses	$81,184	$84,460	$69,523
Holdings GP—allocated G&A expenses	46,195	44,482	41,890
MGG Midstream Holdings, L.P.—allocated G&A expenses	2,149	440	—

Other Related Party Transactions

Because historical distributions paid by Partners prior to the simplification exceeded target levels as specified in its partnership agreement, until the completion of the simplification, Partners GP received approximately 50%, including its approximate 2% general partner interest, of any incremental cash distributed per Partners limited partner unit. Since Holdings owned Partners GP during that period, it benefitted from these distributions. In 2007, 2008 and prior to the simplification in September 2009, distributions paid to Partners GP by Partners based on Partners GP's general partner interest and incentive distribution rights totaled $70.3 million, $85.6 million and $70.4 million, respectively. Until December 3, 2008, the executive officers of Holdings GP collectively owned a direct interest in MGG Midstream Holdings, L.P. of approximately 4% (MGG Midstream Holdings, L.P. owned Holdings GP until December 3, 2008). The executive officers of Holdings GP, through their ownership in MGG Midstream Holdings, L.P., indirectly benefited from Partners' distributions and directly benefited from Holdings' distributions. As of December 31, 2009, our executive officers own less than 1% of our limited partner units.

14. Debt

Debt at December 31, 2008 and 2009 was as follows (in thousands):

	December 31, 2008	December 31, 2009	Weighted-Average Interest Rate at December 31, 2009(1)
Revolving credit facility	$ 70,000	$ 101,600	0.6%
6.45% Notes due 2014	249,681	249,732	6.3%
5.65% Notes due 2016	253,328	252,897	5.7%
6.40% Notes due 2018	261,555	260,340	5.9%
6.55% Notes due 2019	—	566,500	4.6%
6.40% Notes due 2037	248,921	248,935	6.3%
Total debt	$1,083,485	$1,680,004	

(1) Weighted-average interest rate includes the impact of interest rate swaps and the amortization of discounts and gains and losses realized on various hedges (see Note 15—Derivative Financial Instruments for detailed information).

The face value of our debt outstanding as of December 31, 2009 was $1,651.6 million. The difference between the face value and carrying value of the debt outstanding results from the unamortized portion of various fair value hedges and the unamortized discounts and premiums on debt issuances. At December 31, 2009, maturities of our debt were as follows: $0 in 2010 and 2011; $101.6 million in 2012; $0 in 2013; $250.0 million in 2014; and $1.3 billion thereafter.

Note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives of the associated notes.

Revolving Credit Facility. The total borrowing capacity under the revolving credit facility, which matures in September 2012, is $550.0 million. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. Additionally, a commitment fee is assessed at a rate from 0.05% to 0.125%, depending on our credit ratings. Borrowings under this facility are used for general purposes, including capital expenditures. As of December 31, 2009, $101.6 million was outstanding under this facility and $4.4 million was obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets.

6.45% Notes due 2014. In May 2004, we sold $250.0 million aggregate principal of 6.45% notes due 2014 in an underwritten public offering. The notes were issued for the discounted price of 99.8%, or $249.5 million.

5.65% Notes due 2016. In October 2004, we issued $250.0 million of 5.65% notes due 2016 in an underwritten public offering. The notes were issued for the discounted price of 99.9%, or $249.7 million. The outstanding principal amount of the notes was increased by $3.5 million and $3.1 million at December 31, 2008 and 2009, respectively, for the unamortized portion of a gain realized upon termination of a related interest rate swap (see Note 15—Derivative Financial Instruments).

6.40% Notes due 2018. In July 2008, we issued $250.0 million of 6.40% notes due 2018 in an underwritten public offering. The outstanding principal amount of the notes was increased by $11.6 million and $10.4 million at December 31, 2008 and 2009, respectively, for the unamortized portion of gains realized upon termination or discontinuation of hedge accounting treatment of associated interest rate swaps (see Note 15—Derivative Financial Instruments).

6.55% Notes due 2019. In June and August 2009, we issued $550.0 million of 6.55% notes due 2019 in underwritten public offerings. The notes were issued at a net premium of 103.4%, or $568.7 million. Net proceeds from these offerings, after underwriter discounts of $3.6 million and offering costs of $0.8 million, were $564.3 million. The net proceeds were used to repay, in total, $454.3 million of borrowings outstanding under our revolving credit facility ($338.4 million of which was related to the Longhorn acquisition), with the balance used for general purposes including capital expenditures. In connection with these offerings, we entered into interest rate swap agreements to effectively convert $250.0 million of these notes to floating-rate debt (see Note 15—Derivative Financial Instruments). The outstanding principal amount of the notes was decreased by $1.6 million at December 31, 2009 for the fair value of the associated interest rate swap agreements.

6.40% Notes due 2037. In April 2007, we issued $250.0 million of 6.40% notes due 2037 in an underwritten public offering. The notes were issued for the discounted price of 99.6%, or $248.9 million.

The revolving credit facility described above requires us to maintain a specified ratio of consolidated debt to EBITDA (as defined in the agreement) of no greater than 4.75 to 1.00. In addition, the revolving credit facility and the indentures under which our public notes were issued contain covenants that limit our ability to, among other things, incur indebtedness secured by certain liens or encumber our assets, engage in certain sale-leaseback transactions, and consolidate, merge or dispose of all or substantially all of our assets. We were in compliance with these covenants as of December 31, 2009. During 2009, the terms of the revolving credit facility were amended to exclude the financial impact of unrealized gains and losses of derivative agreements from the calculation of consolidated debt to EBITDA.

The revolving credit facility and notes described above are senior indebtedness.

During the years ending December 31, 2007, 2008 and 2009, total cash payments for interest on all indebtedness, including the impact of related interest rate swap agreements, net of amounts capitalized, were $59.2 million, $49.3 million and $64.3 million, respectively.

15. Derivative Financial Instruments

Commodity Derivatives

Our petroleum products blending activities generate gasoline products and we can estimate the timing and quantities of sales of these products. We use a combination of forward sales contracts and NYMEX agreements to lock in most of the gross margins realized from our blending activities. We account for the forward sales contracts as normal sales.

As discussed in Note 9—Product Sales Revenues, we began using NYMEX contracts during the third quarter of 2008 as economic hedges against changes in the price of petroleum products it expected to sell from its petroleum products blending activities. In 2009, we began using NYMEX contracts as economic hedges against the changes in value of the petroleum products associated with linefill petroleum products purchased in connection with the Longhorn acquisition. In 2008 and through the second quarter of 2009, none of the NYMEX contracts we entered into qualified for hedge accounting treatment under ASC 815-30, *Derivatives and Hedging*. However, beginning in July 2009, because of other agreements that we entered into, some of the NYMEX contracts associated with our petroleum products blending activities qualified for hedge accounting treatment and have been recorded as cash flow hedges. None of the NYMEX contracts we used as economic hedges of the linefill of the pipeline purchased with the Longhorn acquisition qualified for hedge accounting treatment. All of the open NYMEX contracts at December 31, 2009 associated with our petroleum products blending activities mature within the next twelve months. During 2009, we entered into NYMEX contracts for 0.2 million barrels which qualified as cash flow hedges.

At December 31, 2009, the fair value of open NYMEX contracts, representing 2.1 million barrels of petroleum products, was a net liability of $10.4 million, of which $9.2 million was recorded as energy commodity derivative contracts and $1.2 million was recorded as noncurrent liabilities on our consolidated balance sheet. These open NYMEX contracts mature between January 2010 and August 2011. At December 31, 2009, we had made margin deposits of $17.9 million for these contracts, which were recorded as energy commodity derivatives deposit on our consolidated balance sheet. We have the right to offset the fair value of our open NYMEX contracts against our margin deposits under a master netting arrangement with our counterpart; however, we have elected to separately disclose these amounts on our consolidated balance sheet.

Interest Rate Derivatives

In June and August 2009, we entered into a total of $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. We account for these agreements as fair value hedges. These agreements effectively convert $250.0 million of our 6.55% fixed-rate notes to floating-rate debt. Under the terms of the agreements, we receive the 6.55% fixed rate of the notes and pay six-month LIBOR in arrears plus 2.18% for the $150.0 million swaps and 2.34% for the other $100.0 million. The agreements terminate in June 2019, which is the maturity date of the related notes. Payments settle in January and July each year. During each period, we record the impact of these swaps based on the forward LIBOR curve. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR will result in an adjustment to our interest expense. These interest rate derivatives contain credit-risk-related contingent features. These contingent features provide that in the event of our default on any obligation of $25.0 million or more or a merger in which our credit rating becomes “materially weaker”, which would generally be interpreted as falling below investment grade, the counterparties to our interest rate derivatives agreements could terminate those agreements and require immediate settlement. As of December 31, 2009, the $100.0 million interest rate swaps were in a net liability position of $0.1 million, of which $1.4 million was recorded as other current assets and $1.5 million was recorded as other noncurrent liabilities on our consolidated balance sheet. As of December 31, 2009, the $150.0 million interest rate swaps were in a net gain position of $2.9 million, of which $3.0 million was recorded as other current assets and $0.1 million was recorded as other noncurrent liabilities on our consolidated balance sheet.

The following interest rate derivatives were settled during 2009:

- In July 2008, we entered into a $50.0 million interest rate swap agreement (“Derivative A”) to hedge against changes in the fair value of a portion of the $250.0 million of 6.40% notes due 2018. Derivative A effectively converted $50.0 million of those notes from a 6.40% fixed rate to a floating rate of six-month LIBOR plus 1.83%. We originally accounted for Derivative A as a fair value hedge. In December 2008, in order to capture the economic value of Derivative A at that time, we entered into an offsetting derivative, as described below, and discontinued hedge accounting for Derivative A. The $5.4 million fair value of Derivative A at that time was recorded as an increase to long-term debt, which is being amortized over the remaining life of the 6.40% fixed-rate notes due 2018. In December 2009, this swap was terminated and we received cash proceeds of $3.4 million.

- In December 2008, concurrent with the discontinuance of hedge accounting for Derivative A, we entered into an offsetting $50.0 million interest rate swap agreement with a different financial institution pursuant to which it paid a fixed rate of 6.40% and received a floating rate of six-month LIBOR plus 3.23%. We entered into this agreement to offset changes in the fair value of Derivative A, excluding adjustments due to changes in counterparty credit risks. This agreement was not designated as a hedge for accounting purposes. In December 2009, this swap was terminated and we received cash proceeds of $2.0 million.

The following financial instruments designated as hedges were settled during 2008:

- In July 2008, we entered into a $50.0 million interest rate swap agreement to hedge against changes in the fair value of a portion of the $250.0 million of 6.40% notes due 2018. We accounted for this agreement as a fair value hedge. This agreement effectively converted $50.0 million of our 6.40% fixed-rate notes to floating-rate debt. In December 2008, we terminated and settled this interest rate swap agreement and received $6.3 million, which was recorded as an adjustment to long-term debt and is being amortized over the remaining life of the 6.40% fixed-rate notes.
- In October 2004, we entered into an interest rate swap agreement to hedge against changes in the fair value of a portion of the $250.0 million of senior notes due 2016. We accounted for this agreement as a fair value hedge. This agreement effectively converted $100.0 million of our 5.65% fixed-rate senior notes to floating-rate debt. In May 2008, we terminated and settled this interest rate swap agreement and received $3.8 million, which was recorded as an adjustment to long-term debt and is being amortized over the remaining life of the notes.
- In January 2008, we entered into a total of $200.0 million of forward-starting interest rate swap agreements to hedge against the variability of future interest payments on debt that we anticipated issuing no later than June 2008. Proceeds of the anticipated debt issuance were expected to be used to refinance borrowings on our revolving credit facility. In April 2008, we terminated and settled these interest rate swap agreements and received $0.2 million, which was recorded to other income on our consolidated statement of income.

The following financial instruments designated as hedges were settled during 2007:

- In September and November 2006, we entered into forward-starting interest rate swap agreements to hedge against the variability of future interest payments on $250.0 million of debt we issued in April 2007. We accounted for these agreements as cash flow hedges. These agreements were terminated and settled in April 2007, in conjunction with our public offering of $250.0 million of notes. We received $5.5 million from the settlement of these agreements, of which a gain of $5.0 million was recorded to other comprehensive income that, along with $0.2 million gain recognized in 2006, we are amortizing against interest expense over the life of the notes, $0.2 million was recorded as an adjustment to other current assets and $0.3 million was considered ineffective and recorded as other income on our consolidated statement of income.
- During May 2004, we entered into certain interest rate swap agreements with notional amounts of $250.0 million to hedge against changes in the fair value of a portion of its pipeline notes. We

terminated these agreements in May 2007 in conjunction with the repayment of these notes, resulting in payments totaling $1.1 million to the hedge counterparties, of which $0.9 million was recorded to other expense and $0.2 million was recorded as a reduction of accrued interest.

The changes in derivative gains (losses) included in AOCL for the years ended December 31, 2007, 2008 and 2009 were as follows (in thousands):

Derivative Gains (Losses) Included in AOCL	Year Ended December 31, 2007	2008	2009
Beginning balance	$ (782)	$3,817	$ 3,653
Net gain on interest rate swap agreements	5,018	—	—
Net loss on commodity hedges	—	—	(6,804)
Reclassification of net gain on cash flow hedges to interest expense	(419)	(164)	(164)
Reclassification of net loss on commodity hedges to product sales revenues	—	—	5,058
Ending balance	$3,817	$3,653	$ 1,743

As of December 31, 2009, the net gain (loss) estimated to be classified to interest expense and product sales revenues over the next twelve months from AOCL is approximately $0.2 million and $(1.7) million, respectively.

The following is a summary of the current impact of our historical derivative activity on long-term debt resulting from the termination of or the discontinuance of hedge accounting treatment of fair value hedges as of and for the year ended December 31, 2009 (in thousands):

Hedge	Total Gain Realized	As of December 31, 2009: Unamortized Amount Recorded in Long-term Debt	Year Ended December 31, 2009: Amount Reclassified to Interest Expense from Long-term Debt
Fair value hedges (date executed):			
Interest rate swaps 6.40% Notes (July 2008)	$11,652	$10,358	$(1,216)
Interest rate swaps 5.65% Notes (October 2004)	3,830	3,093	(455)
Total fair value hedges		$13,451	$(1,671)

The following is a summary of the effect of derivatives accounted for under ASC 815-25, *Derivatives and Hedging—Fair Value Hedges*, that were designated as hedging instruments on our consolidated statement of income for the year ended December 31, 2009 (in thousands):

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	$4,446	$(15,917)

The following is a summary of the effect of derivatives accounted for under ASC 815-30, *Derivatives and Hedging—Cash Flow Hedges*, that were designated as hedging instruments on our consolidated statement of income for the year ended December 31, 2009 (in thousands):

	Effective Portion		
Derivative Instrument	**Amount of Gain (Loss) Recognized in AOCL on Derivative**	**Location of Gain (Loss) Reclassified from AOCL into Income**	**Amount of Gain (Loss) Reclassified from AOCL into Income**
Interest rate swap agreements	$ —	Interest expense	$ 164
NYMEX commodity contracts	(6,804)	Product sales revenues	(5,058)
Total cash flow hedges	$(6,804)	Total	$(4,894)

There was no ineffectiveness recognized on the financial instruments disclosed in the above table during the year ended December 31, 2009.

The following is a summary of the effect of derivatives accounted for under ASC 815-10-35; Paragraph 2, *Derivatives and Hedging—Overall—Subsequent Measurement*, that were not designated as hedging instruments on our consolidated statement of income for the year ended December 31, 2009 (in thousands):

Derivative Instrument	Location of Gain (Loss) Recognized on Derivative	Amount of Gain (Loss) Recognized on Derivative
Interest rate swap agreements	Other income	$ 279
NYMEX commodity contracts	Product sales revenues	(33,532)
	Total	$(33,253)

The following is a summary of the amounts included in our consolidated balance sheet of the fair value of derivatives accounted for under ASC 815, *Derivatives and Hedging,* that were designated as hedging instruments as of December 31, 2009 (in thousands):

	Asset Derivatives		Liability Derivatives	
Derivative Instrument	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Interest rate swap agreements, current portion	Other current assets	$4,446	Other current liabilities	$ —
Interest rate swap agreements, noncurrent portion	Other noncurrent assets	—	Other noncurrent liabilities	1,649
NYMEX commodity contracts	Energy commodity derivative contracts	—	Energy commodity derivative contracts	1,211
	Total	$4,446	Total	$2,860

The following is a summary of the amounts included in our consolidated balance sheet 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, 2009 (in thousands):

	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivative contracts	$—	Energy commodity derivative contracts	$8,046
NYMEX commodity contracts	Other noncurrent assets	—	Other noncurrent liabilities	1,146
	Total	$—	Total	$9,192

16. Leases

Leases—Lessee. We lease land, office buildings, tanks and terminal equipment at various locations to conduct our respective 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 in the normal course of business, expiring leases will generally be renewed. Leases are evaluated at inception or at any subsequent material modification and, depending on the lease terms, are classified as either capital leases or operating leases, as appropriate under ASC 840, *Leases*. Rent expense is recognized on a straight-line basis over the life of the lease. Total rent expense was $4.6 million, $4.6 million and $5.2 million for the years ended December 31, 2007, 2008 and 2009, respectively. Future minimum annual rentals under non-cancelable operating leases as of December 31, 2009, were as follows (in thousands):

2010	$ 3,057
2011	3,020
2012	2,524
2013	1,577
2014	1,396
Thereafter	9,634
Total	$21,208

Leases—Lessor. We have entered into capacity and storage leases with remaining terms from one to 10 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, 2009, were as follows (in thousands):

2010	$159,399
2011	138,578
2012	114,077
2013	91,001
2014	79,618
Thereafter	219,164
Total	$801,837

In December 2001, Partners purchased an 8.5-mile natural gas liquids pipeline in northeastern Illinois from Aux Sable Liquid Products L.P. ("Aux Sable") for $8.9 million. Partners then entered into a long-term lease arrangement under which Aux Sable was the sole lessee of these assets. Partners accounted for this transaction as a direct financing lease. Aux Sable re-acquired this pipeline during 2009 and the lease was settled when we received $6.1 million in October 2009, which was the remaining balance due at that time. The net investment under direct financing lease arrangements as of December 31, 2008 was as follows (in thousands):

Total minimum lease payments receivable	$10,234
Less: Unearned income	3,393
Recorded net investment in direct financing leases	$ 6,841

The net investment in this direct financing lease as of December 31, 2008 was classified in the consolidated balance sheets as follows (in thousands):

Classification of direct financing leases:	
Current accounts receivable	$ 622
Noncurrent accounts receivable	6,219
Total	$6,841

17. Long-Term Incentive Plan

Plan Description

We have a long-term incentive plan ("LTIP") for certain of our employees and for directors of our general partner. The LTIP primarily consists of phantom units and permits the grant of awards covering an aggregate of 3.2 million of our limited partner units. The remaining units available under the LTIP at December 31, 2009 total 1.3 million. The compensation committee of our general partner's board of directors (the "Compensation Committee") administers the LTIP and has approved the unit awards discussed below.

Vested Unit Awards

Grant Date	Unit Awards Granted	Forfeitures	Adjustments to Unit Awards for Attaining Above-Target Financial Results	Vested Limited Partner Units	Vesting Date	Value of Unit Awards on Vesting Date (Millions)
February 2004	159,024	14,648	140,794	285,170	12/31/06	$11.0
February 2005	160,640	11,348	149,292	298,584	12/31/07	$12.9
June 2006	1,170	—	1,170	2,340	12/31/07	$ 0.1
February 2006	168,105	13,730	154,143	308,518	12/31/08	$ 9.3
Various 2006	9,201	2,640	6,561	13,122	12/31/08	$ 0.4
March 2007	2,640	—	—	2,640	12/31/08	$ 0.1
January 2007	159,691	3,776	62,190	218,105	12/31/09	$ 9.5

In January 2007, the cumulative amounts of the February 2004 award grants were settled by issuing 184,905 limited partner units and distributing those units to the plan participants. The difference between the limited partner units issued to the participants and the total units accrued for represented the minimum tax withholdings associated with this award settlement. Associated tax withholdings and employer taxes totaling $4.4 million were paid in January 2007.

In January 2008, the cumulative amounts of the February 2005 and June 2006 award grants were settled by issuing 196,856 limited partner units and distributing those units to the participants. The difference between the limited partner units issued to the participants and the total units accrued for represented the minimum tax withholdings associated with this award settlement. Associated tax withholdings and employer taxes totaling $5.1 million were paid in January 2008.

In January 2009, the cumulative amounts of the remaining 2006 and March 2007 award grants were settled by issuing 209,320 limited partner units and distributing those units to the participants. The difference between the limited partner units issued to the participants and the total units accrued for represented the minimum tax withholdings associated with this award settlement. Associated tax withholdings and employer taxes totaling $4.0 million were paid in January 2009.

In January 2010, the cumulative amounts of the January 2007 award grants were settled by issuing 140,317 limited partner units and distributing those units to the participants (see Note 25—Subsequent Events). There was no impact on the consolidated cash flows associated with these award grants for the periods presented in this report. The difference between the limited partner units issued to the participants and the total units accrued for represented the minimum tax withholdings associated with this award settlement. Associated tax withholdings and employer taxes totaling $3.9 million were paid in January 2010.

Performance Based Unit Awards

The incentive awards discussed below are subject to forfeiture if employment is terminated for any reason other than retirement, death or disability prior to the vesting date. If an award recipient retires, dies or becomes disabled prior to the end of the vesting period, the recipient's award grant is prorated based upon the completed months of employment during the vesting period and the award is settled at the end of the vesting period. Our agreement with the LTIP participants requires the LTIP awards described below to be paid out in our limited partner units. The award grants do not have an early vesting feature except under certain circumstances following a change in control of our general partner.

On December 3, 2008, Holdings purchased its general partner. When this transaction closed, a change in control occurred as defined in the LTIP. Even though a change in control occurred, participants in the LTIP must resign voluntarily for good reason or be terminated involuntarily for other than performance reasons within two years of December 3, 2008 in order to receive enhanced LTIP payouts. On September 30, 2009, pursuant to the simplification (see Note 2—Simplification), our general partner became our wholly-owned subsidiary, which resulted in a change in control as defined in the LTIP. This change of control could impact the payouts relative to the LTIP awards issued during 2008. The 2009 LTIP awards contain provisions which specifically exclude the change in control that resulted from the simplification. Even though a change in control has occurred, participants in the LTIP must resign voluntarily for good reason or be terminated involuntarily for other than performance reasons within two years of September 30, 2009 in order to receive enhanced LTIP payouts. As of December 31, 2009, there have been no enhanced LTIP payouts associated with either the change of control that occurred in December 2008 or September 2009.

For each of the award grants listed below, the payout calculation for 80% of the unit awards will be based solely on the attainment of a financial metric established by the Compensation Committee. This portion of the award grants has been accounted for as equity. The payout calculation for the remaining 20% of the unit awards will be based on both the attainment of a financial metric and the individual employee's personal performance as determined by the Compensation Committee. This portion of the award grants has been accounted for as a liability.

The table below summarizes the performance based unit awards granted by the Compensation Committee that had not vested as of December 31, 2009. There was no impact to the consolidated cash flows associated with these award grants for the periods presented in this report.

Grant Date	Unit Awards Granted	Estimated Forfeitures	Adjustment to Unit Awards in Anticipation of Achieving Above/ (Below) Target Financial Results	Total Unit Award Accrual	Vesting Date	Unrecognized Compensation Expense (Millions)(1)	Intrinsic Value of Unvested Awards at December 31, 2009 (Millions)
2008 Awards . . .	189,832	5,695	(69,972)	114,165	12/31/10	$1.2	$ 4.9
2009 Awards . . .	275,994	8,281	—	267,713	12/31/11	4.1	11.6
Total	465,826	13,976	(69,972)	381,878		$5.3	$16.5

(1) Unrecognized compensation expense will be recognized over the remaining vesting periods of the awards.

At its February 2009 meeting, the Compensation Committee adjusted the threshold, target and stretch performance levels for the 2008 awards to reflect the downturn in the economic environment. The Compensation Committee felt that the modifications were necessary to ensure that the motivational and retention features of the awards remain potent in the current economic environment and maintain the link necessary to encourage our key employees to maximize our long-term financial results. At December 31, 2008, the accrual for the payout of the 2008 awards was 30% and the accrual for the payout of the adjusted 2008 unit awards at December 31, 2009 was 62%, or $2.3 million.

Retention Awards

The retention awards below are subject to forfeiture if employment is terminated or the employee resigns from their current position for any reason prior to the applicable vesting date. The award grants do not have an early vesting feature. The award grants listed below were accounted for as equity.

Grant Date	Unit Awards Granted	Estimated Forfeitures	Total Unit Award Accrual	Vesting Date	Unrecognized Compensation Expense (Millions)(1)	Intrinsic Value of Unvested Awards at December 31, 2009 (Millions)
Various 2008	9,248	278	8,970	12/31/10	$0.1	$0.4
March 2009	5,000	150	4,850	12/31/10	0.1	0.2
Various 2008	40,315	1,814	38,501	12/31/11	0.5	1.7
March 2009	1,373	62	1,311	12/31/11	*	0.1
November 2009	1,106	50	1,056	12/31/12	*	*
	57,042	2,354	54,688		$0.7	$2.4

(1) Unrecognized compensation expense will be recognized over the remaining vesting periods of the awards.
* Amounts are less than $0.1.

Fair Value of Unit Awards

	December 31, 2009			
	2007 Awards	2008 Awards	2009 Awards	Retention Awards
Weighted-average per unit grant date fair value of equity awards[(a)]	$32.00	$27.77	$19.61	$24.20
December 31, 2009 per unit fair value of liability awards[(b)]	$43.33	$40.45	$37.43	$ —

(a) Approximately 80% of the unit awards are accounted for as equity (see *Performance Based Unit Awards* above). Fair value is calculated as our unit price on the grant date less the present value of estimated cash distributions during the vesting period.
(b) Approximately 20% of the unit awards are accounted for as liabilities (see *Performance Based Unit Awards* above). Fair value is calculated as our unit price at the end of each accounting period less the present value of estimated cash distributions during the remaining portion of the vesting period.

Compensation Expense Summary

Equity-based incentive compensation expense excluding amounts for directors (discussed below) for 2007, 2008 and 2009 was as follows (in thousands):

	Year Ended December 31, 2007		
	Equity Method	Liability Method	Total
2005 awards	$ —	$5,721	$5,721
2006 awards	2,216	955	3,171
2007 awards	860	242	1,102
Total	$3,076	$6,918	$9,994

	Year Ended December 31, 2008		
	Equity Method	Liability Method	Total
2005 awards	$ —	$ 26	$ 26
2006 awards	2,509	378	2,887
2007 awards	990	127	1,117
2008 awards	457	82	539
Retention awards	182	—	182
Total	$4,138	$ 613	$4,751

	Year Ended December 31, 2009		
	Equity Method	Liability Method	Total
2007 awards	$3,842	$1,526	$5,368
2008 awards	1,243	534	1,777
2009 awards	1,400	668	2,068
Retention awards	409	—	409
Total	$6,894	$2,728	$9,622

Director Equity-Based Compensation Expense

Long-term incentive awards were granted to independent members of the board of directors of Holdings GP and Partners GP prior to the simplification and to the independent members of the board of directors of our general partner after the simplification (which was a combination of Partners GP's and Holdings GP's boards of directors—See Note 2—Simplification) pursuant to the respective long-term incentive plans. Prior to the simplification, Holdings GP's and Partners GP's independent directors could elect and, after the simplification, our independent directors can elect to defer payment of all or a portion of their compensation. All compensation amounts deferred were credited to the applicable director's account in the form of phantom limited partner units of each director's respective entity, with distribution equivalent rights. On September 28, 2009, the deferred phantom limited partner units of the Holdings GP independent directors were converted to phantom limited partner units in us at the exchange rate of 0.6325 to 1.0. This adjustment was applied retrospectively to all periods presented in the table below. Phantom limited partner units earned by our independent directors and the related compensation expense recognized are provided in the table below. The unit and compensation amounts below include amounts credited to the director's account for distribution equivalents earned (in thousands, except unit amounts).

	Year Ended December 31,		
	2007	2008	2009
Phantom units earned by independent directors	10,576	13,950	14,123
Total equity-based director compensation expense	$ 337	$ 507	$ 435

18. 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.

Management believes that investors benefit from having access to the same financial measures that they use. 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 by 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. Operating profit includes expense items, such as depreciation and amortization expense and G&A costs, that management does not consider when evaluating the core profitability of our operations.

	Year Ended December 31, 2007				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
			(in thousands)		
Transportation and terminals revenues	$ 460,709	$132,693	$18,287	$(2,908)	$ 608,781
Product sales revenues	692,355	17,209	—	—	709,564
Affiliate management fee revenue	712	—	—	—	712
Total revenues	1,153,776	149,902	18,287	(2,908)	1,319,057
Operating expenses	178,894	56,181	21,282	(5,422)	250,935
Product purchases	626,194	8,233	—	(518)	633,909
Equity earnings	(4,027)	—	—	—	(4,027)
Operating margin (loss)	352,715	85,488	(2,995)	3,032	438,240
Depreciation and amortization expense	51,936	23,078	1,094	3,032	79,140
G&A expenses	54,016	18,165	2,678	—	74,859
Operating profit (loss)	$ 246,763	$ 44,245	$ (6,767)	$ —	$ 284,241
Segment assets	$1,692,688	$661,164	$32,444		$2,386,296
Corporate assets					30,635
Total assets					$2,416,931
Goodwill	$ —	$ 11,902	$ —		$ 11,902
Additions to long-lived assets	$ 92,692	$ 92,766	$ 2,002		$ 187,460
Equity investments	$ 24,324	$ —	$ —		$ 24,324

	Year Ended December 31, 2008				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
			(in thousands)		
Transportation and terminals revenues	$ 478,473	$141,129	$22,704	$(3,496)	$ 638,810
Product sales revenues	543,694	30,401	—	—	574,095
Affiliate management fee revenue	733	—	—	—	733
Total revenues	1,022,900	171,530	22,704	(3,496)	1,213,638
Operating expenses	197,670	59,130	14,044	(5,973)	264,871
Product purchases	429,294	8,279	—	(1,006)	436,567
Gain on assignment of supply agreement	(26,492)	—	—	—	(26,492)
Equity earnings	(4,067)	—	—	—	(4,067)
Operating margin	426,495	104,121	8,660	3,483	542,759
Depreciation and amortization expense	54,849	26,999	1,170	3,483	86,501
G&A expenses	52,874	17,313	3,115	—	73,302
Operating profit	$ 318,772	$ 59,809	$ 4,375	$ —	$ 382,956
Segment assets	$1,714,558	$778,477	$38,561		$2,531,596
Corporate assets					69,112
Total assets					$2,600,708
Goodwill	$ 2,864	$ 11,902	$ —		$ 14,766
Additions to long-lived assets	$ 156,266	$144,620	$ 5,536		$ 306,422
Equity investments	$ 23,190	$ —	$ —		$ 23,190

	Year Ended December 31, 2009				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
			(in thousands)		
Transportation and terminals revenues	$ 494,165	$169,939	$19,862	$(5,021)	$ 678,945
Product sales revenues	320,100	14,365	—	—	334,465
Affiliate management fee revenue	761	—	—	—	761
Total revenues	815,026	184,304	19,862	(5,021)	1,014,171
Operating expenses	183,929	64,388	16,196	(6,878)	257,635
Product purchases	275,880	6,393	—	(1,982)	280,291
Equity earnings	(3,431)	—	—	—	(3,431)
Operating margin	358,648	113,523	3,666	3,839	479,676
Depreciation and amortization expense	59,606	32,306	1,465	3,839	97,216
G&A expenses	60,846	20,859	2,344	—	84,049
Operating profit (loss)	$ 238,196	$ 60,358	$ (143)	$ —	$ 298,411
Segment assets	$2,210,913	$879,587	$36,191		$3,126,691
Corporate assets					36,457
Total assets					$3,163,148
Goodwill	$ 2,864	$ 11,902	$ —		$ 14,766
Additions to long-lived assets	$ 392,767	$125,564	$ 276		$ 518,607
Equity investments	$ 22,054	$ —	$ —		$ 22,054

The increase in segment assets from 2008 to 2009 resulted primarily from the Longhorn acquisition during third quarter 2009 (see Note 7—Acquisitions).

19. Commitments and Contingencies

Environmental Liabilities. Liabilities recognized for estimated environmental costs were $41.8 million and $34.4 million at December 31, 2008 and December 31, 2009, 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 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 (credits) were $10.0 million, $(1.4) million and $7.3 million in 2007, 2008 and 2009, respectively. Environmental expenses for 2008 included the impact of a favorable settlement of a civil penalty related to historical product releases, which resulted in the reduction of our environmental liability accrual by $12.1 million.

In February 2007, we received notice from the Department of Justice ("DOJ") that the Environmental Protection Agency ("EPA") had requested the DOJ to initiate a lawsuit alleging violations of Sections 301 and 311 of the Clean Water Act with respect to two releases of anhydrous ammonia from our ammonia pipeline system which was operated by a third party at the time of the releases. In March 2007, we also received a demand from the third-party operator for defense and indemnification. In October 2009, we paid a penalty of $3.7 million to the EPA and agreed to perform certain operational enhancements. Further, we settled the third-party operator defense and indemnification for $0.8 million in December 2009.

Unrecognized Contingent Liability: Clean Air Act. Section 185 of the Clean Air Act requires each state to assess fees against major stationary emission sources in "severe" or "extreme" non-attainment areas. During 2009, the Texas Commission on Environmental Quality ("TCEQ"), in response to an EPA request, issued proposed rules which, if adopted as proposed, may result in fees assessed against our Galena Park, Texas terminal for the 2008 and 2009 calendar years of up to $8.1 million and $4.8 million, respectively.

In recent guidance, the EPA has indicated that a Section 185 fee program is not necessary for areas that have obtained the ozone standard as demonstrated through three consecutive years of monitoring data. Based on the monitoring data for the Houston/Galveston/Brazoria, Texas area prepared by the TCEQ, which indicates that the area obtained the ozone standard for past three consecutive years, management believes the mostly likely outcome will be that the EPA will recognize that the area has attained the ozone standard and that no fees will be assessed. However, management believes it is reasonably possible that the TCEQ could adopt its rules as proposed. Management believes that should the TCEQ adopt its proposed rules, because of special circumstances, the fees that would ultimately be assessed against our facility could be substantially reduced from the amounts described above. At December 31, 2009, we had no amounts accrued for this matter.

Environmental Receivables. Receivables from insurance carriers related to environmental matters were $4.5 million and $3.9 million at December 31, 2008 and December 31, 2009, respectively.

Unrecognized Product Gains. Our petroleum products terminals operations generate product overages and shortages that result from metering inaccuracies, product evaporation or expansion, product releases and product contamination. Most of the contracts we have with our customers state that we bear the risk of loss (or gain) from these conditions. When our petroleum products terminals experience net product shortages, we recognize expense for those losses in the periods in which they occur. When our petroleum products terminals experience net product overages, we have product on hand for which we have no cost basis. Therefore, these net overages are not recognized in our financial statements until the associated barrels are either sold or used to offset product losses. The net unrecognized product overages for our petroleum products terminals operations had a market value of approximately $5.1 million as of December 31, 2009. However, the actual amounts we will recognize in future periods will depend on product prices at the time the associated barrels are either sold or used to offset future product losses.

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

20. Quarterly Financial Data (unaudited)

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

2008	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$346,706	$273,127	$292,193	$301,612
Operating margin	140,610	142,418	122,766	136,965
Total costs and expenses	272,296	172,417	210,466	206,062
Net income	89,355	90,329	69,354	81,065
Net income allocated to limited partners' interest	18,024	31,308	18,052	20,349
Basic and diluted net income per limited partner unit	0.45	0.79	0.46	0.51
2009				
Revenues	$212,926	$208,220	$239,770	$353,255
Operating margin	100,348	107,321	119,373	152,634
Total costs and expenses	157,385	145,249	166,380	250,177
Net income	41,170	49,138	54,215	81,952
Net income attributable to limited partners' interest	12,022	14,611	18,161	81,952
Basic and diluted net income per limited partner unit	0.30	0.37	0.43	0.77

First-quarter 2009 revenues and net income were unfavorably impacted by $18.4 million of unrealized losses on NYMEX agreements. Second-quarter 2009 revenues and net income were unfavorably impacted by $19.1 million of unrealized losses on NYMEX agreements. In September 2009, we completed the simplification (see Note 2—Simplification). Following the simplification, all of our net income was allocated to the limited partners.

First-quarter 2008 net income was favorably impacted by the $26.5 million gain recognized from an assignment of a supply agreement. Second-quarter 2008 net income was favorably impacted by a $12.1 million reduction in operating expenses when an environmental matter was settled for less than amounts previously accrued. Third-quarter 2008 revenues and net income were favorably impacted by $12.2 million of unrealized gains on NYMEX agreements. Fourth-quarter revenues and net income were favorably impacted by $8.0 million of unrealized gains on outstanding NYMEX agreements and net income was unfavorably impacted by $28.6 million of lower-of-average-cost-or-market adjustments.

21. 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 in the balance sheet approximate fair value due to the short-term maturity or variable rates of these instruments.

Energy commodity derivatives deposit. This asset (liability) represents a short-term deposit we paid (held) associated with our energy commodity derivative contracts. The carrying amount reported in the balance sheet approximates fair value as the deposits paid (held) change daily in relation to the associated contracts.

Long-term receivables. Fair value was determined by estimating the present value of future cash flows using a risk-free rate of interest.

Energy commodity derivative contracts. The carrying amounts reported in the balance sheet represent fair value of the asset (liability). See Note 15—Derivative Financial Instruments.

Debt. The fair value of our publicly traded notes, excluding the value of interest rate swaps qualifying as fair value hedges, was based on the prices of those notes at December 31, 2008 and 2009. The carrying amount of borrowings under our revolving credit facility approximates fair value due to the variable rates of that instrument.

Interest rate swaps. Fair value was determined based on an assumed exchange, at each period end, in an orderly transaction with the financial institution counterparties of the interest rate derivative agreements.

The following table reflects the carrying amounts and fair values of our financial instruments as of December 31, 2008 and 2009 (in thousands):

	December 31, 2008		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 37,912	$ 37,912	$ 4,168	$ 4,168
Energy commodity derivative contracts (current)	20,200	20,200	(9,257)	(9,257)
Energy commodity derivative contracts (non-current)	—	—	(1,146)	(1,146)
Long-term receivables	7,390	5,249	618	589
Energy commodity derivatives deposit	(18,994)	(18,994)	17,943	17,943
Debt	1,083,485	934,975	1,680,004	1,777,064
Interest rate swaps	5,772	5,772	2,797	2,797

Fair Value Measurements

The following tables summarize the fair value measurements of our NYMEX commodity contracts and interest rate swap agreements as of December 31, 2008 and 2009, based on the three levels established by ASC 820-10-50; Paragraph 2, *Fair Value Measurements and Disclosures—Overall—Disclosure* (in thousands):

		Asset Fair Value Measurements as of December 31, 2008 using:		
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Energy commodity derivative contracts	$20,200	$20,200	$ —	$—
Interest rate swap agreements	5,772	—	5,772	—

		Asset Fair Value Measurements as of December 31, 2009 using:		
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Energy commodity derivative contracts (current)	$(9,257)	$(9,257)	$ —	$—
Energy commodity derivative contracts (non-current)	(1,146)	(1,146)	—	—
Interest rate swap agreements	2,797	—	2,797	—

22. Distributions

Distributions paid by Partners prior to the simplification during 2007, 2008 and 2009 were as follows (in thousands, except per unit amounts):

Payment Date	Per Unit Cash Distribution Amount	Limited Partner Units	General Partner[(a)]	Total Cash Distribution
02/14/07	$0.60250	$ 40,094	$16,197	$ 56,291
05/15/07	0.61625	41,009	17,112	58,121
08/14/07	0.63000	41,924	18,027	59,951
11/14/07	0.64375	42,839	18,942	61,781
Total	$2.49250	$165,866	$70,278	$236,144
02/14/08	$0.65750	$ 43,884	$19,909	$ 63,793
05/15/08	0.67250	44,885	20,910	65,795
08/14/08	0.68750	45,886	21,911	67,797
11/14/08	0.70250	46,887	22,912	69,799
Total	$2.72000	$181,542	$85,642	$267,184
02/13/09	$0.71000	$ 47,537	$23,478	$ 71,015
05/15/09	0.71000	47,537	23,478	71,015
08/14/09	0.71000	47,537	23,478	71,015
Total	$2.13000	$142,611	$70,434	$213,045

(a) Includes amounts paid to Partners GP for its incentive distribution rights.

Distributions paid by Holdings prior to simplification during 2007, 2008 and 2009 were as follows (in thousands, except per unit amounts):

Payment Date	Per Unit Cash Distribution Amount[(a)]	Limited Partner Units	General Partner	Total Cash Distribution
02/14/07	$0.38893	$15,411	$ 2	$15,413
05/15/07	0.41344	16,382	2	16,384
08/14/07	0.43636	17,291	2	17,293
11/14/07	0.45850	18,168	3	18,171
Total	$1.69723	$67,252	$ 9	$67,261
02/14/08	$0.48538	$19,232	$ 3	$19,235
05/15/08	0.50988	20,204	3	20,207
08/14/08	0.53360	21,143	3	21,146
11/14/08	0.55968	22,177	3	22,180
Total	$2.08854	$82,756	$ 12	$82,768
02/13/09	$0.56759	$22,490	$—	$22,490
05/15/09	0.56759	22,490	—	22,490
08/14/09	0.56759	22,490	—	22,490
Total	$1.70277	$67,470	$—	$67,470

(a) Restated for the reverse unit split that occurred in 2009 (See Note 2—Simplification).

Distributions paid in 2009 after the simplification were as follows (in thousands, except per unit amounts):

Payment Date	Per Unit Cash Distribution Amount	Limited Partner Units Outstanding	Total Cash Distribution
11/13/09	$0.71	106,588	$75,677

Total distributions paid were as follows (in thousands):

	Year Ended December 31,		
	2007	2008	2009
Cash distributions paid by Partners prior to the simplification	$236,144	$267,184	$213,045
Less distributions paid by Partners to Partners GP	(70,278)	(85,642)	(70,434)
Distributions paid to non-controlling owners' interests	165,866	181,542	142,611
Cash distributions paid by Holdings prior to the simplification	67,261	82,768	67,470
Cash distributions we paid after the simplification	—	—	75,677
Total distributions	$233,127	$264,310	$285,758

23. Owners' Equity

The limited partner units outstanding for Holdings on January 1, 2007 were 62,646,551. There was no change in the number of Holdings limited partner units outstanding until September 28, 2009, when the Holdings limited partner units converted to our limited partner units. The Holdings limited partner units converted at a ratio of 0.6325 to 1.0, and as a result, the Holdings unitholders received 39,623,944 of our limited partner units.

The following table details the changes in the number of our limited partner units outstanding from January 1, 2007 through December 31, 2009.

Limited partner units outstanding on January 1, 2007	**66,360,624**
01/07—Settlement of 2004 award grants	184,905
Other[(a)]	768
Limited partner units outstanding on December 31, 2007	**66,546,297**
01/08—Settlement of 2005 award grants	196,856
Other[(a)]	577
Limited partner units outstanding on December 31, 2008	**66,743,730**
01/09—Settlement of 2006 and 2007 award grants	209,320
Other[(a)]	828
A Additional awards issued in September 2009	10,000
MGG units converted to MMP units[(b)]	39,623,944
Limited partner units outstanding on December 31, 2009[(c)]	**106,587,822**

(a) Limited partner units issued to settle the equity-based retainer paid to one of the independent directors of Partners GP.

(b) Pursuant to the simplification (see Note 2—Simplification), all of the outstanding limited partner units of Holdings converted into our limited partner units on September 28, 2009 at the exchange rate of 0.6325 to 1.0.

(c) The weighted average units outstanding reported on the consolidated statements of income were the pre-simplification outstanding limited partner units of Holdings and our post-simplification limited partner units outstanding, adjusted for director-earned phantom units and certain unvested LTIP awards whose performance metrics have been met.

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, all property and cash in excess of that required to discharge all liabilities will be distributed to the partners in proportion to the positive balances in their respective capital accounts. The limited partners' liability is generally limited to their investment.

Other Changes in Owners' Equity

Capital contributions were $5.2 million and $3.7 million during the years ended December 31, 2007 and 2008, respectively, which primarily consisted of payments Holdings received from MGG Midstream Holdings, L.P. which Holdings in turn reimbursed to us for costs incurred under the G&A cost cap agreement.

General Partner Transactions

In December 2008, Holdings acquired its general partner from MGG Midstream Holdings, L.P. Concurrent with that transaction, MGG Midstream Holdings, L.P. distributed all 5.6 million limited partner units it held in Holdings to its equity owners. Holdings did not issue additional limited partner units and it received no proceeds as a result of these transactions. Subsequent to that transaction, Holdings GP was no longer allocated a portion of Holdings' net income.

In September 2009, pursuant to the simplification (see Note 2—Simplification), our general partner became our wholly-owned subsidiary and no longer holds an economic interest in us.

24. Assignment of Supply Agreement

As part of Partners' acquisition of a pipeline system in October 2004, it assumed a third-party supply agreement. Under this agreement, Partners was obligated to supply petroleum products to one of its customers until 2018. At the time of this acquisition, Partners believed that the profits it would receive from the supply agreement were below the fair value of its tariff-based shipments on this pipeline and it established a liability for the expected shortfall. On March 1, 2008, Partners assigned this supply agreement and sold related inventory of $47.6 million to a third party. Further, Partners returned its former customer's cash deposit, which was $16.5 million at the time of the assignment. During first quarter 2008, Partners obtained a full release from the supply customer; therefore, Partners had no future obligation to perform under this supply agreement, even in the event the third-party assignee was unable to perform its obligations under the agreement. As a result, Partners wrote off the unamortized amount of the liability and recognized a gain of $26.5 million in 2008.

25. Subsequent Events

We evaluated subsequent events through February 24, 2010, the date we filed the financial statements in this 2009 Annual Report on Form 10-K with the Securities and Exchange Commission. No recognizable events occurred during the period.

The following non-recognizable events occurred during the period that we evaluated subsequent events.

- On January 22, 2010, we issued 143,527 limited partner units, of which 140,317 were issued to settle the 2007 unit award grants to certain employees that vested on December 31, 2009 and 3,210 were issued to settle the equity-based retainer paid to two of the directors of our general partner.
- On February 12, 2010, our Compensation Committee approved 241,327 unit award grants pursuant to our long-term incentive plan. These award grants have a three-year vesting period that will end on December 31, 2012.
- On February 12, 2010, we paid cash distributions of $0.71 per unit on our outstanding limited partner units to unitholders of record at the close of business on February 2, 2010. The total distributions paid were $75.8 million.

ITEM 9. ***Changes in and Disagreement With Accountants on Accounting and Financial Disclosure***

None.

ITEM 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rule 13a-14(c) of the Securities Exchange Act) was performed as of the end of the period covered by the date of this report. This evaluation was performed under the supervision and with the participation of our management, including our general partner's Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our general partner's Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and practices are effective in providing reasonable assurance that all required disclosures are included in the current report. There have been no changes in our internal control over financial reporting (as defined in Rule 13a – 15(f) of the Securities Exchange Act) during the quarter ending December 31, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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

Management's Report on Internal Control Over Financial Reporting

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

ITEM 9B. ***Other Information***

None.

PART III

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

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

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

ITEM 11. ***Executive Compensation***

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

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

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

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

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

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

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

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

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

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

PART IV

ITEM 15. *Exhibits and Financial Statement Schedules*

(a)1 and (a)2.

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

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

Exhibit No.	Description
Exhibit 2	
*(a)	Agreement Relating to Simplification of Capital Structure dated as of March 3, 2009 by and among Magellan Midstream Partners, L.P., Magellan GP, LLC, Magellan Midstream Holdings, L.P. and Magellan Midstream Holdings GP, LLC (filed as Exhibit 2.1 to Form 8-K filed March 4, 2009).
*(b)	Amendment No. 1 dated as of August 6, 2009 to the Agreement Relating to Simplification of Capital Structure dated as of March 3, 2009 by and among Magellan Midstream Partners, L.P., Magellan GP, LLC, Magellan Midstream Holdings, L.P. and Magellan Midstream Holdings GP, LLC (filed as Exhibit 2.1 to Form 8-K filed August 10, 2009).
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* Each such exhibit has heretofore been filed with the Securities and Exchange Commission as part of the filing indicated and is incorporated herein by reference.

SIGNATURES

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

MAGELLAN MIDSTREAM PARTNERS, L.P.
(Registrant)

By: MAGELLAN GP, LLC, its general partner

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

Date: February 24, 2010

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

Signature	Title	Date
/s/ DON R. WELLENDORF **Don R. Wellendorf**	Chairman of the Board and Principal Executive Officer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 24, 2010
/s/ JOHN D. CHANDLER **John D. Chandler**	Principal Financial and Accounting Officer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 24, 2010
/s/ WALTER R. ARNHEIM **Walter R. Arnheim**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 24, 2010
/s/ ROBERT G. CROYLE **Robert G. Croyle**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 24, 2010
/s/ PATRICK C. EILERS **Patrick C. Eilers**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 24, 2010
/s/ JAMES C. KEMPNER **James C. Kempner**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 24, 2010
/s/ JAMES R. MONTAGUE **James R. Montague**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 24, 2010
/s/ BARRY R. PEARL **Barry R. Pearl**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 24, 2010

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