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, 2008

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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 common units held by non-affiliates computed by reference to the price at which the common units were last sold as of June 30, 2008 was $2,367,188,809.

As of February 25, 2009, there were 66,953,879 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

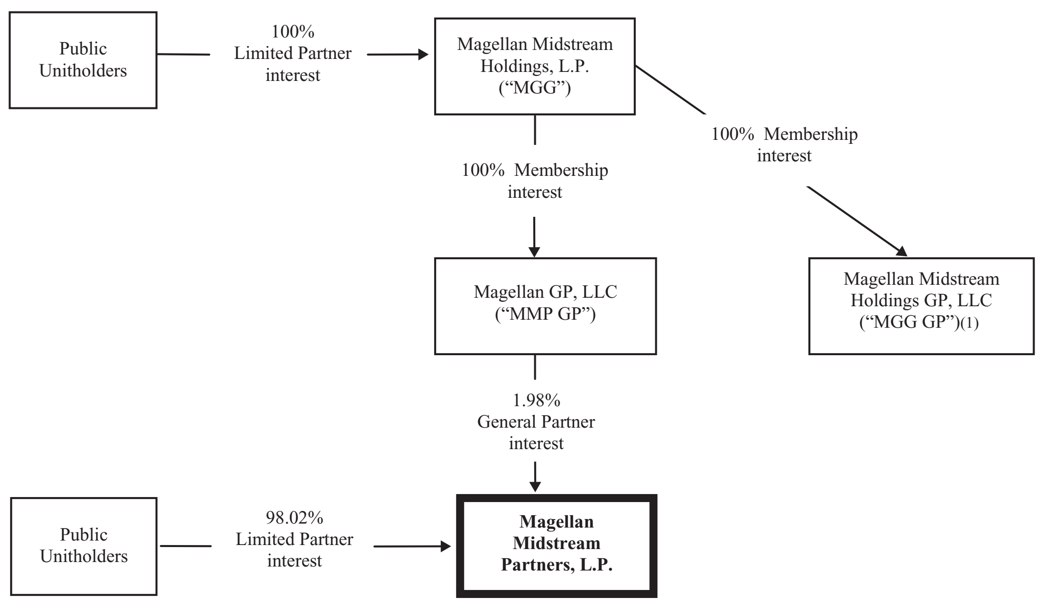
Portions of the registrant's Proxy Statement being prepared for the solicitation of proxies in connection with the 2009 Annual Meeting of Limited Partners are incorporated by reference in Part III of this Form 10-K.

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

ITEM 1. ***Business***

(a) General Development of Business

Unless indicated otherwise, the terms "our," "we," "us" and similar language refer to Magellan Midstream Partners, L.P., together with our subsidiaries. We are a publicly traded Delaware limited partnership. Magellan GP, LLC, a Delaware limited liability company, serves as our general partner and owns an approximate 2% general partner interest in us as well as all of our incentive distribution rights. Magellan GP, LLC is a wholly-owned subsidiary of Magellan Midstream Holdings, L.P., a publicly traded Delaware limited partnership. We and Magellan GP, LLC have contracted with Magellan Midstream Holdings GP, LLC to provide all general and administrative ("G&A") services and operating functions required for our operations. Our organizational structure at December 31, 2008, and that of our affiliate entities, as well as how we refer to these affiliates in this annual report on Form 10-K, are provided below:



(1) MGG GP holds a non-economic general partner interest in MGG.

(b) Financial Information About Segments

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

(c) Narrative Description of Business

We are principally engaged in the transportation, storage and distribution of refined petroleum products. As of December 31, 2008, our asset portfolio consists of:

- an approximately 8,700-mile petroleum products pipeline system, including 49 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
- a 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, distillates 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 2008" published by the Energy Information Administration ("EIA"), the Gulf Coast region accounted for approximately 43% of total U.S. daily refining capacity and 63% of U.S. refining capacity expansion from 1999 to 2007. 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, concentrated refineries.

Description of Our Businesses

PETROLEUM PRODUCTS PIPELINE SYSTEM

Our common carrier petroleum products pipeline system extends approximately 8,700 miles and covers a 13-state area, extending from the Gulf Coast refining region of Texas through the Midwest to Colorado, North Dakota, Minnesota, Wisconsin and Illinois. Our pipeline system transports petroleum products and LPGs and includes 49 terminals. The products transported on our pipeline system are largely transportation fuels, and in 2008 were comprised of 52% gasoline, 39% distillates (which include diesel fuels and heating oil) and 9% aviation fuel and LPGs. Product originates 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 87%, 88% and 84% of our consolidated total revenues for the years ended December 31, 2006, 2007 and 2008, respectively. See Note 14—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 2008 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. The total production of refined petroleum products from refineries located in West North Central districts is currently insufficient to meet the demand for refined petroleum products. The 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 the Explorer and Seaway/ConocoPhillips pipelines. 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,		
	2006	**2007**	**2008**
Shipments (thousand barrels):			
Refined products			
Gasoline	164,548	159,807	152,703
Distillates	113,217	119,602	114,751
Aviation fuel	22,060	24,562	22,190
LPGs	9,812	3,232	6,252
Total product shipments	309,637	307,203	295,896
Capacity leases	21,605	30,114	24,665
Total shipments, including capacity leases	331,242	337,317	320,561
Daily average (thousand barrels)	908	924	876

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. In general, we do not take title to the petroleum products we transport except with respect to our petroleum products blending and fractionation activities and product overages on our pipeline system.

In 2008, our petroleum products pipeline system generated 74% 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 a part of these tariffs are charges for terminalling and storage of products at 37 of our pipeline system's 49 terminals. Revenues from terminalling and storage at our other 12 terminals are at privately negotiated rates.

In 2008, our petroleum products pipeline system generated the remaining 26% 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 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 fees for operating the Longhorn Partners Pipeline and the Osage Pipeline systems.

Product margin for the petroleum products pipeline primarily results from our petroleum products blending and transmix fractionation activities. Our petroleum products blending activity involves purchasing natural gas liquids 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 natural gas liquids. 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. Prior to March 2008, we also received product margin from a third-party supply agreement. Product margin from all of these activities was $50.6 million, $66.2 million and $114.4 million for the years ended December 31, 2006, 2007 and 2008, 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 the first half of 2008.

Facilities. Our petroleum products pipeline system consists of an approximate 8,700-mile pipeline with 49 terminals and includes more than 30.0 million barrels of aggregate usable storage capacity. The terminals deliver petroleum products primarily into tank trucks.

Petroleum Products Supply. Petroleum products originate from both refining and pipeline interconnection points along our pipeline system. In 2008, 60% of the petroleum products transported on our petroleum products pipeline system originated from 12 direct refinery connections and 40% originated from multiple interconnections with other pipelines.

As set forth in the table below, our system is directly connected to, and receives product from, 12 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
Marathon Ashland Petroleum	St. Paul, MN
Murphy Oil USA	Superior, WI
National Cooperative Refining Association	McPherson, KS
Sinclair Oil	Tulsa, OK
Sunoco	Tulsa, OK
Valero Energy	Ardmore, OK
Valero Energy	Houston, TX

Our system is also connected to multiple pipelines, including the pipelines set forth in the table below:

Major Origins—Pipeline Connections (Listed Alphabetically)

Pipeline	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
NuStar Energy	El Dorado, KS; Minneapolis, MN; Wynnewood, OK	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 2008, over 50% 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, 2008, 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, 2008 represented 27% of total revenues for our petroleum products pipeline system and 55% 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 handle refined petroleum products, blendstocks, ethanol, heavy oils, feedstocks, crude oil and condensate. These facilities 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 12%, 11% and 14% of our consolidated total revenues in 2006, 2007 and 2008, respectively. See Note 14—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 U.S. Gulf Coast. Our marine terminals are large storage and distribution facilities, with an aggregate storage capacity of approximately 25.0 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 or spot demand storage services and inventory management 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 and inventory management to various industrial end-users, 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 2008, approximately 96% of our marine terminal capacity was utilized. As of December 31, 2008, over 90% 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. During 2008, we were a party to an agreement pursuant to which we received a discounted storage rate fee and a variable-rate storage fee. The variable-rate storage fee was based on a percentage of the net profits from trading activities conducted by this customer. If our customer's trading profits fell below a specified amount or were negative, our variable-rate storage fee was zero. However, if our customer's trading activities resulted in profit, our variable-rate storage fee was our share of those trading profits above a specified amount.

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 along the Gulf Coast that are currently being used in their refining operations. If these companies chose to shut down their refining operations and elect to store and distribute refined petroleum products through their proprietary terminals, we would experience increased competition for the services we provide. In addition, other companies have facilities in the Gulf Coast region 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 2008, gasoline represented approximately 61% of the product volume distributed through our inland terminals, with the remaining 39% 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 some 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 gasoline, diesel and aviation fuel.

Customers and Contracts. We enter into contracts with customers that typically last for one year with a continuing one-year renewal provision. 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 a 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%, 1% and 2% of our consolidated total revenues for the years ended December 31, 2006, 2007 and 2008. See Note 14—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.

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 six terminals which 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, 2008 through June 30, 2009 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

The percentage of revenue derived from customers that accounted for 10% or more of our consolidated total revenues is provided in the table below. No other customer accounted for more than 10% of our consolidated total revenue for the years ended December 31, 2006, 2007 or 2008. The majority of the revenues from Customers A, B and C resulted from sales to those customers of refined petroleum products that we generated in connection with blending and fractionation activities. In general, accounts receivable from these customers are due within 3 days of sale. Prior to August 2006, Customer E purchased petroleum products from us pursuant to a third-party supply agreement. In August 2006, Customer E assigned its rights under this supply agreement to Customer D. In March 2008, we assigned our obligations under this supply agreement to a third party (see Note 21—Assignment of Supply Agreement).

	2006	2007	2008
Customer A	2%	2%	12%
Customer B	1%	1%	12%
Customer C	11%	13%	8%
Customer D	18%	33%	2%
Customer E	29%	0%	0%
Total	61%	49%	34%

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, extending through June 2011, 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.

Maintenance and Security Regulations

We believe our assets are operated and maintained in material compliance with applicable federal, state and local laws and regulations, and in accordance with other generally accepted industry standards and practices.

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.

The Department of Homeland Security Appropriation Act of 2007 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. Covered facilities that are determined by the DHS to pose a high 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. We have not yet determined what the associated costs will be to comply, but it is possible that such costs could be material.

Environmental & 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.

Estimates provided below 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 as such the total remediation costs may exceed 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 and promptly detect and address releases is an integral part of our operations, damages and liabilities arising out of any future environmental release from our assets have the potential to have a material adverse effect on our results of operations, financial position and cash flow.

Environmental Liabilities. Recorded estimated environmental liabilities were $57.8 million and $41.8 million at December 31, 2007 and 2008, 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.

Petroleum Products EPA Issue. In July 2001, the Environmental Protection Agency ("EPA"), pursuant to Section 308 of the Clean Water Act (the "Act"), served an information request to a former affiliate with regard to petroleum discharges from its pipeline operations. That inquiry primarily focused on the petroleum products pipeline system that we subsequently acquired. The EPA added to their original demand two subsequent releases that occurred from our petroleum products pipeline system. In September 2008, we paid a penalty of $5.3 million and agreed to perform certain operational enhancements under the terms of a settlement agreement reached with the EPA and Department of Justice ("DOJ"). This agreement led to a reduction of our environmental liability for these matters from $17.4 million to $5.3 million and a reduction of our operating expenses of $12.1 million during second quarter 2008.

Ammonia EPA Issue. In February 2007, 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 Act with respect to two releases of anhydrous ammonia from the ammonia pipeline owned by us and, at the time of the releases, operated by a third party. The DOJ stated that the maximum statutory penalty for alleged violations of the Act for both releases combined was approximately $13.2 million. The DOJ also alleged that the third-party operator of our ammonia pipeline was liable for penalties pursuant to Section 103 of the Comprehensive Environmental Response, Compensation and Liability Act for failure to report the releases on a timely basis, with the statutory maximum for those penalties as high as $4.2 million for which the third-party operator has requested indemnification. In March 2007, we also received a demand from the third-party operator for defense and indemnification in regards to a DOJ criminal investigation regarding whether certain actions or omissions of the third-party operator constituted violations of federal criminal statutes. The third-party operator has subsequently settled this criminal investigation with the DOJ by paying a $1.0 million fine. We believe that we do not have an obligation to indemnify or defend the third-party operator for the DOJ criminal fine settlement. The DOJ stated in its notice to us that it does not expect us or the third-party operator to pay the penalties at the statutory maximum; however, it may seek injunctive relief if the parties cannot agree on any necessary corrective actions. We have accrued an amount for these matters based on our best estimates that is less than the maximum statutory penalties. We are currently in discussions with the EPA, DOJ and the third-party operator regarding these two releases; however, we are unable to determine what our ultimate liability could be for these matters. Adjustments to our recorded liability, which could occur in the near term, could be material to our results of operations and cash flows.

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, 2008, known liabilities that would have been covered by these indemnifications were estimated to be $25.5 million. Through December 31, 2008, we have spent $59.0 million of the indemnification settlement proceeds for indemnified matters, including $23.1 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.

Environmental Receivables. Receivables from insurance carriers and other entities related to environmental matters were $6.9 million and $4.5 million at December 31, 2007 and December 31, 2008, respectively.

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.

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.

Above Ground Storage Tanks. Many of our above ground storage tanks containing liquid substances are required under federal Spill Prevention, Control and Countermeasure ("SPCC") regulations to have secondary containment systems or alternative precautions to mitigate potential environmental impacts from any leaks or spills from the tanks. We are continuing to evaluate the SPCC regulations for potential deficiencies at our petroleum products terminals; however, we do not expect the costs of necessary corrective actions will be significant.

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 by us. 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 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.

Air Emissions. 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.

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 lands 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

MGG's general partner, MGG GP, employs various personnel who are assigned to conduct our operational and administrative functions. At December 31, 2008, MGG GP employed 1,204 employees, of whom 577 were assigned to conduct the operations of our petroleum products pipeline system, 296 were assigned to conduct the operations of our petroleum products terminals, 19 were assigned to conduct the operations of our ammonia pipeline system and 312 were assigned to provide G&A services.

At December 31, 2008, the labor force of 577 employees assigned to our petroleum products pipeline system was concentrated in the central United States. Approximately 37% of these employees were represented by the United Steel Workers Union ("USW"). MGG GP's collective bargaining agreement with the USW was ratified by the union members in February 2009. This agreement expires January 31, 2012. The labor force of 296 employees assigned to our petroleum products terminals operations at December 31, 2008 is primarily concentrated in the southeastern and Gulf Coast regions of the United States. Approximately 10% of these employees were represented by the International Union of Operating Engineers and covered by a collective bargaining agreement that expires in October 2010. On June 1, 2008, we assumed operations of our ammonia pipeline from a third-party pipeline company. At December 31, 2008, 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 site 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.

You can also obtain information about us at the New York Stock Exchange's ("NYSE") internet site (www.nyse.com). The NYSE requires the chief executive officer of each listed company to certify annually that he is not aware of any violation by the company of the NYSE corporate governance listing standards as of the date of the certification, qualifying the certification to the extent necessary. The chief executive officer of our general partner submitted an unqualified annual written certification to the NYSE in 2008.

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, 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, including payments to our affiliates.

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.

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. Factors that could lead to a decrease in market demand include:

- an increase in the market price of petroleum products, which may reduce demand for gasoline and other petroleum products. Market prices for petroleum products are subject to wide fluctuation in response to changes in global and regional supply over which we have no control;
- a recession or other adverse economic condition that results in lower spending by consumers and businesses on transportation fuels such as gasoline, aviation fuel and diesel;
- 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 biofuels such as ethanol and biodiesel used in transportation fuels over the next 15 years. Such 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 weather-related or other natural causes, ruptures, leaks and fires. 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 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. 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.

We sometimes negotiate agreements with a customer pursuant to which we charge storage rental and throughput fees based on discounted rates plus a variable fee based on a percentage of the net profits from certain trading activities conducted by our customer. We recognize revenues for the variable fees from these agreements at the end of the contract terms. During 2006, 2007 and 2008, we recognized revenues from variable-rate fee agreements of $9.4 million, $2.8 million and $0.9 million, respectively. We may negotiate similar agreements in the future. Our customer's trading activities, upon which our variable-rate fees are based, involve substantial risks. As a result, our share of the variable-rate revenues from such agreements in future periods could be zero.

We hedge prices of refined products by utilizing physical purchase and sale agreements, futures contracts traded on the New York Mercantile Exchange ("NYMEX") or Intercontinental Exchange ("ICE"), 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.

We hedge our exposure to price fluctuations with respect to refined products generated from or used in our operations by utilizing physical purchase and sale agreements, futures contracts traded on the NYMEX or ICE, options contracts or over-the-counter transactions. To the extent these hedges do not qualify for hedge accounting treatment under Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities (as amended)* 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 make distributions to our unitholders.

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. Weak economic conditions and widespread financial stress could reduce the liquidity of our customers, vendors or counterparties, making it more difficult for them to meet their obligations to us. Any substantial increase in the nonpayment and nonperformance by our customers, vendors or counterparties could have a material adverse effect on our results of operations and cash flows.

We may not be able to obtain funding at acceptable terms because of the deterioration of the credit and capital markets. This may prevent us from meeting our future capital needs.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile, which has caused a substantial deterioration in the credit and capital markets. These conditions, along with significant write-offs in the financial services sector and the re-pricing of credit risk, could make it difficult to obtain funding for our capital needs.

In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. In addition, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to existing debt, and reduced and, in some cases, ceased to provide funding to borrowers.

If any of our 18 committed lenders under our revolving credit facility were to become unwilling or unable to meet their funding obligations, and if the other committed lenders thereunder were to refuse to provide additional funding to make up the portion of the unfulfilled commitments, we would be unable to use the full borrowing capacity under our revolving credit agreement.

Due to these factors, we cannot be certain that funding for our capital needs from credit and capital markets will be available if needed and, to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due or be required to substantially reduce our capital expenditures and therefore be unable to expand our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations.

Losses sustained by any money market mutual fund or other investment vehicle in which we invest our cash or the failure of any bank 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 can 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. A failure of our commercial bank could result in our losing such deposits. 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 such 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 interstate markets. The indexing method allows a pipeline to increase its rates to the new ceiling level by a percentage equal to the change in the PPI-FG plus 1.3%. If the PPI-FG falls, we could 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 is expected to remain in place through June 30, 2011.

Rate increases made pursuant to the indexing methodology can be challenged by protest and/or complaint. The potential for a challenge to our indexed rates creates the risk that the FERC might find some of our indexed rates to be in excess of a just and reasonable level—that is, a level justified by our cost of service. In such an event, the FERC would order us to reduce any such rates and could require the payment of refunds and/or reparations.

We establish rates in approximately 60% of our interstate 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, change in the treatment of income tax allowances or payment of reparations could have a material adverse effect on our results of operations and reduce the amount of cash we generate.

The FERC's policies regarding income tax allowance and return on equity in cost-of-service based rates could affect the amount of cash we generate.

In May 2005, the FERC adopted a policy statement ("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 the 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.

In December 2006, the FERC issued an order addressing income tax allowance in rates, in which it reaffirmed prior statements regarding its income tax allowance policy, but raised a new issue regarding the implications of the Policy Statement for publicly traded partnerships. The FERC noted that the tax deferral features of a publicly traded partnership may cause some investors to receive, for some indeterminate duration, cash distributions in excess of their taxable income, creating an opportunity for those investors to earn additional return, funded by ratepayers. Responding to this concern, FERC adjusted the equity rate of return of the pipeline at issue downward based on the percentage by which the publicly traded partnership's cash flow exceeded taxable income. Requests for rehearing of the order are currently pending before the FERC.

Whether a pipeline's owners have actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the FERC's current income tax allowance policy is generally favorable for pipelines that are organized as pass-through entities, it still entails rate risks due to the case-by-case review requirement. How the Policy Statement is applied in practice to pipelines owned by publicly traded partnerships could impose limits on our ability to include a full income tax allowance in cost of service.

The FERC instituted a rulemaking proceeding in July 2007 to determine whether any changes should be made to the FERC's methodology for determining natural gas and oil pipeline equity returns to be included in cost-of-service based rates. The FERC determined that it would retain its current methodology for determining return on equity but that, when stock prices and cash distributions of tax pass-through entities are used in the return on equity calculations, the growth forecasts for those entities should be reduced by 50%. Despite the FERC's determination, some complainants in rate proceedings have advocated that the FERC disallow the full use of cash distributions in the return on equity calculation. If the FERC were to disallow the use of full cash distributions in the return on equity calculation, such a result might adversely affect our ability to achieve a reasonable return.

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 price levels 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 interstate markets served by our petroleum products pipeline system. The indexing method allows a pipeline to increase 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.

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

We face competition from other pipelines and terminals in the same markets as our assets. Our customers demand delivery of products on tight time schedules and in a number of geographic markets. If our quality of service declines or we cannot meet the demands of our customers, they may utilize the services of our competitors.

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

Our operations may incur substantial liabilities to comply with climate change legislation and regulatory initiatives.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. 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. As an alternative to reducing emission of greenhouse gases under cap and trade programs, Congress may consider the implementation of a program to tax the emission of carbon dioxide and other greenhouse gases. The EPA is separately considering whether it will regulate greenhouse gases as "air pollutants" under the existing federal Clean Air Act. Passage of climate change legislation or other regulatory initiatives by Congress or various states of the U.S. or the adoption of regulations by the EPA or analogous state agencies that regulate or restrict emissions of greenhouse gases in areas in which we conduct business could result in changes to the demand for the products we store, transport and distribute, and could increase the costs of our operations, including costs to operate and maintain our facilities, 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 recover any such lost revenues or increased costs in the rates we charge our customers, and any such recovery may depend on events beyond our control, including the outcome of future rate proceedings before the FERC and the provisions of any final legislation or regulations. Reductions in our revenues or increases in our expenses as a result of climate control initiatives could have adverse effects on our business, financial position, results of operations and prospects.

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 the amount of cash we generate.

The EPA has adopted requirements that require refineries to install equipment to lower the sulfur content of gasoline and some diesel fuel they produce. The requirements relating to gasoline took effect in 2004, and the requirements relating to diesel fuel are being implemented through 2010. If refinery owners that use our petroleum pipeline system determine that compliance with these new requirements is too costly, they may close some of these refineries. In addition, the downturn in the U.S. and global economy has resulted in lower demand for refined petroleum products and has placed additional pressures on the profitability of refiners. A period of sustained weak demand and low profit margins may 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.

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 reduce 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.

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 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 and transport.

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 could reduce or eliminate our ability to blend products.

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 United States 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.

Rising short-term interest rates could increase our financing costs and reduce the amount of cash we generate.

As of December 31, 2008, we had $70.0 million of floating rate borrowings outstanding on our revolving credit facility. We intend to use the floating rate facility to facilitate expansion capital spending in 2009. As a result, we have exposure to changes in short-term interest rates. Rising short-term rates could reduce the amount of cash we generate and adversely affect 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. In addition, a change in control of our general partner could, under certain circumstances, result in our debt becoming due and payable.

Our financial reporting is subject to rules promulgated primarily by the Financial Accounting Standards Board ("FASB") and the SEC. Changes in these rules could result in our incurring increased costs, as well as in material changes to our financial statements and related disclosures.

Rule changes promulgated by the FASB or SEC could result in significant changes to our current financial reporting policies and procedures. For example, the SEC's proposed rule under Release No. 33-9005, *Roadmap* *for the Potential Use of Financial Statements Prepared in Accordance With International Financial Reporting Standards by U.S. Issuers* could result in our being required to file financial statements that conform to international financial accounting standards rather than U.S. generally accepted accounting standards. The costs to convert to international standards could be material and could result in material changes to our reported financial position, results of operations and cash flows. Similarly, in Emerging Issue Task Force ("EITF") Issue No. 04-7, *Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships*, FASB required a change in the methodology by which we allocate income between our general and limited partners. We adopted this EITF on January 1, 2009. Had this EITF been in effect for 2008, our reported basic and diluted earnings per unit would have increased by $0.49, or 15%. Material changes in our reported earnings per unit could influence our unit price.

Risks Related to Our Partnership Structure

Cost reimbursements due our general partner may be substantial and could reduce our cash available for distribution.

Prior to making any distribution on our limited partner units, we reimburse our general partner and its affiliates, including officers and directors of our general partner, for expenses they incur on our behalf. These reimbursements could adversely affect our ability to pay cash distributions. Our general partner has sole discretion to determine the amount of its expenses which must be reimbursed. In addition, our general partner and its affiliates may provide us other services for which we will be charged fees as determined by our general partner.

Our general partner's absolute discretion in determining the 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.

Potential conflicts of interest may arise among our general partner, its affiliates and us. Our general partner and its affiliates have limited fiduciary duties to us and our unitholders, which may permit them to favor their own interests to the detriment of us and our unitholders.

Conflicts of interest may arise among our general partner and it affiliates, including MGG, on the one hand, and us and our unitholders, on the other hand. The directors and officers of our general partner have fiduciary duties to manage us in a manner beneficial to us and our limited partners. At the same time, our general partner has a fiduciary duty to manage us in a manner beneficial to MGG, the owner of our general partner, and its affiliates. The board of directors of our general partner will resolve any such conflict and has broad latitude to consider the interests of all parties to the conflict. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders.

These conflicts may include, among others, the following:

- our general partner is allowed to take into account the interests of parties other than us, including MGG, and their respective affiliates, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;
- our general partner determines whether or not we incur debt and that decision may affect our credit ratings;

- our general partner has limited its liability and reduced its fiduciary duties under the partnership agreement, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty;
- our general partner determines the amount and timing of our investment transactions, borrowings, issuances of additional partnership securities and reserves, each of which can affect the amount of cash that is available for distribution to our unitholders;
- our general partner, through its ownership of our incentive distribution rights, is entitled to receive increasing percentages, up to a maximum of 48%, of any incremental cash we distribute per limited partner unit, which could reduce our ability to complete accretive transactions or otherwise increase the amount of cash available for distribution to our unitholders;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered, or from entering into additional contractual arrangements with any of these entities on our behalf, so long as the terms of any such additional contractual arrangements are fair and reasonable to us;
- our general partner controls the enforcement of obligations owed to us by it and its affiliates;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us;
- our general partner determines the allocation of shared overhead expenses to MGG and us; and
- our general partner interprets and enforces contractual obligations between us and our affiliates, on the one hand, and MGG, on the other hand.

All of our executive officers face conflicts in the allocation of their time to our business.

Our general partner shares officers and administrative personnel with MGG's general partner to operate both our business and MGG's business. Our general partner's officers, several of whom are also officers of MGG's general partner, will allocate the time they and the other employees of MGG's general partner spend on our behalf and on behalf of MGG. These officers face conflicts regarding the allocation of their and other employees' time, which may adversely affect our results of operations, cash flows and financial condition. These allocations may not necessarily be the result of arms-length negotiations between our general partner and MGG's general partner.

Changes in the composition of our board of directors could impact our business strategies.

We are a limited partnership and do not have our own board of directors. We are managed and operated by the officers of, and are subject to the oversight of the board of directors of, our general partner. The total number of directors on our general partner's board of directors is currently set at eight and there are four vacancies. When these vacancies are filled, the composition of our general partner's board of directors will change, resulting in new directors that may not continue with previous business strategies.

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", in place. 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 units over current prices. MGG also has a unit purchase rights plan.

Tax Risks to Common 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 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. Although we do not believe based upon our current operations that we are so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purpose 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.

Current law may change causing us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits and 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, we are required to pay Texas franchise tax at a rate of 1% of our net revenue apportioned to Texas in the prior year. Imposition of such a tax on us by Texas and, if applicable, any other state will reduce the cash available for distribution to our unitholders.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal income tax purposes, the target distribution amounts will be adjusted to reflect the impact of that law on us.

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

The federal income tax treatment of common unitholders depends in some instances on determinations of fact and interpretations of complex provisions of federal income tax law. The federal income tax rules are constantly under review by persons involved in the legislative process, the IRS and the U.S. Treasury Department, frequently resulting in revised interpretations of established concepts, statutory changes, revisions to Treasury regulations and other modifications and interpretations. The IRS pays close attention to the proper application of tax laws to partnerships. The present federal income tax treatment of an investment in our limited partner units may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for federal income tax purposes that is not taxable as a corporation (referred to as the "Qualifying Income

Exception”), affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our common units. For example, in response to recent public offerings of interests in the management operations of private equity funds and hedge funds, members of Congress have considered substantive changes to the definition of qualifying income under Section 7704 of the Internal Revenue Code which could change the characterization of certain types of income received from partnerships. Although the legislation would not have applied to us as currently proposed, we are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our limited partner units and the amount of cash available to pay as distributions to our unitholders.

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 our counsel’s conclusions or 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 ordinary income. In addition, if our unitholders sell their 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 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 United States 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 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 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 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. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those 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 units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those 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 units.

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

When we issue additional 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 limited partners and general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our general partner and limited 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 common units and could have a negative impact on the value of the common 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 will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one fiscal year and could result 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 may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

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 do business or own property, 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 United States 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 DOJ that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Sections 301 and 311 of the Act with respect to two releases of anhydrous ammonia from the ammonia pipeline owned by us and, at the time of the releases, operated by a third party. The DOJ stated that the maximum statutory penalty for alleged violations of the Act for both releases combined was approximately $13.2 million. The DOJ also alleged that the third-party operator of our ammonia pipeline was liable for penalties pursuant to Section 103 of the Comprehensive Environmental Response, Compensation and Liability Act for failure to report the releases on a timely basis, with the statutory maximum for those penalties as high as $4.2 million, for which the third-party operator has requested indemnification. In March 2007, we also received a demand from the third-party operator for defense and indemnification in regards to a DOJ criminal investigation regarding whether certain actions or omissions of the third-party operator constituted violations of federal criminal statutes. The third-party operator has subsequently settled this criminal investigation with the DOJ by paying a $1.0 million fine. We believe that we do not have an obligation to indemnify or defend the third-party operator for the DOJ criminal fine settlement. The DOJ stated in its notice to us that it does not expect us or the third-party operator to pay the penalties at the statutory maximum; however, it may seek injunctive relief if the parties cannot agree on any necessary corrective actions. We have accrued an amount for these matters based on our best estimates that is less than the maximum statutory penalties. We are currently in discussions with the EPA, DOJ and the third-party operator regarding these two releases; however, we are unable to determine what our ultimate liability could be for these matters. Adjustments to our recorded liability, which could occur in the near term, could be material to our results of operations and cash flows.

In June 2008, we received a Notice of Probable Violation ("NOPV") from the Department of Transportation, Pipeline and Hazardous Materials Safety Administration ("DOT PHMSA") with a preliminary assessed civil penalty of $0.8 million for alleged violations associated with a May 2005 pipeline release that occurred in the Fairfax Industrial District of Kansas City, Kansas. The violations principally involve allegations of failing to follow our system integrity plan. We submitted a request on a timely basis for hearing and anticipate that it will be held during the first quarter of 2009.

In May 2006, we received a NOPV from the DOT PHMSA alleging two areas of non-compliance with 40 CFR 452 (Pipeline Integrity Management in High Consequence Areas); specifically that (1) adequate technical justification was not presented for our formula in calculating the spill volume of refined product for an overall spread analysis and (2) the baseline assessment plan was not established by risk priority. DOT PHMSA has preliminarily assessed a civil penalty of $0.2 million for both allegations. A hearing was held in September 2006. We submitted our post-hearing brief in October 2006. In February 2007, we responded to a series of questions from the hearing officer. No further response from DOT PHMSA has been received to date.

In April 2005, we received a NOPV from the Office of Pipeline Safety ("OPS") as a result of an inspection of our operator qualification records and procedures. The NOPV alleges that probable violations of 49 CFR Part 195.505 occurred in regards to our operator qualification program. The OPS has preliminarily assessed a civil penalty of $0.2 million. We have submitted a response to the NOPV, participated in a hearing at our request with the OPS and submitted a post-hearing brief. No further response from the OPS has been received to date.

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 Common 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 20, 2009, we had 227 registered holders and approximately 58,200 beneficial holders of record of our limited partner units. The year-end closing sales price of our limited partner units was $43.36 on December 31, 2007 and $30.21 on December 31, 2008. The high and low trading sales price ranges for and distributions paid on our limited partner units by quarter for 2007 and 2008 are as follows:

	2007			2008		
Quarter	High	Low	Distribution*	High	Low	Distribution*
1st	$47.94	$37.80	$0.61625	$45.00	$38.34	$0.67250
2nd	$53.39	$43.21	$0.63000	$43.61	$35.47	$0.68750
3rd	$48.00	$38.50	$0.64375	$38.06	$29.51	$0.70250
4th	$43.99	$39.51	$0.65750	$37.32	$18.85	$0.71000

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

Through ownership of our incentive distribution rights, our general partner is entitled to receive increasing percentages of incremental cash we distribute in excess of specified target distribution levels. In addition, our general partner receives distributions on its approximate 2% interest in us.

On January 24, 2008, we issued 197,433 limited partner units primarily to settle award grants under our equity-based incentive compensation plan that vested on December 31, 2007. On January 23, 2009, we issued 210,149 limited partner units primarily to settle award grants under our equity-based incentive compensation plan that vested on December 31, 2008. Our general partner did not make an equity contribution associated with these equity issuances and, as a result, cash distributions paid after January 23, 2009 will be made as follows:

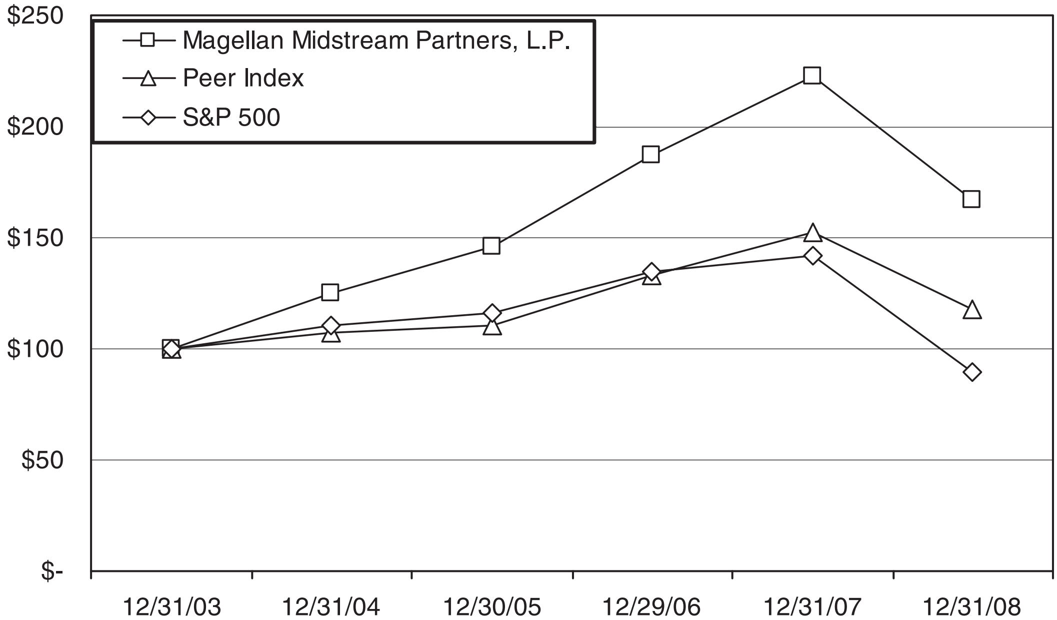
	Percentage of Distributions		
		General Partner	
Quarterly Distribution Amount per Unit	Limited Partners	General Partner Interest	Incentive Distribution Rights
Up to $0.289	98.017%	1.983%	0.000%
Above $0.289 up to $0.328	85.017%	1.983%	13.000%
Above $0.328 up to $0.394	75.017%	1.983%	23.000%
Above $0.394	50.017%	1.983%	48.000%

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, which entitles our general partner to receive approximately 33% of the total cash distributions paid.

Unitholder Return Performance Presentation

The following graph compares the performance of our limited partner units with the performance of the Standard & Poor's 500 Stock Index ("S&P 500") and a peer group index for the period commencing on December 31, 2003. The graph assumes that $100 was invested at the beginning of the period in each of (1) our limited partner units, (2) the S&P 500 and (3) the peer group, and that all distributions or dividends are reinvested on a quarterly basis.

We do not believe that any published industry or line-of-business index accurately reflects our business. Accordingly, we have created a special peer index consisting of the following growth-oriented publicly traded partnerships: 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).



	12/31/03	12/31/04	12/30/05	12/29/06	12/31/07	12/31/08
Magellan Midstream Partners, L.P.	100.0	125.3	146.3	187.2	222.5	166.9
Peer Index	100.0	107.0	110.3	132.7	152.3	117.6
S&P 500	100.0	110.8	116.3	134.6	142.0	89.5

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*

We have derived the summary selected historical financial data from our current and historical audited consolidated financial statements and related notes. Information concerning significant trends in our financial condition and results of operations is contained in Item 7 *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

Our operating results incorporate a number of significant estimates and uncertainties. Such matters could cause the data included herein not to be indicative of our future financial conditions or results of operations. A discussion of our 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 2—*Summary of Significant Accounting Policies* under Item 8 *Financial Statements and Supplementary Data* of this report provides descriptions of areas where estimates and judgments could result in different amounts recognized in our accompanying consolidated financial statements.

We define 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. 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 EBITDA excludes some items that affect net income and these items may vary among other companies, the EBITDA data presented may not be comparable to similarly titled measures of other companies. Our management uses 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 EBITDA to net income, the nearest comparable GAAP measure, is included in the following schedules.

In addition to EBITDA, the non-GAAP measure of operating margin (in the aggregate and by segment) is presented in the following tables. We compute the components of operating margin 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 following tables (see Note 14—Segment Disclosures in the accompanying consolidated financial statements for a reconciliation of segment operating margin to segment operating profit). We believe that investors benefit from having access to the same financial measures being utilized by management. Operating margin is an important measure of the economic performance of our core operations. This measure forms the basis of our internal financial reporting and is used by our management in deciding how to allocate capital resources between segments. Operating profit, alternatively, includes expense items, such as depreciation and amortization and affiliate general and administrative ("G&A") expense, which management does not consider when evaluating the core profitability of an operation.

	Year Ended December 31,				
	2004	2005	2006	2007	2008
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenues	$ 419,117	$ 500,196	$ 558,301	$ 607,845	$ 637,958
Product sales revenues	275,769	636,209	664,569	709,564	574,095
Affiliate management fee revenues	488	667	690	712	733
Total revenues	695,374	1,137,072	1,223,560	1,318,121	1,212,786
Operating expenses	179,657	229,795	244,526	251,601	265,728
Product purchases	255,599	582,631	605,341	633,909	436,567
Gain on assignment of supply agreement	—	—	—	—	(26,492)
Equity earnings	(1,602)	(3,104)	(3,324)	(4,027)	(4,067)
Operating margin	261,720	327,750	377,017	436,638	541,050
Depreciation and amortization expense	41,845	56,307	60,852	63,792	71,153
Affiliate G&A expense	54,466	61,131	67,112	72,587	70,435
Operating profit	165,409	210,312	249,053	300,259	399,462
Interest expense, net	35,435	48,258	53,010	51,045	50,470
Debt prepayment premium	12,666	—	—	1,984	—
Write-off of unamortized debt placement fees	5,002	—	—	—	—
Debt placement fee amortization	3,056	2,871	2,681	2,144	767
Other (income) expense, net	(953)	(300)	634	728	(375)
Income before provision for income taxes	110,203	159,483	192,728	244,358	348,600
Provision for income taxes[(a)]	—	—	—	1,568	1,987
Net income	$ 110,203	$ 159,483	$ 192,728	$ 242,790	$ 346,613
Basic net income per limited partner unit	$ 1.72	$ 2.04	$ 2.24	$ 2.60	$ 3.28
Diluted net income per limited partner unit	$ 1.72	$ 2.03	$ 2.24	$ 2.60	$ 3.27
Balance Sheet Data:					
Working capital (deficit)[(b)]	$ 71,737	$ (206)	$ (341,371)	$ (15,563)	$ (29,675)
Total assets	1,817,832	1,876,518	1,952,649	2,101,194	2,296,115
Long-term debt[(b)]	789,568	782,639	518,609	914,536	1,083,485
Partners' capital	789,109	807,990	806,482	871,164	955,442
Cash Distribution Data:					
Cash distributions declared per unit[(c)]	$ 1.76	$ 2.06	$ 2.34	$ 2.55	$ 2.77
Cash distributions paid per unit[(c)]	$ 1.72	$ 1.97	$ 2.29	$ 2.49	$ 2.72

	Year Ended December 31,				
	2004	2005	2006	2007	2008
	(in thousands, except operating statistics)				
Other Data:					
Operating margin (loss):					
Petroleum products pipeline system	$195,024	$249,435	$284,190	$351,246	$424,957
Petroleum products terminals	56,339	67,224	86,703	85,368	103,967
Ammonia pipeline system	7,328	7,685	2,541	(3,008)	8,643
Allocated partnership depreciation costs(d)	3,029	3,406	3,583	3,032	3,483
Operating margin	$261,720	$327,750	$377,017	$436,638	$541,050
EBITDA:					
Net income	$110,203	$159,483	$192,728	$242,790	$346,613
Provision for income taxes(a)	—	—	—	1,568	1,987
Debt prepayment premium	12,666	—	—	1,984	—
Write-off of unamortized debt placement fees	5,002	—	—	—	—
Debt placement fee amortization	3,056	2,871	2,681	2,144	767
Interest expense, net	35,435	48,258	53,010	51,045	50,470
Depreciation and amortization expense	41,845	56,307	60,852	63,792	71,153
EBITDA	$208,207	$266,919	$309,271	$363,323	$470,990
Operating statistics:					
Petroleum products pipeline system:					
Transportation revenue per barrel shipped	$ 0.996	$ 1.025	$ 1.060	$ 1.147	$ 1.193
Volume shipped (million barrels)	256.0	298.6	309.6	307.2	295.9
Petroleum products terminals:					
Marine terminal average storage utilized (million barrels per month)(e)	18.4	20.4	20.9	21.8	23.3
Inland terminal throughput (million barrels)	93.6	101.3	110.1	117.3	108.1
Ammonia pipeline system:					
Volume shipped (thousand tons)	765	713	726	716	822

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

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

(c) Cash distributions declared represent distributions declared associated with each calendar year. Distributions were declared and paid within 45 days following the close of each quarter. Cash distributions paid represent cash payments for distributions during each of the periods presented.

(d) Certain 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.

(e) For the year ended December 31, 2004, represents the average monthly storage capacity utilized for the three months we owned the East Houston, Texas facility (1.9 million barrels) and the weighted-average storage capacity utilized for the full year at our other marine terminals (16.5 million barrels). For the year ended December 31, 2005, represents the average storage capacity utilized for the four months we owned our Wilmington, Delaware terminal (1.8 million barrels) and the average monthly storage capacity utilized for the full year at our other marine terminals (18.6 million barrels).

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, 2008, our three operating segments included:

- petroleum products pipeline system, which is primarily comprised of our approximately 8,700-mile petroleum products pipeline system, including 49 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, 2008.

Recent Developments

Recession and deterioration of credit, capital and commodity markets. The U.S. economy contracted significantly during recent quarters, resulting in increases in bankruptcies and unemployment. Credit market conditions also deteriorated rapidly during the same period. Several major banks and financial institutions failed or were forced to seek assistance through distressed sales or emergency government measures.

Declining economic conditions and the impact of hurricanes experienced in the U.S. in the latter half of 2008 contributed to the reduction in through-put we experienced on our refined petroleum products pipeline system during this same period. A prolonged economic downturn in the United States could further decrease demand for the petroleum products we transport, store and distribute, which could in turn result in lower demand for our services and a reduction in our revenues and cash flow. In addition, current economic and capital market conditions in some circumstances have impaired or could impair the financial condition of our customers and suppliers, increasing the probability that we could experience losses from customer or supplier defaults.

The prices of energy commodities have been extremely volatile in recent periods, and have recently fallen rapidly from historic highs. Periods of sustained high prices for the products we transport, store and distribute could result in lower demand for those products and lead to reduced demand for our services, while periods of sustained low prices could have the opposite effect. During periods of low product prices, including the current period, we will generally experience reduced margins from our petroleum products blending and fractionation activities, while during periods of high product prices we will generally experience higher margins from those activities. We are unable to predict product prices and how they will impact our financial position, results of operation or cash flow.

Cash generated from operations is our primary source of liquidity for funding debt service, maintenance capital expenditures and quarterly distributions. However, we rely on our revolving credit facility to provide additional liquidity for working capital needs and as an interim source of financing for expansion capital projects. Our revolving credit facility has total committed capacity of $550.0 million, and drawings on that facility at December 31, 2008 were $70.0 million, with an additional $3.9 million obligated for letters of credit. The facility is funded by a syndicate of 18 banks. To date, all of the banks in the syndicate have continued to meet their commitments despite the recent market turmoil. If any banks in the syndicate were unable to perform on their commitments to fund the facility, our liquidity could be impaired, which could reduce our ability to fund growth capital expenditures or finance our working capital needs.

Current market conditions have also resulted in higher credit spreads on long-term borrowings and significantly reduced demand for new corporate debt issues. Equity prices, including our own unit price, have experienced abnormally high volatility over recent months. If these conditions persist, our cost of capital could increase and our ability to finance growth capital expenditures or acquisitions in a cost-effective manner could be reduced.

We rely on insurers as protection against liability claims, property damage, environmental damage and various other risks. Our primary insurers maintain an A.M. Best financial strength rating of A or better, which is considered excellent or superior, and have adjusted policyholder surplus of $1.0 billion or higher. Nevertheless, we continue to monitor this situation as insurers have been and are expected to continue to be impacted by the current credit and capital market environment.

Commodity derivative agreements. Prior to July 2008, we sold refined petroleum products, primarily from our petroleum products blending activities, to customers through forward sales contracts. Since our customers took physical delivery of these products the associated forward sales agreements qualified for normal sales accounting treatment. Because of changes in the liquidity of these markets in mid-2008, we generally have been unable to execute similar agreements on acceptable terms since that time. As a result, in August 2008, we began entering into New York Mercantile Exchange ("NYMEX") commodity-based futures sales contracts to hedge our exposure to price fluctuations. Although these NYMEX agreements represent an economic hedge against price changes for petroleum products we expect to sell in the future, they do not meet the requirements for hedge accounting treatment. As a result, we are recognizing the change in fair value of these agreements currently in earnings, which could result in material gains or losses in our results of operations. For the year ended December 31, 2008, we recorded product sales for unrealized gains of $20.2 million on our open NYMEX positions. These open NYMEX agreements had maturities between January 2009 and April 2009.

We expect to continue to enter into NYMEX agreements to hedge against price changes for additional volumes of petroleum products related to our blending activities and for other commodity hedging activities. To the extent we use NYMEX contracts, we could experience additional risks related to price basis differentials and margin calls. The change in fair value of these NYMEX agreements could result in material impacts to our results of operations and cash flows in future periods.

Distribution. During January 2009, 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, 2008. As a result, total distributions related to 2008 were $2.77 per unit compared to $2.55 per unit related to 2007, an increase of 9%. The $0.71 per unit distribution was paid on February 13, 2009 to unitholders of record on February 6, 2009.

Overview

Our petroleum products pipeline system and petroleum products terminals generate substantially all of our cash flows 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. 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. For a discussion of indemnified environmental matters, see *General Business Information—Environmental & Safety* under Item 1 of this Annual Report on Form 10-K.

A prolonged period of high refined petroleum product prices or 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 and liquefied petroleum gases 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 2008, the pipeline generated 74% 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 unloading and loading, additive injection, custom blending and laboratory testing.

In general, we do not take title to the products that we transport. However, 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. Although our petroleum products blending and fractionation activities 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. A third-party pipeline company operated our ammonia pipeline system until we assumed operating responsibility of this pipeline system on July 1, 2008.

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. Industry themes continue to drive our current expansion projects, including:

- 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 are currently assessing the feasibility of a dedicated ethanol pipeline; and
- refinery expansions and enhanced connectivity to key growth markets such as Denver, Colorado and 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.

We spent $266.2 million on growth projects during 2008 and $150.5 million in 2007. Further, we expect to spend approximately $215.0 million in 2009 on projects that are currently underway, with additional spending of approximately $30.0 million expected in 2010 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 being utilized by management. Operating margin, which is presented in the tables below, is an important measure used by management to evaluate the economic performance of our core operations. This measure forms the basis of our internal financial reporting and is used by management in deciding how to allocate capital resources between segments. 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 tables below. Operating profit includes expense items, such as depreciation and amortization expense and affiliate 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 petroleum products blending and fractionation activities, is provided in the tables below. 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, 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	$459.8	$477.6	$ 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	(3.0)	(3.4)	(0.4)	(13)
Total transportation and terminals revenues	607.8	638.0	30.2	5
Affiliate management fee revenues	0.7	0.7	—	—
Operating expenses:				
Petroleum products pipeline system	179.4	198.4	(19.0)	(11)
Petroleum products terminals	56.3	59.3	(3.0)	(5)
Ammonia pipeline system	21.3	14.1	7.2	34
Intersegment eliminations	(5.4)	(6.1)	0.7	13
Total operating expenses	251.6	265.7	(14.1)	(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	436.6	541.1	104.5	24
Depreciation and amortization expense	63.7	71.2	(7.5)	(12)
Affiliate G&A expense	72.6	70.4	2.2	3
Operating profit	300.3	399.5	99.2	33
Interest expense (net of interest income and interest capitalized)	51.0	50.5	0.5	1
Debt placement fee amortization	2.1	0.8	1.3	62
Debt prepayment premium	2.0	—	2.0	100
Other (income) expense	0.8	(0.4)	1.2	150
Income before provision for income taxes	244.4	348.6	104.2	43
Provision for income taxes	1.6	2.0	(0.4)	(25)
Net income	$242.8	$346.6	$ 103.8	43
Operating Statistics				
Petroleum products pipeline system:				
Transportation revenue per barrel shipped	$1.147	$1.193		
Volume shipped (million barrels)	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		

Transportation and terminals revenues increased by $30.2 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 third and fourth quarter 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, including lower revenue recognized from our variable-rate storage agreement. 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 $14.1 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 $19.0 million primarily due to less favorable product overages (which reduce operating expenses) in the current period, higher system integrity spending and increased environmental accruals for several historical releases. The higher system integrity spending was due to accelerating work into the current year that was originally planned to occur in 2009. Partially offsetting these items was a $12.1 million reduction to our operating expenses in second quarter 2008 due to the favorable settlement of a civil penalty related to historical product releases;
- an increase in petroleum products terminals expenses of $3.0 million primarily related to higher personnel costs and maintenance spending, including clean-up costs related to Hurricane Ike. 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. We expect system integrity costs to be significantly higher in 2009 due to additional integrity work identified in 2008.

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 gross margin we realize on these activities can be substantially higher in periods when refined petroleum prices increase and substantially lower in periods when product prices decline or stabilize given that we follow an average inventory valuation methodology which results in each period's product purchases being influenced by the value of products held in that period's beginning inventory. Given the current pricing environment for petroleum products, we expect our product margin for 2009 to be substantially lower than 2008.

The 2008 period benefited from a $26.5 million gain on the assignment of a 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.

Operating margin increased $104.5 million primarily due to higher gross margin from product sales in 2008 and higher revenues from each of our business segments.

Depreciation and amortization expense increased by $7.5 million primarily due to capital expansion projects placed into service over the past year.

Affiliate G&A expense decreased by $2.2 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 an affiliate of our general partner to one of our executive officers. The lower equity-based incentive compensation expenses resulted from a lower weighted-average fair value for units awarded to plan participants and reduced 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. Magellan Midstream Holdings, L.P. ("MGG"), the owner of our general partner, historically reimbursed us for our actual G&A costs that exceeded certain amounts as described in our omnibus agreement. The amount of G&A costs reimbursed to us for the years ended December 31, 2007 and 2008 was $4.1 million and $1.6 million, respectively. We will not receive any reimbursements from MGG for G&A costs in future periods.

Interest expense, net of interest income and interest capitalized, decreased $0.5 million. 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 6.4% 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 $1.3 million in 2008 due to the 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.

Provision for income taxes increased $0.4 million in 2008 due primarily to a change in our partnership-level tax rate from 0.5% in 2007 to 1.0% in 2008. This rate increase resulted from our losing our petroleum product wholesaler status with the state of Texas following our assignment of a supply agreement in March 2008.

Year Ended December 31, 2006 Compared to Year Ended December 31, 2007

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2006	2007	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum products pipeline system	$419.3	$459.8	$ 40.5	10
Petroleum products terminals	125.9	132.7	6.8	5
Ammonia pipeline system	16.5	18.3	1.8	11
Intersegment eliminations	(3.4)	(3.0)	0.4	12
Total transportation and terminals revenues	558.3	607.8	49.5	9
Affiliate management fee revenues	0.7	0.7	—	—
Operating expenses:				
Petroleum products pipeline system	189.7	179.4	10.3	5
Petroleum products terminals	47.3	56.3	(9.0)	(19)
Ammonia pipeline system	13.9	21.3	(7.4)	(53)
Intersegment eliminations	(6.4)	(5.4)	(1.0)	(16)
Total operating expenses	244.5	251.6	(7.1)	(3)
Product margin:				
Product sales	664.6	709.6	45.0	7
Product purchases	605.3	633.9	(28.6)	(5)
Product margin	59.3	75.7	16.4	28
Equity earnings	3.3	4.0	0.7	21
Operating margin	377.1	436.6	59.5	16
Depreciation and amortization expense	60.9	63.7	(2.8)	(5)
Affiliate G&A expense	67.1	72.6	(5.5)	(8)
Operating profit	249.1	300.3	51.2	21
Interest expense (net of interest income and interest capitalized)	53.0	51.0	2.0	4
Debt placement fee amortization	2.7	2.1	0.6	22
Debt prepayment premium	—	2.0	(2.0)	N/A
Other expense	0.7	0.8	(0.1)	(14)
Income before provision for income taxes	192.7	244.4	51.7	27
Provision for income taxes	—	1.6	(1.6)	N/A
Net income	$192.7	$242.8	$ 50.1	26
Operating Statistics				
Petroleum products pipeline system:				
Transportation revenue per barrel shipped	$1.060	$1.147		
Volume shipped (million barrels)	309.6	307.2		
Petroleum products terminals:				
Marine terminal average storage utilized (million barrels per month)	20.9	21.8		
Inland terminal throughput (million barrels)	110.1	117.3		
Ammonia pipeline system:				
Volume shipped (thousand tons)	726	716		

Transportation and terminals revenues increased by $49.5 million resulting from higher revenues for each of our business segments as shown below:

- an increase in petroleum products pipeline system revenues of $40.5 million. Transportation revenues increased as a result of higher average tariffs due in part to our mid-year 2006 and 2007 tariff escalations, partially offset by slightly lower transportation volumes due to various factors which resulted in several refineries connected to our system curtailing production during the 2007 year. We also earned more ancillary revenues related to higher fees for leased storage as well as additional demand for our terminal, additive and renewable fuels services during 2007;
- an increase in petroleum products terminals revenues of $6.8 million due to higher revenues at both our marine and inland terminals. Marine revenues increased primarily due to operating results from expansion projects, such as construction of additional storage tanks at our Galena Park, Texas facility that were placed into service beginning in late 2006 and throughout 2007, and more revenue from additive services and higher storage rates. The revenue increase at our marine terminals was partially offset by lower revenue recognized from variable-rate storage agreements in 2007. Revenues from these agreements are based on our share of our customer's net trading profits earned during the agreement term and are recognized at the end of that term. Our 2006 results benefitted from shared profits from two variable-rate storage agreements whereas the 2007 period benefitted from only one contract. Inland terminal revenues also increased in 2007 from record throughput volumes as well as higher additive fees; and
- an increase in ammonia pipeline system revenues of $1.8 million primarily due to higher average tariffs.

Operating expenses increased by $7.1 million as higher expenses at our petroleum products terminals and ammonia pipeline system were partially offset by lower costs related to our petroleum products pipeline system as described below:

- a decrease in petroleum products pipeline system expenses of $10.3 million primarily due to more favorable product overages (which reduce operating expenses), lower integrity spending because of maintenance project timing and lower environmental expenses. During the 2006 period, we recognized additional expense when we entered into a risk transfer agreement, whereby risks associated with certain known environmental sites were transferred to a contractor in order to mitigate our future financial exposure relative to those sites. Higher property taxes, asset retirements, power and personnel costs in 2007 partially offset these favorable expense items;
- an increase in petroleum products terminals expenses of $9.0 million primarily related to higher personnel costs, in part due to expansion projects, timing of maintenance projects and product downgrade charges resulting from the accidental degradation of small amounts of product during 2007; and
- an increase in ammonia pipeline system expenses of $7.4 million primarily due to increased environmental accruals related to a 2004 pipeline release and higher system integrity costs.

Product margin increased $16.4 million. Product sales revenues primarily resulted from a third-party product supply agreement, our petroleum products blending activities, petroleum products terminal product gains and transmix fractionation. The increase in 2007 margins was primarily attributable to higher product prices.

Operating margin increased $59.5 million, primarily due to higher revenues from each of our business segments and higher gross margin from product sales in 2007.

Depreciation and amortization expense increased by $2.8 million related to capital expansion projects over the 2007 year.

Affiliate G&A expense increased by $5.5 million between periods primarily due to higher personnel costs during 2007. For the years ended December 31, 2006 and 2007, we were responsible for paying G&A costs of

$53.2 million and $57.4 million, respectively. MGG reimbursed us for our actual cash G&A costs that exceeded these amounts. The amount of G&A reimbursed to us for the years ended December 31, 2006 and 2007 was $1.7 million and $4.1 million, respectively.

Interest expense, net of interest capitalized and interest income, decreased $2.0 million. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased to $887.5 million during 2007 from $807.2 million during 2006. However, the weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, decreased to 6.4% for the 2007 period from 7.1% for the 2006 period primarily due to the refinancing of our pipeline notes during second quarter 2007 at a lower interest rate. Further, the amount of interest capitalized increased due to the higher level of capital spending during 2007.

We recognized debt refinancing expenses of $2.7 million during the 2007 period with no similar expense in 2006. These expenses 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.

Provision for income taxes was $1.6 million during 2007 with no similar expense in 2006. Beginning in 2007, the state of Texas implemented a partnership-level tax based on the financial results of our net revenues apportioned to the state of Texas.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $304.7 million, $260.9 million and $435.6 million for the years ended December 31, 2006, 2007 and 2008, respectively.

- The $174.7 million increase from 2007 to 2008 was primarily attributable to:
  - a $65.2 million increase in net income, excluding the $26.5 million non-cash gain on assignment of supply agreement and a $12.1 million non-cash reduction in our operating expenses resulting from our favorable settlement of a civil penalty related to historical product releases;
  - 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
  - a $33.4 million increase in cash resulting from a $24.9 million decrease in accounts receivable and other accounts receivable in 2008 versus an $8.5 million increase in accounts receivable and other accounts receivable in 2007. The decrease during 2008 is primarily due to a significant decrease in product prices during the latter part of 2008.

  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.
- The $43.8 million decrease from 2006 to 2007 was primarily attributable to:
  - a $15.5 million decrease in cash resulting from a $28.9 million increase in inventory in 2007 versus a $13.4 million increase in inventory in 2006. The increase in inventory during 2007 is primarily due to higher product prices;
  - a $27.6 million decrease in cash resulting from an $11.5 million decrease in accounts payable in 2007 versus a $16.1 million increase in accounts payable in 2006 due primarily to the timing of invoices received from our vendors and suppliers; and

> a $48.2 million decrease in cash resulting from a $19.9 million decrease in accrued product purchases in 2007 versus a $28.3 million increase in accrued product purchases in 2006 due primarily to the timing of invoices received from our vendors and suppliers.

These decreases were partially offset by a $50.1 million increase in net income in 2007.

Net cash used by investing activities for the years ended December 31, 2006, 2007 and 2008 was $148.3 million, $193.7 million and $305.9 million, respectively. 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. Significant expansion capital expenditures during 2008 included new storage tanks at our Wilmington, Delaware and Galena Park, Texas terminals. Additionally, we acquired petroleum products terminals in Bettendorf, Iowa and Wrenshall, Minnesota and a petroleum products terminal in Mount Pleasant, Texas along with a 76-mile petroleum products pipeline for $38.3 million plus related liabilities assumed of $2.6 million. Significant expansion capital expenditures during 2006 and 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. During 2007, we spent $190.2 million for capital expenditures, which included $39.7 million for maintenance capital and $150.5 million for expansion capital. During 2006, we spent $168.5 million for capital expenditures, which included $32.9 million for maintenance capital and $135.6 million for expansion capital.

Net cash used by financing activities for the years ended December 31, 2006, 2007 and 2008 was $186.5 million, $73.7 million and $96.5 million, respectively. Cash distributions paid to our unitholders and general partner were $208.0 million, $236.1 million and $267.2 million during 2006, 2007 and 2008, respectively. During 2008, borrowings under notes 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 borrowings on the revolver during 2008, excluding repayment of the $212.0 million, were $118.5 million, which were used for general purposes including expansion capital expenditures. Net borrowings on our revolving credit facility of $143.0 million and a debt issuance of $248.9 million provided cash during 2007. A portion of these borrowings was used to repay the $272.6 million remaining balance on our pipeline notes. Capital contributions from our general partner during 2008 were $3.3 million, primarily due to payments we received for G&A expense reimbursements. Capital contributions from our general partner of $28.7 million and $40.2 million during 2006 and 2007, respectively, primarily related to payments we received under our May 2004 environmental indemnity settlement and amounts received for G&A reimbursements.

During 2008, we paid $267.2 million in cash distributions to our unitholders and general partner. The quarterly distribution amount associated with the fourth quarter of 2008 was $0.71 per unit, which was paid in February 2009. If we continue to pay cash distributions at this current level and the number of outstanding units remains the same as after the issuance of 210,149 common units representing limited partner interests in us on January 23, 2009 (see Note 22—Subsequent Events in the accompanying consolidated financial statements), total cash distributions of $284.1 million would be paid to our unitholders in 2009, of which $93.9 million, or 33%, would be related to our general partner's approximate 2% ownership interest and incentive distribution rights.

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 2008, our maintenance capital spending was $46.9 million, including $3.6 million of spending that would have been covered by the May 2004 indemnification settlement or for which we expect reimbursement. We have received the entire $117.5 million under our indemnification settlement agreement. Please see "Environmental" below for additional description of this agreement.

For 2009, we expect to incur maintenance capital expenditures for our existing businesses of approximately $42.0 million, including $7.0 million of maintenance capital that has already been reimbursed to us through our indemnification settlement or will be reimbursed by third parties.

In addition to maintenance capital expenditures, we also incur expansion capital expenditures at our existing facilities. During 2008, we spent $225.2 million for organic growth projects and $40.9 million (including $2.6 million of assumed liabilities) to acquire two petroleum products terminals already connected to our petroleum products pipeline system and a petroleum products terminal along with a 76-mile petroleum products pipeline. Based on the progress of expansion projects already underway, we expect to spend approximately $215.0 million of growth capital during 2009, with an additional $30.0 million in 2010 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 any of the banks committed to fund our revolving credit facility were unable to perform on their commitments, our liquidity could be impaired, which could reduce our ability to fund growth capital expenditures and acquisitions. Current market conditions have resulted in higher credit spreads on long-term borrowings and significantly reduced demand for new corporate debt issues. Equity prices, including our own unit price, have experienced abnormally high volatility during the current period. If these conditions persist, our cost of capital could increase and our ability to finance growth capital expenditures or acquisitions in a cost-effective manner could be reduced.

As of December 31, 2008, total debt reported on our consolidated balance sheet was $1,083.5 million. The difference between this amount and the $1,070.0 million face value of our outstanding debt results from adjustments related to unamortized discounts on debt issuances and the unamortized portion of gains recognized on derivative financial instruments which had qualified as fair value hedges of our long-term debt until the hedges were terminated or hedge accounting treatment was discontinued. At December 31, 2008, maturities of our debt were as follows: $0 each year in 2009, 2010 and 2011; $70.0 million in 2012; $0 in 2013; and $1.0 billion thereafter. Our debt is non-recourse to our general partner.

Revolving credit facility. The total borrowing capacity under our revolving credit facility, which matures in September 2012, is $550.0 million. Borrowings under the facility are unsecured and incur interest at LIBOR plus a spread that ranges from 0.3% to 0.8% based on our credit ratings and on amounts outstanding under the facility. As of December 31, 2008, $70.0 million was outstanding under this facility, and $3.9 million of the facility was obligated for letters of credit. The obligations for letters of credit are not reflected as debt on our consolidated balance sheets. As of December 31, 2008, the weighted-average interest rate on borrowings outstanding under this facility was 4.8%. Additionally, a commitment fee is assessed at a rate from 0.05% to 0.125%, depending on our credit rating.

6.45% notes due 2014. In May 2004, we sold $250.0 million of 6.45% notes due 2014 in an underwritten public offering at 99.8% of par. Including the impact of amortizing the gains realized on pre-issuance hedges associated with these notes, the effective interest rate of these notes is 6.3%.

5.65% notes due 2016. In October 2004, we sold $250.0 million of 5.65% notes due 2016 in an underwritten public offering as part of the long-term financing of pipeline system assets we acquired in October 2004. The notes were issued at 99.9% of par. We used an interest rate swap to effectively convert $100.0 million of these notes to floating-rate debt until May 2008 (see "*Interest rate derivatives*" below). Including the amortization of the $3.8 million gain realized from unwinding that interest rate swap and the amortization of losses realized on pre-issuance hedges associated with these notes, the weighted-average interest rate of these notes at December 31, 2008 was 5.7%. The outstanding principal amount of the notes was increased $2.7 million at December 31, 2007 for the fair value of the associated swap-to-floating derivative instrument and $3.5 million at December 31, 2008 for the unamortized portion of the gain recognized upon termination of the aforementioned swap.

6.40% notes due 2018. In July 2008, we issued $250.0 million of 6.40% notes due 2018 in an underwritten public offering. Net proceeds from the offering, after underwriter discounts of $1.6 million and offering costs of $0.4 million, were $248.0 million. The net proceeds were used to repay the $212.0 million of borrowings outstanding under our revolving credit facility at that time, with the balance used for general purposes. In connection with this offering, we entered into $100.0 million of interest rate swap agreements to hedge against changes in the fair value of a portion of these notes, effectively converting $100.0 million of these notes to floating-rate debt (see "*Interest rate derivatives*" below). These agreements originally expired on July 15, 2018, the maturity date of the 6.40% notes; however, in December 2008 we terminated $50.0 million of these agreements and discontinued hedge accounting on the remaining $50.0 million, resulting in our recognizing gains of $11.7 million. The outstanding principal amount of the notes was increased by $11.7 million at December 31, 2008 for the unamortized portion of those gains. Including the amortization of those gains, the weighted-average interest rate of these notes at December 31, 2008 was 5.9%.

6.40% notes due 2037. In April 2007, we sold $250.0 million of 6.40% notes due 2037 in an underwritten public offering at 99.6% of par. We received proceeds of approximately $246.4 million after underwriters' fees and expenses. The net proceeds from the offering of these notes together with borrowings under our revolving credit facility were used in May 2007 to prepay the $272.6 million of outstanding pipeline notes, as well as a related debt prepayment premium of $2.0 million and a $1.1 million payment in connection with the unwinding of fair value hedges associated with the pipeline notes. Including the impact of amortizing the gains realized on pre-issuance hedges associated with these notes, the effective interest rate on these notes is 6.3%.

The debt instruments described above include various covenants. In addition to certain financial ratio covenants, these covenants limit our ability to, among other things, incur indebtedness secured by certain liens, encumber our assets, make certain investments, 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, 2008.

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

Interest rate derivatives. We utilize interest rate derivatives to help us manage interest rate risk. As of December 31, 2008, we had two offsetting interest rate swap agreements outstanding:

- 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% and terminates in July 2018. 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 on Derivative A. The $5.4 million fair value of Derivative A at that time was recorded as an adjustment to long-term debt and is being amortized over the remaining life of the 6.40% fixed-rate notes due 2018. The fair value of Derivative A as of December 31, 2008 was $7.5 million, of which $0.3 million was recorded to other current assets and $7.2 million was recorded to noncurrent assets. The change in fair value of Derivative A from the date we discontinued hedge accounting until December 31, 2008, was a gain of $1.9 million, which was recorded to other (income) expense on our consolidated statement of income.

- In December 2008, concurrent with the discontinuance of hedge accounting treatment of Derivative A described above, we entered into an offsetting $50.0 million interest rate swap agreement with a different financial institution pursuant to which we pay a fixed rate of 6.40% and receive a floating rate of six-month LIBOR plus 3.23%. This agreement terminates in July 2018. We entered into this agreement to offset changes in the fair value of Derivative A, excluding changes due to changes in counterparty credit risks. We did not designate this agreement as a hedge for accounting purposes. The fair value of this agreement as of December 31, 2008 was $(1.8) million, which was recorded to other deferred liabilities on our consolidated balance sheet.

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, 2008 (in millions):

	Total	< 1 year	1-3 years	3-5 years	> 5 years
Long-term debt obligations(1)	$1,070.0	$ —	$ —	$ 70.0	$1,000.0
Interest obligations(2)	816.3	66.0	132.1	127.3	490.9
Operating lease obligations	22.0	3.4	6.6	3.9	8.1
Pension and postretirement medical obligations	32.4	7.5	6.7	1.7	16.5
Purchase commitments:					
Product purchase commitments(3)	8.0	8.0	—	—	—
Utility purchase commitments	2.6	0.8	1.2	0.6	—
Derivative financial instruments(4)					
Equity-based incentive awards(5)	14.8	8.4	6.4	—	—
Environmental remediation(6)	18.0	5.9	5.5	2.0	4.6
Capital project purchase obligations	19.0	19.0	—	—	—
Maintenance obligations	16.7	12.2	2.9	1.6	—
Other purchase obligations	1.6	1.3	0.3	—	—
Total	$2,021.4	$132.5	$161.7	$207.1	$1,520.1

(1) For purposes of this table, we have assumed that the borrowings under our revolving credit facility as of December 31, 2008 ($70.0 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, 2008 will remain outstanding until the maturity date of that facility. The interest obligation further assumes the weighted-average borrowing rate of the facility at December 31, 2008 (4.8%).

(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 we are unable to determine what the amounts, if any, of that commitment might be.

(4) On December 31, 2008, we had two offsetting interest rate swap agreements, each with a notional value of $50.0 million. Because future net cash outflows under these derivative agreements, 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, 2008 fair value of award grants accounted for as liabilities, based on when those outstanding award grants will be settled. Settlements of these awards will differ from these reported amounts primarily due to differences between actual and current estimates of payout percentages and changes in our unit price between December 31, 2008 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 ($4.6 million as of December 31, 2008) and the estimated timing of these payments. Additionally, this agreement requires us to pay the contract counter-party a performance bonus if the remediation sites are brought to contractual end-point for less than $14.3 million. The table above includes our estimate of the performance bonus ($2.2 million) as of December 31, 2008. 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 ($10.7 million as of December 31, 2008) 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).

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, 2008, known liabilities that would have been covered by these indemnifications were estimated to be $25.5 million. Through December 31, 2008, we have spent $59.0 million of the indemnification settlement proceeds for indemnified matters, including $23.1 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.

Petroleum products EPA issue. In July 2001, the Environmental Protection Agency ("EPA"), pursuant to Section 308 of the Clean Water Act (the "Act"), served an information request to a former affiliate with regard to petroleum discharges from its pipeline operations. That inquiry primarily focused on the petroleum products pipeline system that we subsequently acquired. The EPA added to their original demand two subsequent releases that occurred from our petroleum products pipeline system. In September 2008, we paid a penalty of $5.3 million and agreed to perform certain operational enhancements under the terms of a settlement agreement reached with the EPA and Department of Justice ("DOJ"). This agreement led to a reduction of our environmental liability for these matters from $17.4 million to $5.3 million and a reduction of our operating expenses of $12.1 million during second quarter 2008.

Ammonia EPA issue. In February 2007, 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 Act with respect to two releases of anhydrous ammonia from the ammonia pipeline owned by us and, at the time of the releases, operated by a third party. The DOJ stated that the maximum statutory penalty for alleged violations of the Act for both releases combined was approximately $13.2 million. The DOJ also alleged that the third-party operator of our ammonia pipeline was liable for penalties pursuant to Section 103 of the Comprehensive Environmental Response, Compensation and Liability Act for failure to report the releases on a timely basis, with the statutory maximum for those penalties as high as $4.2 million for which the third-party operator has requested indemnification. In March 2007, we also received a demand from the third-party operator for defense and indemnification in regards to a DOJ criminal investigation regarding whether certain actions or omissions of the third-party operator constituted violations of federal criminal statutes. The third-party operator has subsequently settled this criminal investigation with the DOJ by paying a $1.0 million fine. We believe that we do not have an obligation to indemnify or defend the third-party operator for the DOJ criminal fine settlement. The DOJ stated in its notice to us that it does not expect us or the third-party operator to pay the penalties at the statutory maximum; however, it may seek injunctive relief if the parties cannot agree on any necessary corrective actions. We have accrued an amount for these matters based on our best estimates that is less than the maximum statutory penalties. We are currently in discussions with the EPA, DOJ and the third-party operator regarding these two releases; however, we are unable to determine what our ultimate liability could be for these matters. Adjustments to our recorded liability, which could occur in the near term, could be material to our results of operations and cash flows.

Other Items

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%. Based on an actual change in PPI-FG of approximately 3.9% during 2007, we increased virtually all of our published tariffs by the allowed adjustment of approximately 5.2% effective July 1, 2008. The preliminary change in PPI-FG for 2008 is approximately 6.4%. At this level, we would be allowed to increase our indexed rates by an amount up to 7.7% subject to market conditions.

Board of directors of our general partner. The total number of directors on our general partner's board of directors is currently set at eight and there are four vacancies. Three of the vacancies were created when representatives of MGG Midstream Holdings, L.P. ("MGG MH"), a former affiliate, resigned from our board in 2006 and 2008 in conjunction with various governance changes. The fourth vacancy was due to the death of one of three independent directors on December 29, 2008. The New York Stock Exchange corporate governance listing standards require all publicly traded companies to have at least three independent directors serving on the audit committee. On December 30, 2008, we notified the New York Stock Exchange of the director's death and the New York Stock Exchange notified us of our non-compliance. We are currently searching for a third independent director to serve on the board and audit committee.

Customer bankruptcy. Flying J Inc. ("Flying J") and its subsidiaries, including Longhorn Pipeline Partners, L.P. ("Longhorn"), filed for chapter 11 bankruptcy protection during December 2008. We have an agreement with Longhorn under which we operate the Longhorn pipeline for a fee. Bankruptcy proceedings are inherently unpredictable and the bankruptcy court could make decisions that we cannot foresee at this time. We are currently unable to determine what effect Flying J's bankruptcy filing might have on our consolidated results of operations, cash flows or financial position.

Assignment of Supply Agreement. As part of our acquisition of a pipeline system in October 2004, we assumed a third-party supply agreement. Under this agreement, we were obligated to supply petroleum products to one of our customers until 2018. At the time of this acquisition, we believed that the profits we would receive from the supply agreement were below the fair value of our tariff-based shipments on this pipeline and we established a liability for the expected shortfall. On March 1, 2008, we assigned this supply agreement and sold related inventory of $47.6 million to a third-party entity. Further, we returned our former customer's cash deposit, which was $16.5 million at the time of the assignment. During first quarter 2008, we obtained a full release from the supply customer; therefore, we 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, we wrote off the unamortized amount of the liability and recognized a gain of $26.5 million.

Excluding transportation revenues for products shipped under this product supply agreement, we recognized an operating loss of $0.4 million for the year ended December 31, 2006 and an operating profit of $12.4 million for the year ended 2007 related to the supply agreement.

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 $2.4 million as of December 31, 2008. 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.

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, 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, 2006 were as follows (in millions):

Balance	2007		Balance	2008				Balance
12-31-06	Accruals	Expenditures	12-31-07	Accruals	Expenditures	Settlements	Acquisitions	12-31-08
$57.8	$11.1	$(11.1)	$57.8	$9.7	$(16.1)	$(12.1)	$2.5	$41.8

During 2007, we increased our environmental liability accruals by $11.1 million. The increase was due to changes in cost estimates associated with historical releases of $7.8 million, accrual increases related to product releases which occurred in 2007 of $1.6 million and other accrual increases of $1.7 million.

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 in the current year of $3.4 million. Further, we assumed $2.5 million of liabilities associated with acquisitions completed during 2008. Our environmental liabilities at December 31, 2008 included $4.5 million of amounts we believe will be reimbursed by our insurance carriers.

Our environmental liabilities at December 31, 2008 are 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 as much as 35% and assuming that none of this increase was covered by indemnifications or insurance, our operating expenses would increase and operating profit and net income would decrease by approximately $14.6 million, which represents a decrease of 4% of our operating profit and net income for 2008. Assuming this additional expense was incurred ratably throughout the 2008 year, basic and diluted net income per limited partner unit would have been reduced by approximately $0.11 and $0.10, respectively. 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 long-term 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 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, 2007 and 2008, the gross book value of our property, plant and equipment was $2.4 billion and $2.7 billion, respectively, and we recorded depreciation expense of $62.2 million and $69.6 million during 2007 and 2008, 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 37 years. If the estimates of our asset lives changed such that the average estimated asset life was reduced from 37 years to 30 years, our depreciation expense for 2008 would have increased and operating profit and net income would have decreased by $17.2 million. This represents a decrease of 4% of our operating profit and 5% of net income for 2008. Assuming this additional expense was incurred ratably throughout the 2008 year, basic and diluted net income per limited partner unit would have been reduced by approximately $0.13 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 December 31, 2007 and 2008, we had goodwill of $23.9 million and $26.8 million, respectively. 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 Statement of Financial Accounting Standard ("SFAS") No. 142, *Goodwill and Other Intangible Assets*, we test goodwill at the reporting unit level for impairment annually as of October 1st 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 SFAS No. 142 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 SFAS No. 142 during 2006, 2007 and 2008.

Other Intangibles. At December 31, 2007 and 2008, other intangibles, net of accumulated amortization were $7.1 million and $5.5 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, 2008 was approximately 9 years.

Impairment of Long-Lived Assets. As prescribed by SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets (as amended)*, 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 2006, we recorded a $3.0 million impairment of our Menard, Illinois terminal and during 2007 we recorded a $2.2 million impairment of certain sections of our pipeline in Illinois and Missouri (most of which were idle). Impairments recorded during 2008 were insignificant. We have recognized no other impairments during 2006, 2007 or 2008. 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 December 2008, the FASB issued FASB Staff Position ("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 assumptions, (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. Adoption of this FSP will not have a material impact on our financial position, results of operations or cash flows.

In September 2008, the FASB issued EITF No. 08-6 Equity Method Investment Accounting Considerations. This EITF requires entities to measure its 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 Accounting Principles Bulletin 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 is effective in fiscal years beginning on or after December 15, 2008, and interim periods within those fiscal years and is to be applied prospectively. Earlier application by an entity that has previously adopted an alternative accounting policy is not permitted. Adoption of this EITF will 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 clarifies 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 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years with prior period earnings per unit data retrospectively adjusted. Early application of this FSP is not permitted. Adoption of this FSP will not have a material impact on our financial position, results of operations or cash flows.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*. This statement identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements that are presented in conformity with GAAP in the United States. The statement will not change our current accounting practices.

In April 2008, the FASB issued FSP No. FAS 142-3, *Determination of the Useful Life of Intangible Assets*. This FSP amends 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 expands the disclosures required for recognized intangible assets. This FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. Early adoption is prohibited. Adoption of this FSP will 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. For purposes of calculating earnings per unit, our current accounting practice is to allocate net income to the general partner based on the general partner's share of total or proforma distributions, as appropriate, including incentive distribution rights. The effect of adopting this EITF will be: (i) for periods when net income exceeds distributions, our reported earnings per limited partner unit will be higher than under our current accounting practice and (ii) for periods when distributions exceed net income, our reported earnings per limited partner unit will be lower than under our current accounting practice. These differences will be material for those periods where there are material differences between our net income and the distributions we pay. For example, had we applied EITF 07-4 to our prior reporting periods, basic and diluted earnings per limited partner unit would have been as follows:

	(in thousands, except per unit amounts)		
	Under EITF No. 07-4	As Reported	Difference
2006			
Net income allocated to limited partners	$146,858	$148,881	$ (2,023)
Basic and diluted earnings per unit	$ 2.21	$ 2.24	$ (0.03)
2007			
Net income allocated to limited partners	$179,223	$173,330	$ 5,893
Basic and diluted earnings per unit	$ 2.69	$ 2.60	$ 0.09
2008			
Net income allocated to limited partners	$251,710	$219,136	$32,574
Basic earnings per unit	$ 3.77	$ 3.28	$ 0.49
Diluted earnings per unit	$ 3.76	$ 3.27	$ 0.49

This EITF is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. Early application is not permitted. This EITF is required to be applied retrospectively; therefore, we will restate prior period earnings per limited partner unit in all published financial reports after January 1, 2009, as applicable.

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 amends 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 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We do not expect that our adoption of this statement will have a material impact 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 does 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 is effective with the initial adoption of SFAS No. 157, which we adopted on January 1, 2007. Adoption of this FSP did not have a material effect on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations*. This Statement requires, among other things, that entities; (i) recognize, with certain exceptions, 100% of the fair values of assets acquired, liabilities assumed and non-controlling interests in acquisitions of less than a 100% controlling interest when the acquisition constitutes a change in control of the acquired entity; (ii) measure acquirer shares issued in consideration for a business combination at fair value on the acquisition date; (iii) recognize contingent consideration arrangements at their acquisition-date fair values, with subsequent changes in fair value generally reflected in earnings; (iv) recognize, with certain exceptions, pre-acquisition loss and gain contingencies at their acquisition-date fair values; (v) expense, as incurred, acquisition-related transaction costs; and (vi) capitalize acquisition-related restructuring costs only if the criteria in SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities (as amended)* are met as of the acquisition date. This Statement is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. Early application is prohibited. We do not expect the initial adoption of this Statement to have a material impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 160, *Non-Controlling Interests in Consolidated Financial Statements*. This Statement requires, among other things, that: (i) the non-controlling interest be clearly identified and presented in the consolidated statement of financial position within equity, but separate from the parent's equity; (ii) the amount of consolidated net income attributable to the parent and to the non-controlling interest be clearly identified and presented on the face of the consolidated statement of income; (iii) all changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently (as equity transactions); (iv) when a subsidiary is deconsolidated, any retained non-controlling equity investment in the former subsidiary be initially measured at fair value. The gain or loss on the deconsolidation of the subsidiary is measured using the fair value of any non-controlling equity investment rather than the carrying amount of that retained investment; and (v) sufficient disclosures be made to clearly identify and distinguish between the interests of the parent and the interests of non-controlling owners. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is prohibited. We do not expect this Statement to have a material impact on our financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities.* This Statement permits entities to choose to measure many financial instruments and certain other items at fair value, with the objective of mitigating volatility in reported earnings caused by measuring related assets and liabilities differently (without being required to apply complex hedge accounting provisions). We can make an election at the beginning of each fiscal year beginning after November 15, 2007 to adopt this standard. We currently do not plan to adopt this standard.

In January 2007, the FASB issued Revised Statement 133 Implementation Issue No. G19, *Cash Flow Hedges: Hedging Interest Rate Risk for the Forecasted Issuances of Fixed-Rate Debt Arising from a Rollover Strategy.* This Implementation Issue clarified that in a cash flow hedge of a variable-rate financial asset or liability, the designated risk being hedged cannot be the risk of changes in its cash flows attributable to changes in the specifically identified benchmark rate if the cash flows of the hedged transaction are explicitly based on a different index. This Implementation Issue did not have a material impact on our financial position, results of operations or cash flows.

In January 2007, the FASB issued Statement 133 Implementation Issue No. G26, *Cash Flow Hedges: Hedging Interest Cash Flows on Variable-Rate Assets and Liabilities That Are Not Based on a Benchmark Interest Rate.* This Implementation Issue clarified, given the guidance in Implementation Issue No. G19, that an entity may hedge the variability in cash flows by designating the hedged risk as the risk of overall changes in cash flows. This Implementation Issue did not have a material impact on our financial position, results of operations or cash flows.

Related Party Transactions

Affiliate Entity Transactions

We own a 50% interest in a crude oil pipeline company and are paid a management fee for its operation. During each of 2006, 2007 and 2008 we received operating fees from this company of $0.7 million, which we reported as affiliate management fee revenue.

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

	Year Ended December 31,		
	2006	2007	2008
MGG GP—allocated operating expenses	$73,920	$81,184	$84,460
MGG GP—allocated G&A expenses	40,830	45,300	47,658
MGG MH, L.P.—allocated G&A expenses	3,000	2,149	440

Under our services agreement with MGG GP, we reimburse MGG GP for costs of employees necessary to conduct our operations. The current affiliate payroll and benefits accruals associated with this agreement at December 31, 2007 and 2008 were $23.4 million and $18.1 million, respectively, and the long-term affiliate pension and benefits accruals associated with this agreement at December 31, 2007 and 2008 were $22.4 million and $31.8 million, respectively. We settle our affiliate payroll, payroll-related expenses and non-pension postretirement benefit costs with MGG GP on a monthly basis. We settle our long-term affiliate pension liabilities through payments to MGG GP when MGG GP makes contributions to its pension funds.

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 by MGG to us under this agreement was $1.7 million, $4.1 million and $1.6 million in 2006, 2007 and 2008, respectively. We will not receive reimbursements under this agreement beyond 2008.

A former executive officer of our general partner had an investment in MGG MH, an affiliate that, until December 2008, indirectly owned a portion of our general partner. This former executive officer left the company during the fourth quarter of 2006 and we recognized $3.0 million of G&A compensation expenses associated with certain distribution payments made by MGG MH to this individual, with a corresponding increase in partners' capital. During 2007 and 2008, we recognized $2.1 million and $0.4 million, respectively, of G&A compensation expense, with a corresponding increase in partners' capital, for payments made by MGG MH to one of our current executive officers.

Other Related Party Transactions

Until December 2008, MGG, which owns our general partner, was partially owned by MGG MH, which is partially owned by an affiliate of Carlyle/Riverstone Global Energy and Power Fund II, L.P. ("CRF"). During 2006 and the period of January 1 through January 30, 2007, one or more of the members of our general partner's eight-member board of directors was a representative of CRF. At that time, CRF was part of an investment group that purchased Knight, Inc. (formerly known as Kinder Morgan, Inc.). To alleviate competitive concerns the Federal Trade Commission ("FTC") raised regarding this transaction, CRF agreed with the FTC to permanently remove their representatives from our general partner's board of directors, and all of the representatives of CRF voluntarily resigned from the board of directors of our general partner by January 30, 2007.

During 2006 and the period January 1 through January 30, 2007, CRF had total combined general and limited partner interests in SemGroup, L.P. (“SemGroup”) of approximately 30%. During the aforementioned time periods, one of the members of the seven-member board of directors of SemGroup’s general partner was a representative of CRF, with three votes on that board. We were a party to a number of arms-length transactions with SemGroup and its affiliates, which we had historically disclosed as related party transactions. For accounting purposes, we have not classified SemGroup as a related party since the voluntary resignation of the CRF representatives from our general partner’s board of directors as of January 30, 2007. A summary of our transactions with SemGroup during 2006 and the period of January 1 through January 30, 2007 is provided in the following table (in millions):

	Year Ended December 31, 2006	Period From January 1, 2007 Through January 30, 2007
Product sales revenues	$177.1	$20.5
Product purchases	$ 63.2	$14.5
Terminalling and other services revenues	$ 4.4	$ 0.3
Storage tank lease revenues	$ 3.4	$ 0.4
Storage tank lease expense	$ 1.0	$ 0.1

In addition to the above, we provided common carrier transportation services to SemGroup.

One of our general partner’s former independent board members, John P. DesBarres, served as a board member for American Electric Power Company, Inc. (“AEP”) of Columbus, Ohio until December 2008. Mr. DesBarres passed away on December 29, 2008. For the years ended December 31, 2006, 2007 and 2008, our operating expenses included $2.9 million, $2.7 million and $2.8 million, respectively, of power costs incurred with Public Service Company of Oklahoma (“PSO”), which is a subsidiary of AEP. We had no amounts payable to or receivable from PSO or AEP at December 31, 2007 or December 29, 2008.

In connection with the closing of an equity offering completed by MGG in February 2006, we amended our partnership agreement to remove the requirement for our general partner to maintain its 2% interest in any future offering of our limited partner units. In addition, we amended our partnership agreement to restore the incentive distribution rights to the same level as before an amendment made in connection with our October 2004 pipeline system acquisition, which reduced the incentive distributions paid to our general partner by $1.3 million for 2004, $5.0 million for 2005 and $3.0 million for 2006. In return, MGG made a capital contribution to us on February 9, 2006 equal to the present value of the remaining reductions in incentive distributions, or $4.2 million. In January 2007, we issued 185,673 limited partner units primarily to settle the 2004 unit award grants to certain employees, which vested on December 31, 2006. Our general partner did not make an equity contribution associated with this equity issuance and as a result its general partner ownership interest in us changed from 2.000% to 1.995%. In January 2008, we issued 197,433 limited partner units primarily to settle the 2005 unit award grants to certain employees, which vested on December 31, 2007. Our general partner did not make an equity contribution associated with this equity issuance and as a result its general partner ownership interest in us changed from 1.995% to 1.989%. See Note 22—Subsequent Events of Notes to Consolidated Financial Statements, for a discussion of equity issuances and changes in our general partner’s ownership interest that occurred after year-end.

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” 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 that 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 FERC, 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 could 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;
- conflicts of interests between us, our general partner and MGG;
- 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, 2008, we had commitments under forward purchase contracts for product purchases of approximately 135 thousand barrels that will be accounted for as normal purchases totaling approximately $8.4 million, and we had commitments under forward sales contracts for product sales of approximately 175 thousand barrels that will be accounted for as normal sales totaling approximately $8.8 million.

In addition to forward sales agreements, we use NYMEX contracts to lock in forward sales prices. Although these NYMEX agreements represent an economic hedge against price changes on the petroleum products we expect to sell in the future, they do not meet the requirements for hedge accounting treatment under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities (as amended)*; therefore, we have recognized the change in fair value of these agreements currently in earnings. During 2008, we closed our positions on contracts associated with the sale of 495 thousand barrels of gasoline, and we recognized total gains of $30.7 million. At December 31, 2008, the fair value of our open contracts, representing 590 thousand barrels of petroleum product, was $20.2 million, which we recognized as energy commodity derivative contracts on our consolidated balance sheet and as product sales revenues on our current consolidated statement of income. These contracts mature between January 2009 and April 2009. Based on our open NYMEX contracts at December 31, 2008, a $1.00 per barrel increase in the price of regular gasoline would result in a $0.6 million decrease in our product sales revenues and a $1.00 per barrel decrease in the price of regular gasoline would result in a $0.6 million increase in our product sales revenues. 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

As of December 31, 2008, we had $70.0 million outstanding on our variable rate revolving credit facility and had no other variable rate debt outstanding. Considering the amount outstanding on our revolving credit facility as of December 31, 2008, our annual interest expense would change by $0.1 million if LIBOR were to change by 0.125%.

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, 2008 are 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, 2008, based on the results of our assessment, management believes that we have no material weaknesses in internal control over our financial reporting. We maintained effective internal control over financial reporting as of December 31, 2008 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, 2008. The report, which expresses an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2008, 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, 2008, 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, 2008, 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, 2008 and 2007, and the related consolidated statements of income, partners' capital, and cash flows for each of the three years in the period ended December 31, 2008 and our report dated February 26, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 26, 2009

ITEM 8. ***Financial Statements and Supplementary Data***

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, 2008 and 2007, and the related consolidated statements of income, partners' capital, and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of Magellan Midstream Partners, L.P.'s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Magellan Midstream Partners, L.P. at December 31, 2008 and 2007, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 3 to the consolidated financial statements, effective December 31, 2006, Magellan Midstream Partners, L.P. adopted Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*.

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, 2008, 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 26, 2009 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Tulsa, Oklahoma
February 26, 2009

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

	Year Ended December 31, 2006	2007	2008
Transportation and terminals revenues	$ 558,301	$ 607,845	$ 637,958
Product sales revenues	664,569	709,564	574,095
Affiliate management fee revenues	690	712	733
Total revenues	1,223,560	1,318,121	1,212,786
Costs and expenses:			
Operating	244,526	251,601	265,728
Product purchases	605,341	633,909	436,567
Depreciation and amortization	60,852	63,792	71,153
Affiliate general and administrative	67,112	72,587	70,435
Total costs and expenses	977,831	1,021,889	843,883
Gain on assignment of supply agreement	—	—	26,492
Equity earnings	3,324	4,027	4,067
Operating profit	249,053	300,259	399,462
Interest expense	57,478	57,264	56,751
Interest income	(2,097)	(1,767)	(1,478)
Interest capitalized	(2,371)	(4,452)	(4,803)
Debt placement fee amortization	2,681	2,144	767
Debt prepayment premium	—	1,984	—
Other (income) expense	634	728	(375)
Income before provision for income taxes	192,728	244,358	348,600
Provision for income taxes	—	1,568	1,987
Net income	$ 192,728	$ 242,790	$ 346,613
Allocation of net income:			
Limited partners' interest	$ 148,881	$ 173,330	$ 219,136
General partner's interest	43,847	69,460	127,477
Net income	$ 192,728	$ 242,790	$ 346,613
Basic net income per limited partner unit	$ 2.24	$ 2.60	$ 3.28
Weighted-average number of limited partner units outstanding used for basic net income per unit calculation	66,361	66,547	66,855
Diluted net income per limited partner unit	$ 2.24	$ 2.60	$ 3.27
Weighted-average number of limited partner units outstanding used for diluted net income per unit calculation	66,613	66,700	66,927

See notes to consolidated financial statements.

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

	December 31, 2007	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ —	$ 33,241
Accounts receivable (net of allowance for doubtful accounts of $10 and $462 at December 31, 2007 and 2008, respectively)	62,834	37,517
Other accounts receivable	10,696	11,073
Affiliate accounts receivable	208	378
Inventory	120,462	47,734
Energy commodity derivative contracts	—	20,200
Other current assets	10,882	15,440
Total current assets	205,082	165,583
Property, plant and equipment	2,435,890	2,724,326
Less: accumulated depreciation	615,329	674,317
Net property, plant and equipment	1,820,561	2,050,009
Equity investments	24,324	23,190
Long-term receivables	7,506	7,119
Goodwill	23,945	26,809
Other intangibles (net of accumulated amortization of $6,743 and $8,290 at December 31, 2007 and 2008, respectively)	7,086	5,539
Debt placement costs (net of accumulated amortization of $2,170 and $2,937 at December 31, 2007 and 2008, respectively)	6,368	7,649
Other noncurrent assets	6,322	10,217
Total assets	$2,101,194	$2,296,115
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 39,622	$ 39,441
Affiliate accounts payable	12,947	1,942
Affiliate payroll and benefits	23,364	18,119
Accrued interest payable	7,197	15,077
Accrued taxes other than income	21,039	20,151
Environmental liabilities	36,127	19,634
Deferred revenue	20,797	21,492
Accrued product purchases	43,230	23,874
Energy commodity derivatives deposit	—	18,994
Other current liabilities	16,322	16,534
Total current liabilities	220,645	195,258
Long-term debt	914,536	1,083,485
Long-term affiliate payable	1,878	445
Long-term affiliate pension and benefits	22,370	31,787
Supply agreement deposit	18,500	—
Noncurrent portion of product supply liability	24,348	—
Other deferred liabilities	6,081	7,532
Environmental liabilities	21,672	22,166
Commitments and contingencies		
Partners' capital:		
Common unitholders (66,546 units and 66,744 units outstanding at December 31, 2007 and 2008, respectively)	1,192,031	1,274,872
General partner	(309,389)	(296,826)
Accumulated other comprehensive loss	(11,478)	(22,604)
Total partners' capital	871,164	955,442
Total liabilities and partners' capital	$2,101,194	$2,296,115

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2006	2007	2008
Operating Activities:			
Net income	$ 192,728	$ 242,790	$ 346,613
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	60,852	63,792	71,153
Debt placement fee amortization	2,681	2,144	767
Debt prepayment premium	—	1,984	—
Loss on sale and retirement of assets	8,031	8,548	7,180
Equity earnings	(3,324)	(4,027)	(4,067)
Distributions from equity investment	4,125	3,800	5,200
Equity-based incentive compensation expense	10,820	9,994	4,751
Pension settlement expense and amortization of prior service cost and actuarial loss	2,068	3,231	1,310
Gain on assignment of supply agreement	—	—	(26,492)
Changes in components of operating assets and liabilities (Note 3)	26,698	(71,312)	29,156
Net cash provided by operating activities	304,679	260,944	435,571
Investing Activities:			
Property, plant and equipment:			
Additions to property, plant and equipment	(168,544)	(190,182)	(272,083)
Proceeds from sale of assets	6,313	961	3,862
Changes in accounts payable	13,934	(4,434)	661
Acquisitions of businesses	—	—	(38,302)
Net cash used by investing activities	(148,297)	(193,655)	(305,862)
Financing Activities:			
Distributions paid	(207,966)	(236,144)	(267,184)
Net borrowings (payments) under revolver	7,500	143,000	(93,500)
Borrowings under notes	—	248,900	249,980
Payments on notes	(14,345)	(272,555)	—
Debt placement costs	(426)	(2,683)	(2,048)
Payment of debt prepayment premium	—	(1,984)	—
Net receipt from financial derivatives	—	4,556	10,312
Capital contributions by affiliate	28,742	40,205	3,301
Increase in outstanding checks	—	3,026	2,671
Other	14	—	—
Net cash used by financing activities	(186,481)	(73,679)	(96,468)
Change in cash and cash equivalents	(30,099)	(6,390)	33,241
Cash and cash equivalents at beginning of period	36,489	6,390	—
Cash and cash equivalents at end of period	$ 6,390	$ —	$ 33,241
Supplemental non-cash financing activity:			
Issuance of common units in settlement of long-term incentive plan awards	$ —	$ 7,406	$ 8,536

See notes to consolidated financial statements.

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

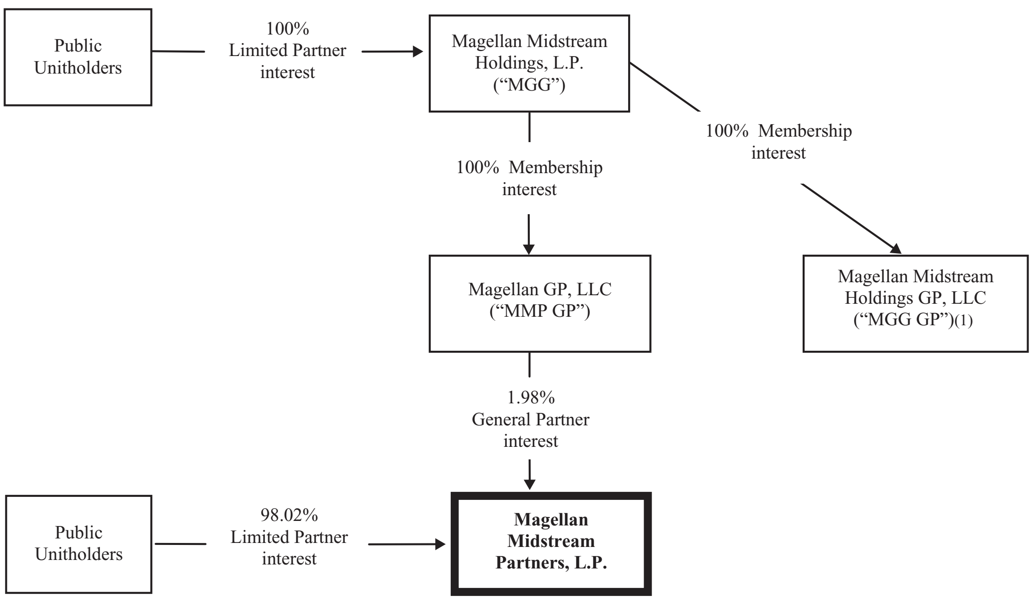
	Common	Subordinated	General Partner	Accumulated Other Comprehensive Loss	Total Partners' Capital
Balance, January 1, 2006	$1,097,391	$ 67,925	$(355,271)	$ (2,055)	$ 807,990
Comprehensive income:					
Net income	151,134	—	41,594	—	192,728
Amortization of loss on cash flow hedges	—	—	—	212	212
Net gain on cash flow hedges	—	—	—	236	236
Adjustment to additional minimum pension liability	—	—	—	343	343
Total comprehensive income					193,519
Adjustment to recognize the funded status of our affiliate postretirement plans	—	—	—	(17,587)	(17,587)
Conversion of subordinated units to common units (5.7 million units)	64,787	(64,787)	—	—	—
Affiliate capital contributions	—	—	28,742	—	28,742
Distributions	(148,497)	(3,138)	(56,331)	—	(207,966)
Equity method incentive compensation expense	1,770	—	—	—	1,770
Other	15	—	(1)	—	14
Balance, December 31, 2006	1,166,600	—	(341,267)	(18,851)	806,482
Comprehensive income:					
Net income	180,839	—	61,951	—	242,790
Net gain on cash flow hedges	—	—	—	5,018	5,018
Amortization of net loss on cash flow hedges	—	—	—	63	63
Pension settlement expense and amortization of prior service cost and net actuarial loss	—	—	—	3,231	3,231
Adjustment to recognize the funded status of our affiliate postretirement plans	—	—	—	(939)	(939)
Total comprehensive income					250,163
Issuance of common units in settlement of 2004 long-term incentive plan awards (0.2 million units)	7,406	—	—	—	7,406
Affiliate capital contributions	—	—	40,205	—	40,205
Distributions	(165,866)	—	(70,278)	—	(236,144)
Equity method incentive compensation expense	3,076	—	—	—	3,076
Other	(24)	—	—	—	(24)
Balance, December 31, 2007	1,192,031	—	(309,389)	(11,478)	871,164
Comprehensive income:					
Net income	251,709	—	94,904	—	346,613
Amortization of net gain on cash flow hedges	—	—	—	(164)	(164)
Amortization of prior service cost and net actuarial loss	—	—	—	1,310	1,310
Adjustment to recognize the funded status of our affiliate postretirement plans	—	—	—	(12,272)	(12,272)
Total comprehensive income					335,487
Issuance of common units in settlement of 2005 long-term incentive plan awards (0.2 million units)	8,536	—	—	—	8,536
Affiliate capital contributions	—	—	3,301	—	3,301
Distributions	(181,542)	—	(85,642)	—	(267,184)
Equity method incentive compensation expense	4,138	—	—	—	4,138
Balance, December 31, 2008	$1,274,872	$ —	$(296,826)	$(22,604)	$ 955,442

See notes to consolidated financial statements.

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

1. Organization, Basis of Presentation and Description of Business

Unless indicated otherwise, the terms "our," "we," "us" and similar language refer to Magellan Midstream Partners, L.P., together with our subsidiaries. We are a publicly traded Delaware limited partnership. Magellan GP, LLC, a Delaware limited liability company, serves as our general partner and owns an approximate 2% general partner interest in us as well as all of our incentive distribution rights. Magellan GP, LLC is a wholly-owned subsidiary of Magellan Midstream Holdings, L.P, a publicly traded Delaware limited partnership. We and Magellan GP, LLC have contracted with Magellan Midstream Holdings GP, LLC to provide all general and administrative ("G&A") services and operating functions required for our operations. Our organizational structure at December 31, 2008, and that of our affiliate entities, as well as how we refer to these affiliates in our notes to consolidated financial statements, is provided below.



(1) MGG GP holds a non-economic general partner interest in MGG.

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. During 2008, we acquired petroleum products terminals in Bettendorf, Iowa and Wrenshall, Minnesota and a petroleum products terminal in Mt. Pleasant, Texas along with a 76-mile petroleum products pipeline for $38.3 million plus related liabilities assumed of $2.6 million. The results of these facilities have been included in our petroleum products pipeline system segment from their respective acquisition dates.

Petroleum Products Pipeline System. Our petroleum products pipeline system includes approximately 8,700 miles of pipeline and 49 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 an ownership interest in Osage

Pipe Line Company, LLC ("Osage Pipeline"), which owns the 135-mile Osage 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.

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. The 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.

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

2. 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.

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. 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 impaired assets. Impaired assets are 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 6—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 Statement of Financial Accounting Standard ("SFAS") No. 143, *Accounting for Asset Retirement Obligations* and Financial Interpretation ("FIN") No. 47, *Accounting for Conditional Asset Retirement Obligations (as amended)*. SFAS No. 143 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. FIN No. 47 clarified 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 rights-of-way agreements typically do not require the dismantling, removal and reclamation of the rights-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 $1.5 million liability associated with anticipated tank liner replacements, we have recorded no liability or corresponding asset in conjunction with SFAS No. 143 and FIN No. 47 as both the amounts and future dates of when such costs might be incurred 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 our 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. We recorded no equity investment impairments during 2006, 2007 or 2008.

Goodwill and Other Intangible Assets. We have adopted SFAS No. 142, *Goodwill and Other Intangible Assets*. In accordance with this Statement, goodwill, which represents the excess of cost over fair value of assets of businesses acquired, is no longer amortized but is evaluated periodically for impairment. Goodwill was $23.9 million and $26.8 million at December 31, 2007 and 2008, respectively. Of our reported goodwill, $23.9 million was acquired in transactions involving our petroleum products terminals segment and $2.9 million was acquired in a transaction 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 4.0% per year, (iii) weighted-average cost of capital of 11.5% based on assumed cost of debt of 8.0%, assumed cost of equity of 15.0% and a 50%/50% 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, 2006, 2007 or 2008. 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 the 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, 2008 was approximately 9 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 2006, 2007 or 2008. Amortization of other intangible assets was $1.6 million during 2006 and $1.5 million during both 2007 and 2008.

Impairment of Long-Lived Assets. We have adopted SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. In accordance with this Statement, 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 significant assets classified as "held for sale" during 2006, 2007 or 2008.

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.

We recorded impairment against the earnings of our petroleum products pipeline system segment of $3.0 million in 2006 and $2.2 million in 2007. Impairments recorded during 2008 were insignificant. The inputs for the valuation models used in determining the fair value of assets we impaired during 2006, 2007 and 2008 are Level 3—Significant Unobservable Inputs as described in SFAS No. 157, *Fair Value Measurements*.

Lease Financings. Direct financing leases are accounted for such that the minimum lease payments plus the unguaranteed residual value accruing to the benefit of the lessor is recorded as the gross investment in the lease. The net investment in the lease is the difference between the total minimum lease payment receivable and the associated unearned income.

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 increase the borrowing capacity of our revolving credit facility, 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.

Capitalization of Interest. 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 three months or longer to complete with total costs exceeding $0.5 million.

Pension and Postretirement Medical and Life Benefit Obligations. MGG GP sponsors three pension plans, which cover substantially all of its employees, a postretirement medical and life benefit plan for selected employees and a defined contribution plan. Our affiliate pension and postretirement benefit liabilities represent the funded status of the present value of benefit obligations of these plans.

MGG GP's 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 MGG GP uses 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. Affiliate liabilities for paid-time off benefits are recognized for all employees performing services for us when earned by those employees. We recognized affiliate paid-time off liabilities of $8.8 million and $9.8 million at December 31, 2007 and 2008, respectively. These balances represent the remaining vested paid-time off benefits of employees who support us. Affiliate liabilities for paid-time off are reflected in the affiliate payroll and benefits balances of the consolidated balance sheets.

Derivative Financial Instruments. We account for derivative instruments in accordance with SFAS No. 133, *Accounting for Financial Instruments and Hedging Activities (as amended)*, 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 hedge item. If we determine that a derivative, originally designated as a cash flow or fair value hedge, is no longer highly effective, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in current earnings. The changes in fair value of derivative financial instruments that either do not qualify for hedge accounting or are not designated a hedging instrument are included in current earnings.

As part of our risk management process, we assess the creditworthiness of the financial and other institutions with which we execute financial derivatives. 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 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, 2008, we had commitments under forward purchase contracts for product purchases of approximately 0.2 million barrels that will be accounted for as normal purchases totaling approximately $8.4 million, and we had commitments under forward sales contracts for product sales of approximately 0.2 million barrels that will be accounted for as normal sales totaling approximately $8.8 million.

We have entered into New York Mercantile Exchange ("NYMEX") commodity based futures contracts to hedge against price changes on the petroleum products we expect to sell in the future. These contracts do not qualify as normal sales or for hedge accounting treatment under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities (as amended)*; therefore, we recognize gains or losses from these agreements currently in earnings. At December 31, 2008, the fair value of our NYMEX agreements, representing 0.6 million barrels of petroleum products, was $20.2 million, which we recognized as energy commodity derivative contracts on our consolidated balance sheet and product sales revenues on our consolidated statement of income.

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

See *Comprehensive Income* in this Note 2 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 shipments of product under published tariffs that combine transportation and terminalling services, shipments are complete when our customer take possession of its product out of 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 our customers. Product sales are increased for gains and decreased for losses associated with the change in fair value of our NYMEX agreements.

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 Terminalling Agreements. Our operations have 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 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 earn related to these shared trading profits) were not determinable until the end of the contract term. For example, trading losses sustained by our customer on the last day of the contract period could offset all trading profits realized up to that point during the year, in which case, the cumulative trading profit over the contract period would be zero. In such a case we would recognize no revenues under the variable-rate portion of the agreement. Based on the circumstances of these agreements and in accordance with Emerging Issues Task Force ("EITF") No. D-96, *Accounting for Management Fees Based on a Formula*, our policy is to defer recognition of the variable-rate portion of revenue from these agreements until the end of the contract term. We recognized $6.4 million of variable-rate terminalling revenues when a contract term expired on January 31, 2006 and $3.0 million, $2.8 million and $0.9 million when a contract term expired on December 31, 2006, 2007 and 2008, respectively.

In March 2008, in conjunction with our assignment of a supply agreement, we entered into a transportation agreement with the assignee under which we agreed to a variable-rate tariff whereby we will share in certain profits and losses on delivery of the underlying product. The agreement is structured such that our share of any losses resulting from this arrangement 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. For the period from inception of the agreement through December 31, 2008, our share of the profits from this agreement in excess of our normal tariff was $1.8 million.

G&A Expenses. Under our services agreement, we paid MGG and MGG GP for direct and indirect G&A expenses incurred on our behalf. Under our omnibus agreement, MGG reimbursed us for the expenses in excess of a G&A cap. The amount of G&A expense reimbursed to us by MGG has been recognized as a capital contribution by our general partner with the associated expense specifically allocated to our general partner.

Equity-Based Incentive Compensation Awards. Our general partner has issued incentive awards of phantom units, without distribution equivalent rights, representing limited partner interests in us to certain employees of MGG GP who support us. In addition, our general partner has issued phantom units with distribution equivalent rights to certain of its directors. These awards are accounted for as prescribed in SFAS No. 123(R), *Share-Based Payments*.

Under SFAS No. 123(R) 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 common units representing limited partner interests in us 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. Compensation expense for liability awards for each period 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 unit-based payments 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 units to be paid out by 20%. Judgments and assumptions of the final award payouts are inherent in the accruals we record for unit-based incentive compensation costs. The use of alternate judgments and assumptions could result in the recognition of different levels of unit-based incentive compensation costs in our financial statements.

Environmental. Environmental expenditures that relate to current or future revenues are expensed or capitalized based upon 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 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 discount these liabilities. At December 31, 2008, expected payments on discounted liabilities were $0.3 million during each year in 2009, 2010 and 2011 and $0.2 million each year in 2012 and 2013 and $4.4 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 15—Commitments and Contingencies for a discussion of the changes in our environmental liabilities between December 31, 2007 and December 31, 2008.

	December 31,	
	2007	2008
Aggregated undiscounted environmental liabilities	$63,346	$47,549
Amount of environmental liabilities discounted	(5,547)	(5,749)
Environmental liabilities, as reported	$57,799	$41,800

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.

We have determined that certain costs would have been covered by indemnifications from a former owner of our general partner, which we have settled (see Note 15—Commitments and Contingencies). We make judgments on what would have been covered by these indemnifications and specifically allocate these costs to our general partner.

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 in our financial statements.

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 in us is not available to us.

During 2006, the state of Texas passed a law that imposed a partnership-level tax on us beginning in 2007 based on the net revenues of our assets apportioned to the state of Texas. This tax is reflected as provision for income taxes in our results of operations for 2007 and 2008.

Allocation of Net Income. For purposes of calculating earnings per unit, we allocate net income to our general partner and limited partners each period under the provisions of EITF Issue No. 03-6, *Participating Securities and the Two-Class Method under FASB Statement No. 128.* Accordingly, for those periods where distributions exceed net income, net income is allocated to our general partner and limited partners based on their contractually-determined cash distributions declared and paid following the close of each quarter (see Note 18—Distributions). Our general partner is also directly charged with specific costs that it has individually assumed and for which the limited partners are not responsible (see Note 4—Allocation of Net Income). For periods where net income exceeds distributions, net income is allocated to our general and limited partners based on their proportionate share of pro forma cash distributions assuming that distributions for the period were equal to net income before direct charges to our general partner. The general partner's proportionate share of net income is further adjusted for direct charges.

For purposes of determining capital balances, for those periods when distributions exceed net income, we allocate net income to our general partner and limited partners based on their proportionate share of contractually-determined cash distributions declared and paid following the close of each quarter with adjustments made for any charges specifically allocated to our general partner. For periods when net income exceeds distributions, we allocate net income to our general partner and limited partners up to the amount of cash distributions paid for that period based on the contractually-determined cash distributions paid to each. The excess of net income over distributions is allocated based on the contractual terms of our partnership agreement. The general partner's proportionate share of income is further adjusted for direct charges.

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. Certain directors of our general partner have been awarded phantom units that carry distribution equivalent rights. These phantom units are included in 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 units outstanding include the dilutive effect of phantom unit grants associated with our long-term incentive plan.

Comprehensive Income. We account for comprehensive income in accordance with SFAS No. 130, *Reporting Comprehensive Income*. Our comprehensive income was determined based on 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 affiliate 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 partners' capital as allowed under SFAS No. 130.

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

	Derivative Gains (Losses)	Minimum Pension Liability	Pension and Postretirement Liabilities	Accumulated Other Comprehensive Loss
Balance, January 1, 2006	$(1,712)	$(343)	$ —	$ (2,055)
Amortization of loss on cash flow hedges	212	—	—	212
Net gain on cash flow hedges	236	—	—	236
Adjustment to additional minimum pension liability	—	343	—	343
Adjustment to recognize the funded status of our affiliate postretirement benefit plans	—	—	(17,587)	(17,587)
Balance, December 31, 2006	(1,264)	—	(17,587)	(18,851)
Net gain on cash flow hedges	5,018	—	—	5,018
Amortization of net loss on cash flow hedges	63	—	—	63
Pension settlement expense and amortization of prior service cost and net actuarial loss	—	—	3,231	3,231
Adjustment to recognize the funded status of our affiliate postretirement benefit plans	—	—	(939)	(939)
Balance, December 31, 2007	3,817	—	(15,295)	(11,478)
Amortization of net gain on cash flow hedges	(164)	—	—	(164)
Amortization of prior service cost and net actuarial loss	—	—	1,310	1,310
Adjustment to recognize the funded status of our affiliate postretirement benefit plans	—	—	(12,272)	(12,272)
Balance, December 31, 2008	$ 3,653	$ —	$(26,257)	$(22,604)

New Accounting Pronouncements

In December 2008, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position ("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 assumptions, (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, (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. The adoption of this FSP will not have a material impact on our financial position, results of operations or cash flows.

In September 2008, the FASB issued EITF No. 08-6 *Equity Method Investment Accounting Considerations*. This EITF requires entities to measure its 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 Accounting Principles Bulletin 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 is effective in fiscal years beginning on or after December 15, 2008, and interim periods within those fiscal years and is to be applied prospectively. Earlier application by an entity that has previously adopted an alternative accounting policy is not permitted. Adoption of this EITF will not have a material impact on our financial position, results of operations or cash flows.

In June 2008, the FASB issued 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 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years with prior period earnings per unit data retrospectively adjusted. Early application of this FSP is prohibited. Adoption of this FSP will not have a material impact on our financial position, results of operations or cash flows.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*. This statement identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements that are presented in conformity with GAAP in the United States. The Statement will not change our current accounting practices.

In April 2008, the FASB issued FSP No. FAS 142-3, *Determination of the Useful Life of Intangible Assets*. This FSP amends 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 expands the disclosures required for recognized intangible assets. This FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. Early adoption is prohibited. Adoption of this FSP will 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. For purposes of calculating earnings per unit, our current accounting practice is to allocate net income to the general partner based on the general partner's share of total or proforma distributions, as appropriate, including incentive distribution rights. The effect of adopting this EITF will be: (i) for periods when net income exceeds distributions, our reported earnings per limited partner unit will be higher than under our current accounting practice and (ii) for periods when distributions exceed net income, our reported earnings per limited partner unit will be lower than under our current accounting practice. These differences will be material for those periods where there are material differences between our net income and the distributions we pay. For example, had we applied EITF 07-4 to our prior reporting periods, basic and diluted earnings per limited partner unit would have been as follows:

	(in thousands, except per unit amounts)		
	Under EITF No. 07-4	As Reported	Difference
2006			
Net income allocated to limited partners	$146,858	$148,881	$ (2,023)
Basic and diluted earnings per unit	$ 2.21	$ 2.24	$ (0.03)
2007			
Net income allocated to limited partners	$179,223	$173,330	$ 5,893
Basic and diluted earnings per unit	$ 2.69	$ 2.60	$ 0.09
2008			
Net income allocated to limited partners	$251,710	$219,136	$32,574
Basic earnings per unit	$ 3.77	$ 3.28	$ 0.49
Diluted earnings per unit	$ 3.76	$ 3.27	$ 0.49

This EITF is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. Early application is not permitted. This EITF is required to be applied retrospectively; therefore, we will restate prior period earnings per limited partner unit in all published financial reports after January 1, 2009, as applicable.

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 amends 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 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Our adoption of this Statement will not have a material impact 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 does 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 is effective with the initial adoption of SFAS No. 157, which we adopted on January 1, 2007. Adoption of this FSP did not have a material effect on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations*. This Statement requires, among other things, that entities; (i) recognize, with certain exceptions, 100% of the fair values of assets acquired, liabilities assumed and non-controlling interests in acquisitions of less than a 100% controlling interest when the acquisition constitutes a change in control of the acquired entity; (ii) measure acquirer shares issued in consideration for a business combination at fair value on the acquisition date; (iii) recognize contingent consideration arrangements at their acquisition-date fair values, with subsequent changes in fair value generally reflected in earnings; (iv) recognize, with certain exceptions, pre-acquisition loss and gain contingencies at their acquisition-date fair values; (v) expense, as incurred, acquisition-related transaction costs; and (vi) capitalize acquisition-related restructuring costs only if the criteria in SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities (as amended)* are met as of the acquisition date. This Statement is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. Early application is prohibited. We do not expect the initial adoption of this Statement to have a material impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 160, *Non-Controlling Interests in Consolidated Financial Statements*. This Statement requires, among other things, that: (i) the non-controlling interest be clearly identified and presented in the consolidated statement of financial position within equity, but separate from the parent's equity; (ii) the amount of consolidated net income attributable to the parent and to the non-controlling interest be clearly identified and presented on the face of the consolidated statement of income; (iii) all changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently (as equity transactions); (iv) when a subsidiary is deconsolidated, any retained non-controlling equity investment in the former subsidiary be initially measured at fair value. The gain or loss on the deconsolidation of the subsidiary is measured using the fair value of any non-controlling equity investment rather than the carrying amount of that retained investment; and (v) sufficient disclosures be made to clearly identify and distinguish between the interests of the parent and the interests of non-controlling owners. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is prohibited. We do not expect this Statement to have a material impact on our financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities.* This Statement permits entities to choose to measure many financial instruments and certain other items at fair value, with the objective of mitigating volatility in reported earnings caused by measuring related assets and liabilities differently (without being required to apply complex hedge accounting provisions). We can make an election at the beginning of each fiscal year beginning after November 15, 2007 to adopt this Statement. We do not plan to adopt this Statement.

In January 2007, the FASB issued Revised Statement 133 Implementation Issue No. G19, *Cash Flow Hedges: Hedging Interest Rate Risk for the Forecasted Issuances of Fixed-Rate Debt Arising from a Rollover Strategy.* This Implementation Issue clarified that in a cash flow hedge of a variable-rate financial asset or liability, the designated risk being hedged cannot be the risk of changes in its cash flows attributable to changes in the specifically identified benchmark rate if the cash flows of the hedged transaction are explicitly based on a different index. The effective date of this guidance for us was April 1, 2007. Our adoption of this Implementation Issue did not have a material impact on our financial position, results of operations or cash flows.

In January 2007, the FASB issued Statement 133 Implementation Issue No. G26, *Cash Flow Hedges: Hedging Interest Cash Flows on Variable-Rate Assets and Liabilities That Are Not Based on a Benchmark Interest Rate.* This Implementation Issue clarified, given the guidance in Implementation Issue No. G19, that an entity may hedge the variability in cash flows by designating the hedged risk as the risk of overall changes in cash flows. Our adoption of this Implementation Issue did not have a material impact on our financial position, results of operations or cash flows.

3. Consolidated Statements of Cash Flows

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

	Year Ended December 31,		
	2006	2007	2008
Accounts receivable and other accounts receivable	$ (8,843)	$ (8,512)	$ 24,940
Affiliate accounts receivable	5,052	275	(170)
Inventory	(13,395)	(28,912)	72,728
Energy commodity derivative contracts, net of margin deposit	—	—	(1,206)
Supply agreement deposit	1,000	5,000	(18,500)
Accounts payable	16,107	(11,493)	(842)
Affiliate accounts payable	921	(3,782)	(2,873)
Affiliate payroll and benefits	1,488	4,688	(5,245)
Accrued interest payable	(362)	(2,069)	7,880
Accrued taxes other than income	153	3,579	(894)
Accrued product purchases	28,326	(19,868)	(19,356)
Current and noncurrent environmental liabilities	(439)	34	(18,549)
Other current and noncurrent assets and liabilities	(3,310)	(10,252)	(8,757)
Total	$ 26,698	$(71,312)	$ 29,156

At December 31, 2006, in accordance with the additional minimum liability provisions of SFAS No. 87, *Employers' Accounting for Pensions* and the transition provisions of SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans,* we increased our long-term affiliate pension and benefits by $15.6 million and certain other accounts by $2.0 million, resulting in a $17.6 million increase in accumulated other comprehensive loss. At December 31, 2007 and 2008, we increased long-term affiliate pension and benefits by $0.9 million and $12.3 million, respectively, resulting in an increase in accumulated other comprehensive loss. These non-cash amounts are not reflected in the statements of cash flows.

4. Allocation of Net Income

For purposes of calculating net income per limited partner unit, the allocation of net income between our general partner and limited partners was as follows (in thousands):

	Year Ended December 31,		
	2006	2007	2008
Allocation of net income to general partner:			
Net income	$192,728	$242,790	$346,613
Direct charges to general partner:			
Reimbursable G&A costs[a]	4,665	6,191	2,072
Previously indemnified environmental charges (credits)	8,987	4,426	(6,416)
Total direct charges (credits) to general partner	13,652	10,617	(4,344)
Income before direct charges (credits) to general partner	206,380	253,407	342,269
General partner's share of income[b]	27.86%	31.60%	35.98%
General partner's allocated share of net income before direct charges (credits)	57,499	80,077	123,133
Direct charges (credits) to general partner	13,652	10,617	(4,344)
Net income allocated to general partner	$ 43,847	$ 69,460	$127,477
Net income	$192,728	$242,790	$346,613
Less: net income allocated to general partner	43,847	69,460	127,477
Net income allocated to limited partners	$148,881	$173,330	$219,136

(a) A former executive officer of our general partner had an investment in MGG MH, which until December 2008 indirectly owned a portion of our general partner. This former executive officer left the company during the fourth quarter of 2006 and we were allocated $3.0 million of G&A compensation expense associated with certain distribution payments made by MGG MH to this individual. 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 MGG MH to one of our current executive officers. Because the limited partners did not share in these costs, they were allocated to our general partner.

(b) For periods when the distributions we pay exceed our net income (before direct charges to the general partner), the general partner's percentage share of income is its proportion of cash distributions paid for the period. For periods when net income exceeds the cash distributions we pay, the general partner's percentage share of income is its proportion of pro forma cash distributions that equal net income (before direct charges to the general partner). Because our net income for the second and fourth quarters of 2006 exceeded cash distributions, under the "two class" method of computing earnings per share, as prescribed by SFAS No. 128, *Earnings Per Share*, earnings were allocated to the general partner and limited partners assuming that all of the net income for those periods had been distributed. The general partner's share of income, as reflected in the table above, was determined from its allocated share of first and third quarter 2006 net income, based on actual cash distributions for those periods, plus its allocated share of net income for the second and fourth quarters of 2006, based on pro forma cash distributions for those periods. During 2007, cash distributions exceeded net income only for the first quarter; therefore, the general partner's share of distributions for the year ended December 31, 2007 was equal to its share of actual distributions paid for the first quarter and pro forma distributions for the second, third and fourth quarters. During 2008, net income exceeded cash distributions for all four quarters; therefore, the general partner's share of distributions for the year ended December 31, 2008 was equal to its share of pro forma distributions for each quarter during the year.

For purposes of determining the capital balances of the general partner and the limited partners, the allocation of net income was as follows (in thousands):

	Year Ended December 31,		
	2006	2007	2008
Allocation of net income to general partner:			
Net income	$192,728	$242,790	$346,613
Direct charges to general partner:			
Reimbursable G&A costs	4,665	6,191	2,072
Previously indemnified environmental charges (credits)	8,987	4,426	(6,416)
Total direct charges (credits) to general partner	13,652	10,617	(4,344)
Income before direct charges (credits) to general partner	206,380	253,407	342,269
General partner's share of income[(a)]	26.77%	28.64%	26.46%
General partner's allocated share of net income before direct charges (credits)	55,246	72,568	90,560
Direct charges (credits) to general partner	13,652	10,617	(4,344)
Net income allocated to general partner	$ 41,594	$ 61,951	$ 94,904
Net income	$192,728	$242,790	$346,613
Less: net income allocated to general partner	41,594	61,951	94,904
Net income allocated to limited partners	$151,134	$180,839	$251,709

(a) For periods when the distributions we pay exceed our net income, the general partner's percentage share of income is its proportion of cash distributions paid for the period. For periods when net income exceeds distributions, we allocate net income to our general partner and limited partners up to the amount of cash distributions paid for that period based on the contractually-determined cash distributions paid to each. The excess of net income over distributions is based on the contractual terms of our partnership agreement. The general partner's proportionate share of income is adjusted for direct charges.

Excluding the payments by MGG Midstream Holdings, L.P. ("MGG MH") to certain of our executive officers of $3.0 million, $2.1 million and $0.4 million in 2006, 2007 and 2008, respectively, the reimbursable G&A costs in the tables above represent G&A expenses charged against our income during the periods presented that were required to be reimbursed to us by our general partner under the terms of the omnibus agreement. Because the limited partners do not share in these costs, we allocated these G&A expense amounts directly to our general partner. We record the reimbursements by our general partner as capital contributions. In 2004, we and our general partner entered into an agreement with a former affiliate to settle certain of our former affiliate's indemnification obligations to us (see Note 15—Commitments and Contingencies). Since our limited partners do not share in these costs, we have allocated the expenses and credits related to this previous indemnification agreement directly to our general partner.

5. Inventory

Inventory at December 31, 2007 and 2008 was as follows (in thousands):

	2007	2008
Refined petroleum products	$ 65,215	$20,917
Transmix	32,824	13,099
Natural gas liquids	16,233	7,534
Additives	5,812	6,184
Other	378	—
Total inventory	$120,462	$47,734

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

The decrease in refined petroleum products inventory from 2007 to 2008 was primarily attributable to the sale of inventory in connection with the assignment of a product supply agreement to a third-party entity effective March 1, 2008, as well as a significant decrease in the prices of products that comprise our inventory during 2008.

6. Property, Plant and Equipment

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

	December 31,		Estimated Depreciable Lives
	2007	2008	
Construction work-in-progress	$ 112,891	$ 120,521	
Land and rights-of-way	52,937	55,069	
Carrier property	1,275,714	1,339,542	6 – 59 years
Buildings	14,514	19,095	20 – 53 years
Storage tanks	411,010	499,457	20 – 40 years
Pipeline and station equipment	210,064	214,701	3 – 59 years
Processing equipment	301,115	405,412	3 – 56 years
Other	57,645	70,529	3 – 48 years
Total	$2,435,890	$2,724,326	

Carrier property is defined as pipeline assets regulated by the FERC. Other includes interest capitalized at December 31, 2007 and 2008 of $22.5 million and $25.4 million, respectively. Depreciation expense for the years ended December 31, 2006, 2007 and 2008 was $59.3 million, $62.2 million and $69.6 million, respectively.

7. Major Customers and Concentration of Risks

Major Customers. The percentage of revenue derived by customers that accounted for 10% or more of our consolidated total revenues is provided in the table below. No other customer accounted for more than 10% of our consolidated total revenue for 2006, 2007 or 2008. The majority of the revenues from Customers A, B and C resulted from sales to those customers of refined petroleum products that we generated in connection with our petroleum products blending and fractionation activities. In general, accounts receivable from these customers are due within 3 days of sale. Prior to August 2006, Customer E purchased petroleum products from us pursuant to a third-party supply agreement. In August 2006, Customer E assigned its rights under this supply agreement to Customer D. In March 2008, we assigned our obligations under this supply agreement to a third party (see Note 21—Assignment of Supply Agreement).

	Year Ended December 31,		
	2006	2007	2008
Customer A	2%	2%	12%
Customer B	1%	1%	12%
Customer C	11%	13%	8%
Customer D	18%	33%	2%
Customer E	29%	0%	0%
Total	61%	49%	34%

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.

The employees assigned to conduct our operations are employees of MGG GP. As of December 31, 2008, MGG GP employed 1,204 employees.

At December 31, 2008, the labor force of 577 employees assigned to our petroleum products pipeline system was concentrated in the central United States. Approximately 37% of these employees were represented by the United Steel Workers Union ("USW"). MGG GP's collective bargaining agreement with the USW was ratified by the union members in February 2009. This agreement expires January 31, 2012. The labor force of 296 employees assigned to our petroleum products terminals operations at December 31, 2008 is primarily concentrated in the southeastern and Gulf Coast regions of the United States. Approximately 10% 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. On July 1, 2008, we assumed operations of our ammonia pipeline from a third-party pipeline company. At December 31, 2008, 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.

8. Employee Benefit Plans

MGG GP sponsors two union pension plans for certain employees ("USW plan" and "IUOE plan"), a pension plan for certain non-union employees ("Salaried plan"), a postretirement benefit plan for selected employees and a defined contribution plan. We are required to reimburse MGG GP for its obligations associated with the pension plans, postretirement benefit plan and defined contribution plan for qualifying individuals assigned to our operations.

In December 2006, we adopted SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans.* Upon adoption of SFAS No. 158, we recognized the funded status of the present value of the benefit obligations of MGG GP's pension plans and its postretirement medical and life benefit plan. The effect of adopting SFAS No. 158 on amounts reported in our consolidated balance sheets is described in Note 3—Consolidated Statement of Cash Flows.

The annual measurement date for the aforementioned plans is December 31. The following table presents the changes in affiliate benefit obligations and plan assets for pension benefits and other postretirement benefits for the years ended December 31, 2007 and 2008 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2007	2008	2007	2008
Change in affiliate benefit obligation:				
Affiliate benefit obligation at beginning of year	$43,849	$ 42,117	$ 15,004	$ 17,069
Service cost	5,765	5,473	533	435
Interest cost	2,539	2,698	1,026	1,029
Plan participants' contributions	—	—	61	108
Actuarial (gain) loss	(837)	2,709	661	1,133
Benefits paid	(951)	(1,799)	(216)	(617)
Pension settlement	(8,248)	—	—	—
Affiliate benefit obligation at end of year	42,117	51,198	17,069	19,157
Change in plan assets:				
Fair value of plan assets at beginning of year	29,416	36,599	—	—
Employer contributions	15,000	9,143	155	509
Plan participants' contributions	—	—	61	108
Actual return on plan assets	1,382	(5,730)	—	—
Benefits paid	(951)	(1,799)	(216)	(617)
Pension settlement	(8,248)	—	—	—
Fair value of plan assets at end of year	36,599	38,213	—	—
Funded status at end of year	$ (5,518)	$(12,985)	$(17,069)	$(19,157)
Accumulated affiliate benefit obligation	$31,139	$ 38,447		

The amounts included in pension benefits in the previous table combine the union pension plans with the Salaried pension plan. At December 31, 2007, the fair value of MGG GP's USW and Salaried pension plans' assets exceeded their respective accumulated benefit obligations and the fair value of the IUOE plan assets was equal to its accumulated benefit obligation. At December 31, 2008, the fair value of the USW plan's assets exceeded the fair value of the accumulated benefit obligation by $1.8 million and the fair value of the Salaried and IUOE plans' assets combined were $2.0 million less than the fair value of their accumulated benefit obligations.

Amounts recognized in our consolidated balance sheets were as follows (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2007	2008	2007	2008
Amounts recognized in the consolidated balance sheet:				
Current accrued benefit cost	$ —	$ —	$ (217)	$ (355)
Long-term accrued benefit cost	(5,518)	(12,985)	(16,852)	(18,802)
	(5,518)	(12,985)	(17,069)	(19,157)
Accumulated other comprehensive loss:				
Net actuarial loss	4,980	15,970	5,384	6,209
Prior service cost	4,131	3,456	800	622
Net amount recognized in consolidated balance sheet	$ 3,593	$ 6,441	$(10,885)	$(12,326)

Net pension and other postretirement benefit expense for the years ended December 31, 2006, 2007 and 2008 consisted of the following (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2006	2007	2008	2006	2007	2008
Components of net periodic pension and postretirement benefit expense:						
Service cost	$ 5,587	$ 5,765	$ 5,473	$ 469	$ 533	$ 435
Interest cost	2,206	2,539	2,698	834	1,026	1,029
Expected return on plan assets	(1,906)	(2,497)	(2,702)	—	—	—
Amortization of prior service cost	678	678	675	177	177	178
Amortization of actuarial loss	538	414	150	675	688	307
Pension settlement expense[(a)]	—	1,274	—	—	—	—
Net periodic expense	$ 7,103	$ 8,173	$ 6,294	$2,155	$2,424	$1,949

(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 $4.1 million, $4.6 million and $5.0 million in 2006, 2007 and 2008, respectively.

The estimated net 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 2009 are $1.3 million and $0.7 million, respectively. The estimated net loss and prior service cost for the other defined benefit postretirement plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2009 are $0.5 million and $0.2 million, respectively.

The weighted-average rate assumptions used to determine benefit obligations as of December 31, 2007 and 2008 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2007	2008	2007	2008
Discount rate—Salaried plan	6.50%	6.00%	N/A	N/A
Discount rate—USW plan	6.50%	6.25%	N/A	N/A
Discount rate—IUOE plan	6.50%	5.75%	N/A	N/A
Discount rate—Other Postretirement Benefits	N/A	N/A	6.50%	5.75%
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, 2006, 2007 and 2008 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2006	2007	2008	2006	2007	2008
Discount rate	5.50%	5.75%	6.50%	5.50%	6.00%	6.50%
Expected rate of return on plan assets	7.00%	7.00%	7.00%	N/A	N/A	N/A
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	N/A	5.00%	5.00%	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 our 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 2009 is 7.5% decreasing systematically to 4.5% by 2018 for pre-65 year-old participants and 9.0% decreasing systematically to 5.3% by 2018 for post-65 year-old participants. The health care cost trend rate assumption has a significant effect on the amounts reported. As of December 31, 2008, 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	$ 299	$ 139
Change in postretirement benefit obligation	$2,827	$2,638

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 our 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. We evaluate risks based on the potential impact on the predictability of contribution requirements, probability of under-funding, expected risk-adjusted returns and investment return volatility. Funds are invested with multiple investment managers. Our target allocation and actual weighted-average asset allocation percentages at December 31, 2007 and 2008 were as follows:

	2007		2008	
	Actual[(a)]	Target	Actual[(a)]	Target
Equity securities	55%	63%	30%	40%
Debt securities	29%	36%	59%	59%
Other	16%	1%	11%	1%

(a) We made cash contributions of $15.0 million and $9.1 million to the pension plans in the 2007 and 2008 fiscal years, respectively. Amounts contributed in 2007 and 2008 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, 2007 and 2008 scheduled for investment in accordance with the target. Excluding these uninvested cash amounts, our actual allocation percentages at December 31, 2007 would have been 66% equity securities and 34% debt securities and at December 31, 2008, would have been 33% equity securities and 67% debt securities. In 2009, these uninvested cash amounts will be invested to bring the total asset allocation in line with the target allocation.

As of December 31, 2008, the benefit amounts expected to be paid through December 31, 2018 were as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2009	$ 1,922	$ 355
2010	2,084	439
2011	2,252	533
2012	2,390	629
2013	2,400	714
2014 through 2018	15,884	4,747

Contributions estimated to be paid in 2009 are $7.2 million and $0.4 million for the pension and other postretirement benefit plans, respectively.

9. Related Party Transactions

Affiliate Entity Transactions

We own a 50% interest in a crude oil pipeline company and are paid a management fee for its operation. During each of 2006, 2007 and 2008 we received operating fees from this company of $0.7 million, which we reported as affiliate management fee revenue.

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

	Year Ended December 31,		
	2006	2007	2008
MGG GP—allocated operating expenses	$73,920	$81,184	$84,460
MGG GP—allocated G&A expenses	40,830	45,300	47,658
MGG MH—allocated G&A expenses	3,000	2,149	440

Under our services agreement with MGG GP, we reimburse MGG GP for costs of employees necessary to conduct our operations. The current affiliate payroll and benefits accruals associated with this agreement at

December 31, 2007 and 2008 were $23.4 million and $18.1 million, respectively, and the long-term affiliate pension and benefits accruals associated with this agreement at December 31, 2007 and 2008 were $22.4 million and $31.8 million, respectively. We settle our affiliate payroll, payroll-related expenses and non-pension postretirement benefit costs with MGG GP on a monthly basis. We settle our long-term affiliate pension liabilities through payments to MGG GP when MGG GP makes contributions to its pension funds.

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 by MGG to us under this agreement was $1.7 million, $4.1 million and $1.6 million in 2006, 2007 and 2008, respectively. We will not receive reimbursements under this agreement beyond 2008.

A former executive officer of our general partner had an investment in MGG MH, an affiliate that, until December 2008, indirectly owned a portion of our general partner. This former executive officer left the company during the fourth quarter of 2006 and we recognized $3.0 million of G&A compensation expenses associated with certain distribution payments made by MGG MH to this individual, with a corresponding increase in partners' capital. During 2007 and 2008, we recognized $2.1 million and $0.4 million, respectively, of G&A compensation expense, with a corresponding increase in partners' capital, for payments made by MGG MH to one of our current executive officers.

Other Related Party Transactions

Until December 2008, MGG, which owns our general partner, was partially owned by MGG MH, which is partially owned by an affiliate of Carlyle/Riverstone Global Energy and Power Fund II, L.P. ("CRF"). During 2006 and the period of January 1 through January 30, 2007, one or more of the members of our general partner's eight-member board of directors was a representative of CRF. At that time, CRF was part of an investment group that purchased Knight, Inc. (formerly known as Kinder Morgan, Inc.). To alleviate competitive concerns the Federal Trade Commission ("FTC") raised regarding this transaction, CRF agreed with the FTC to permanently remove their representatives from our general partner's board of directors, and all of the representatives of CRF voluntarily resigned from the board of directors of our general partner by January 30, 2007.

During 2006 and the period January 1 through January 30, 2007, CRF had total combined general and limited partner interests in SemGroup, L.P. ("SemGroup") of approximately 30%. During the aforementioned time periods, one of the members of the seven-member board of directors of SemGroup's general partner was a representative of CRF, with three votes on that board. We were a party to a number of arms-length transactions with SemGroup and its affiliates, which we had historically disclosed as related party transactions. For accounting purposes, we have not classified SemGroup as a related party since the voluntary resignation of the CRF representatives from our general partner's board of directors as of January 30, 2007. A summary of our transactions with SemGroup during 2006 and the period of January 1 through January 30, 2007 is provided in the following table (in millions):

	Year Ended December 31, 2006	Period From January 1, 2007 Through January 30, 2007
Product sales revenues	$177.1	$20.5
Product purchases	$ 63.2	$14.5
Terminalling and other services revenues	$ 4.4	$ 0.3
Storage tank lease revenues	$ 3.4	$ 0.4
Storage tank lease expense	$ 1.0	$ 0.1

In addition to the above, we provided common carrier transportation services to SemGroup.

One of our general partner's former independent board members, John P. DesBarres, served as a board member for American Electric Power Company, Inc. ("AEP") of Columbus, Ohio until December 2008. Mr. DesBarres passed away on December 29, 2008. For the years ended December 31, 2006, 2007 and 2008, our operating expenses included $2.9 million, $2.7 million and $2.8 million, respectively, of power costs incurred with Public Service Company of Oklahoma ("PSO"), which is a subsidiary of AEP. We had no amounts payable to or receivable from PSO or AEP at December 31, 2007 or December 29, 2008.

Because our distributions have exceeded target levels as specified in our partnership agreement, our general partner receives approximately 50% of any incremental cash distributed per limited partner unit. As of December 31, 2008, our executive officers collectively owned a beneficial interest of approximately 1% of MGG, the owner of our general partner. Therefore, our executive officers indirectly benefit from distributions paid to our general partner. In 2006, 2007 and 2008, distributions paid to our general partner, based on its general partner interest and incentive distribution rights, totaled $56.3 million, $70.3 million and $85.6 million, respectively.

In connection with the closing of an equity offering completed by MGG in February 2006, we amended our partnership agreement to remove the requirement for our general partner to maintain its 2% interest in any future offering of our limited partner units. In addition, we amended our partnership agreement to restore the incentive distribution rights to the same level as before an amendment made in connection with our October 2004 pipeline system acquisition, which reduced the incentive distributions paid to our general partner by $1.3 million for 2004, $5.0 million for 2005 and $3.0 million for 2006. In return, MGG made a capital contribution to us on February 9, 2006 equal to the present value of the remaining reductions in incentive distributions, or $4.2 million. In January 2007, we issued 185,673 limited partner units primarily to settle the 2004 unit award grants to certain employees, which vested on December 31, 2006. Our general partner did not make an equity contribution associated with this equity issuance and as a result its general partner ownership interest in us changed from 2.000% to 1.995%. In January 2008, we issued 197,433 limited partner units primarily to settle the 2005 unit award grants to certain employees, which vested on December 31, 2007. Our general partner did not make an equity contribution associated with this equity issuance and as a result its general partner ownership interest in us changed from 1.995% to 1.989%. See Note 22—Subsequent Events, for a discussion of equity issuances and changes in our general partner's ownership interest that occurred after year-end.

10. Debt

Our debt at December 31, 2007 and 2008 was as follows (in thousands):

	December 31,	
	2007	**2008**
Revolving credit facility	$163,500	$ 70,000
6.45% Notes due 2014	249,634	249,681
5.65% Notes due 2016	252,494	253,328
6.40% Notes due 2018	—	261,555
6.40% Notes due 2037	248,908	248,921
Total debt	$914,536	$1,083,485

The face value of our debt outstanding as of December 31, 2008 was $1,070.0 million. The difference between the face value and carrying value of our debt outstanding was amounts recognized for discounts incurred on debt issuances and the unamortized portion of gains recognized on derivative financial instruments which had qualified as fair value hedges of our long-term debt until the hedges were terminated or hedge accounting treatment was discontinued. At December 31, 2008, maturities of our debt were as follows: $0 in 2009, 2010 and 2011; $70.0 million in 2012; $0 in 2013; and $1.0 billion thereafter. Our debt is non-recourse to our general partner.

Revolving Credit Facility. In September 2007, we amended and restated our revolving credit facility to increase the borrowing capacity from $400.0 million to $550.0 million. In addition, the maturity date of the revolving credit facility was extended from May 2011 to September 2012. We incurred $0.2 million of legal and other costs associated with this amendment. Borrowings under the facility remain unsecured and incur interest at LIBOR plus a spread that ranges from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. Borrowings under this facility are used primarily for general purposes, including capital expenditures. As of December 31, 2008, $70.0 million was outstanding under this facility and $3.9 million was obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets. The weighted-average interest rate on borrowings outstanding under the facility at December 31, 2007 and 2008 was 5.4% and 4.8%, respectively. Additionally, a commitment fee is assessed at a rate from 0.05% to 0.125%, depending on our credit rating. Borrowings outstanding under this facility as of July 14, 2008 of $212.0 million were repaid with the net proceeds from our debt offering of 10-year senior notes completed in July 2008 (see *6.40% Notes due 2018* below).

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, and the discount is being accreted over the life of the notes. Including the impact of amortizing the gains realized on the hedges associated with these notes (see Note 11—Derivative Financial Instruments), 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% senior notes due 2016 in an underwritten public offering. The notes were issued for the discounted price of 99.9%, or $249.7 million, and the discount is being accreted over the life of the notes. We used an interest rate swap to effectively convert $100.0 million of these notes to floating-rate debt until May 2008 (see Note 11—Derivative Financial Instruments). Including the amortization of the $3.8 million gain realized from terminating that interest rate swap and the amortization of losses realized on pre-issuance hedges associated with these notes, the weighted-average interest rate of these notes at December 31, 2007 and 2008 was 5.5% and 5.7%, respectively. The outstanding principal amount of the notes was increased by $2.7 million at December 31, 2007 for the fair value of the associated swap-to-floating derivative instrument and by $3.5 million at December 31, 2008 for the unamortized portion of the gain recognized upon termination of that swap.

6.40% Notes due 2018. In July 2008, we issued $250.0 million of 6.40% notes due 2018 in an underwritten public offering. Net proceeds from the offering, after underwriter discounts of $1.6 million and offering costs of $0.4 million, were $248.0 million. The net proceeds were used to repay the $212.0 million of borrowings outstanding under our revolving credit facility at that time, and the balance was used for general purposes. In connection with this offering, we entered into $100.0 million of interest rate swap agreements to hedge against changes in the fair value of a portion of these notes, effectively converting $100.0 million of these notes to floating-rate debt (see Note 11—Derivative Financial Instruments). These agreements originally expired on July 15, 2018, the maturity date of the 6.40% notes; however, in December 2008 we terminated $50.0 million of these agreements and discontinued hedge accounting on the remaining $50.0 million, resulting in our recognizing gains of $11.7 million. The outstanding principal amount of the notes was increased by $11.7 million at December 31, 2008 for the unamortized portion of those gains. Including the amortization of those gains, the weighted-average interest rate of these notes at December 31, 2008 was 5.9%.

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, and the discount is being accreted over the life of the notes. Net proceeds from the offering, after underwriter discounts of $2.2 million and offering costs of $0.3 million, were $246.4 million. The net proceeds were used to repay a portion of other notes that were outstanding at that time. Including the impact of amortizing the gains realized on the interest hedges associated with these notes (see Note 11—Derivative Financial Instruments), the effective interest rate of these notes is 6.3%.

The revolving credit facility described above requires us to maintain a specified ratio of consolidated debt to EBITDA 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, 2008.

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

During the years ending December 31, 2006, 2007 and 2008, total cash payments for interest on all indebtedness, including the impact of related interest rate swap agreements, net of amounts capitalized, were $57.2 million, $59.2 million and $49.3 million, respectively.

11. 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 forward sales agreements to lock in forward sales prices and most of the gross margins realized from our blending activities. We account for these forward sales agreements as normal sales.

In addition to forward sales agreements, we use NYMEX contracts to lock in forward sales prices. Although these NYMEX agreements represent an economic hedge against price changes on the petroleum products we expect to sell in the future, they do not qualify as normal purchases or for hedge accounting treatment under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities (as amended)*; therefore, we recognize the change in fair value of these agreements currently in earnings. During 2008, we closed our positions on NYMEX contracts associated with the sale of 0.5 million barrels of gasoline, and recognized total gains of $30.7 million as product sales revenues. At December 31, 2008, the fair value of our open NYMEX contracts, representing 0.6 million barrels of petroleum product, was a gain of $20.2 million, which we recognized as energy commodity derivative contracts on our consolidated balance sheet. These open NYMEX contracts mature between January 2009 and April 2009. At December 31, 2008, we had received $19.0 million in margin cash from these agreements, which we recorded as energy commodity derivatives deposit on our consolidated balance sheet.

Interest Rate Derivatives

We use interest rate derivatives to help manage interest rate risk. As of December 31, 2008, we had two offsetting interest rate swap agreements outstanding:

- 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% and terminates in July 2018. We originally accounted for Derivative A as a fair value hedge. On December 8, 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 on Derivative A. The $5.4 million fair value of Derivative A at that time was recorded as an adjustment to long-term debt and is being amortized over the remaining life of the 6.40% fixed-rate notes due 2018. The fair value of Derivative A as of December 31, 2008 was $7.5 million, of which $0.3 million was recorded to other current assets and $7.2 million was recorded to noncurrent assets on our consolidated balance sheet. The change in fair value of Derivative A from the date we discontinued hedge accounting, until December 31, 2008, was a gain of $1.9 million, which was recorded to other (income) expense on our consolidated statement of income.

- In December 2008, concurrent with the discontinuance of hedge accounting treatment of Derivative A described above, we entered into an offsetting $50.0 million interest rate swap agreement with a different financial institution pursuant to which we pay a fixed rate of 6.40% and receive a floating rate of six-month LIBOR plus 3.23%. This agreement terminates in July 2018. We entered into this agreement to offset changes in the fair value of Derivative A, excluding changes due to changes in counterparty credit risks. We did not designate this agreement as a hedge for accounting purposes. The fair value of this agreement as of December 31, 2008 was $(1.8) million, which was recorded to other deferred liabilities on our consolidated balance sheet and other (income) expense on our consolidated statement of income.

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. As of December 31, 2006, we had recorded a $0.2 million gain associated with these agreements to other comprehensive income. 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 our 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 following is a summary of the current impact of our historical derivative activity on accumulated other comprehensive income (“AOCI”) for the years ended December 31, 2007 and 2008 (in thousands):

		Effective Portion of Gains			
		2007		2008	
Hedge	**Total Gain (Loss) Realized on Settlement of Hedge**	**Unamortized Amount Recognized in AOCI**	**Amount Reclassified to Earnings from AOCI**	**Unamortized Amount Recognized in AOCI**	**Amount Reclassified to Earnings from AOCI**
Cash flow hedges (date executed):					
Interest rate swaps 6.40% Notes (April 2007)	$ 5,255	$ 5,132	$(123)	$ 4,957	$(175)
Interest rate swaps 5.65% Notes (October 2004)	(6,279)	(4,600)	524	(4,077)	523
Interest rate swaps and treasury lock 6.45% Notes (May 2004)	5,119	3,285	(512)	2,773	(512)
Interest rate hedge pipeline notes (October 2002)	(995)	—	174	—	—
Total cash flow hedges		$ 3,817	$ 63	$ 3,653	$(164)

There was no ineffectiveness recognized on the financial instruments disclosed in the above tables during the years ended December 31, 2007 and 2008.

12. Leases

Leases—Lessee

We lease land, office buildings, tanks and terminal equipment at various locations to conduct our business operations. Several of the agreements provide for negotiated renewal options and cancellation penalties, some of which include the requirement to remove our pipeline from the property for non-performance. Management expects that 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 SFAS No. 13, *Accounting for Leases*. Rent expense is recognized on a straight-line basis over the life of the lease. Total rent expense was \$6.3 million, \$4.6 million and \$4.6 million for the years ended December 31, 2006, 2007 and 2008, respectively. Future minimum annual rentals under non-cancelable operating leases as of December 31, 2008, were as follows (in thousands):

2009	\$ 3,393
2010	3,379
2011	3,167
2012	2,427
2013	1,476
Thereafter	8,121
Total	\$21,963

Leases—Lessor

We have entered into capacity and storage leases with remaining terms from one to 10 years that we account for as operating-type leases. All of the agreements provide for negotiated extensions. Future minimum lease payments receivable under operating-type leasing arrangements as of December 31, 2008, were as follows (in thousands):

2009	\$115,465
2010	96,147
2011	77,969
2012	58,667
2013	33,500
Thereafter	58,764
Total	\$440,512

In December 2001, we 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. We then entered into a long-term lease arrangement under which Aux Sable is the sole lessee of these assets. We have accounted for this transaction as a direct financing lease. The lease expires in December 2016 and has a purchase option after the first year. Aux Sable has the right to re-acquire the pipeline at the end of the lease for a de minimus amount. Future minimum lease payments receivable under this direct-financing leasing arrangement as of December 31, 2008 were \$1.3 million each year in 2009, 2010, 2011, 2012 and 2013 and \$3.7 million cumulatively for all periods after 2013. The net investment under direct financing lease arrangements as of December 31, 2007 and 2008 was as follows (in thousands):

	December 31,	
	2007	2008
Total minimum lease payments receivable	\$11,514	\$10,234
Less: Unearned income	4,487	3,664
Recorded net investment in direct financing leases	\$ 7,027	\$ 6,570

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

	December 31,	
	2007	2008
Classification of direct financing leases:		
Current accounts receivable	$ 563	$ 622
Noncurrent accounts receivable	6,464	5,948
Total	$7,027	$6,570

13. Long-Term Incentive Plan

Plan Description

We have a long-term incentive plan ("LTIP") for certain MGG GP employees who perform services for us 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 limited partner units. The remaining units available under the LTIP at December 31, 2008 total 1.7 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	Units Paid Out on Vesting Date	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

In January 2007, we settled the February 2004 award grants by issuing 184,905 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. We paid associated tax withholdings and employer taxes totaling $4.4 million in January 2007.

In January 2008, we settled the cumulative amounts of the February 2005 and June 2006 award grants 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. We paid associated tax withholdings and employer taxes totaling $5.1 million in January 2008.

In January 2009, we settled the cumulative amounts of the remaining 2006 and March 2007 award grants by issuing 209,321 limited partner units and distributing those units to the participants (see Note 22—Subsequent Events). There was no impact on our 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. We paid associated tax withholdings and employer taxes totaling $4.0 million in January 2009.

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 common limited partner units in us. 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, MGG purchased its general partner from MGG MH. When this transaction closed, a change in control occurred as defined in our LTIP. 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 December 3, 2008 in order to receive enhanced LTIP payouts.

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 was accounted for as liabilities. For example, if a LTIP participant received an award of 100 units and at the end of the vesting period the payout for that award grant was at stretch performance, the recipient would receive a minimum of 160 units for the 80% portion of the payout based solely on the attainment of financial metrics (100 unit award x 80% x 200% payout for stretch financial performance). The remainder of the award would be subject to the financial metrics performance results resulting in an additional 40 unit payout (100 unit award x 20% x 200% payout for stretch financial performance); however, the Compensation Committee, at its discretion, can change the payout of this portion of the award from a payout of zero units up to 80 units. Therefore, the original 100 unit award payout, at stretch financial performance, would range from a minimum of 160 units to a maximum of 240 units.

The table below summarizes the performance based unit awards granted by the Compensation Committee that have not yet vested as of December 31, 2008. There was no impact to our 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, 2008 (Millions)
January 2007 Awards:							
Tranche 1: January 2007	53,230	2,396	50,835	101,669	12/31/09	$ 1.1	$ 3.1
Tranche 2: January 2008	53,230	2,396	(39,803)	11,031	12/31/09	0.2	0.3
Tranche 3:(2)	—	—	—	—	12/31/09	—	—
January 2008	184,340	8,295	(123,231)	52,814	12/31/10	1.1	1.6
Various 2008	5,492	248	(3,672)	1,572	12/31/10	*	*
Total	296,292	13,335	(115,871)	167,086		$ 2.4	$ 5.0

(1) Unrecognized compensation expense will be recognized over the remaining vesting periods of the awards.
(2) The grant date for this tranche has not yet been set. Because this table reflects unvested unit awards at December 31, 2008, quantities associated with this tranche have not been included. There were 53,230 unit awards approved under this tranche.

* Values are less than $0.1 million.

The unit awards approved during 2007 are broken into three equal tranches, with each tranche vesting on December 31, 2009. We began accruing for Tranche 1 in the first quarter of 2007 and Tranche 2 in the first quarter of 2008, when the Compensation Committee established the financial metric associated with each respective tranche. We will begin accruing costs for Tranche 3 when the Compensation Committee establishes the associated financial metric for that tranche. The unit awards allocated to each tranche are expensed over their respective vesting periods. As of December 31, 2008, the accrual for payout of Tranche 1 was 200%, as the related financial metric for the year ended December 31, 2007 was above the stretch target. The accrual for payout of Tranche 2 was 22%, as the related financial metric was slightly above the threshold target.

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, 2008 (Millions)
Various 2008	9,248	286	8,962	12/31/10	$0.2	$0.3
Various 2008	40,315	1,814	38,501	12/31/11	0.8	1.2
	49,563	2,100	47,463		$1.0	$1.5

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

Fair Value of Unit Awards

	2006 Awards	2007 Awards	2008 Awards
Weighted-average per unit grant date fair value of equity awards(a)	$25.24	$33.05	$28.61
December 31, 2008 per unit fair value of liability awards(b)	$30.21	$27.30	$24.27

(a) Approximately 80% of the unit awards are accounted for as equity (see *Plan Description* 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 *Plan Description* 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 the directors of our general partner, for 2006, 2007 and 2008 was as follows (in thousands):

	Year Ended December 31, 2006		
	Equity Method	Liability Method	Total
2003 awards	$ —	$ (89)	$ (89)
2004 awards	—	4,355	4,355
2005 awards	—	4,096	4,096
2006 awards	1,771	687	2,458
Total	$1,771	$9,049	$10,820

	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	639	82	721
Total	$4,138	$ 613	$4,751

Long-term incentive awards were also granted to independent members of the board of directors of our general partner pursuant to the LTIP. Beginning in 2007, our independent directors could elect to defer all or a portion of payment of their compensation. All compensation amounts deferred are credited to the applicable director's account in the form of phantom limited partner units, with distribution equivalent rights. Phantom 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,		
	2006	2007	2008
Phantom units earned	1,459	5,217	6,898
Compensation expense recognized	$ 50	$ 221	$ 263

14. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. Our segments are managed separately because each requires different marketing strategies and business knowledge. Management evaluates performance based on segment operating margin, which includes revenues from affiliates and external customers, operating expenses, product purchases and equity earnings. Transactions between our business segments are conducted and recorded on the same basis as transactions with third-party entities.

We believe that investors benefit from having access to the same financial measures being used by management. Operating margin, which is presented in the tables below, is an important measure used by management to evaluate the economic performance of our core operations. This measure forms the basis of our internal financial reporting and is used by management in deciding how to allocate capital resources between segments. 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 below. Operating profit includes expense items, such as depreciation and amortization and affiliate G&A expenses, that management does not consider when evaluating the core profitability of our operations.

Beginning in 2007, commercial and operating responsibilities for our two inland terminals in the Dallas, Texas area were transferred from the petroleum products terminals segment to our petroleum products pipeline system segment. The primary reasons for these transfers were because of location and operating synergies. Prior to the transfers, our customers were required to work with our different entities in order to do business at these facilities. Additionally, we were engaged in two distinct marketing strategies, one for terminalling services and one for pipeline transportation services. Since the beginning of 2007, these facilities have been under petroleum products pipeline management and their operating results have been reported both internally and externally as part of that segment. Historical financial results for our operating segments have been adjusted to reflect the impact of this transfer. Consolidated segment profit did not change as a result of these historical reclassifications.

	Year Ended December 31, 2006				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
			(in thousands)		
Transportation and terminals revenues	$ 419,263	$125,962	$16,473	$(3,397)	$ 558,301
Product sales revenues	649,172	15,397	—	—	664,569
Affiliate management fee revenue	690	—	—	—	690
Total revenues	1,069,125	141,359	16,473	(3,397)	1,223,560
Operating expenses	189,684	47,376	13,932	(6,466)	244,526
Product purchases	598,575	7,280	—	(514)	605,341
Equity earnings	(3,324)	—	—	—	(3,324)
Operating margin	284,190	86,703	2,541	3,583	377,017
Depreciation and amortization expense	38,512	17,980	777	3,583	60,852
Affiliate G&A expenses	45,980	18,926	2,206	—	67,112
Operating profit (loss)	$ 199,698	$ 49,797	$ (442)	$ —	$ 249,053
Segment assets	$1,338,715	$560,993	$23,659	$ —	$1,923,367
Corporate assets					29,282
Total assets					$1,952,649
Goodwill	$ —	$ 23,945	$ —	$ —	$ 23,945
Additions to long-lived assets	$ 79,914	$ 80,143	$ 641	$ —	$ 160,698
Equity investments	$ 24,087	$ —	$ —	$ —	$ 24,087

	Year Ended December 31, 2007				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
			(in thousands)		
Transportation and terminals revenues	$ 459,772	$132,693	$18,287	$(2,907)	$ 607,845
Product sales revenues	692,355	17,209	—	—	709,564
Affiliate management fee revenue	712	—	—	—	712
Total revenues	1,152,839	149,902	18,287	(2,907)	1,318,121
Operating expenses	179,426	56,301	21,295	(5,421)	251,601
Product purchases	626,194	8,233	—	(518)	633,909
Equity earnings	(4,027)	—	—	—	(4,027)
Operating margin (loss)	351,246	85,368	(3,008)	3,032	436,638
Depreciation and amortization expense	39,658	20,315	787	3,032	63,792
Affiliate G&A expenses	52,198	17,756	2,633	—	72,587
Operating profit (loss)	$ 259,390	$ 47,297	$ (6,428)	$ —	$ 300,259
Segment assets	$1,431,069	$614,409	$25,911	$ —	$2,071,389
Corporate assets					29,805
Total assets					$2,101,194
Goodwill	$ —	$ 23,945	$ —	$ —	$ 23,945
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	$ 477,621	$141,129	$22,704	$(3,496)	$ 637,958
Product sales revenues	543,694	30,401	—	—	574,095
Affiliate management fee revenue	733	—	—	—	733
Total revenues	1,022,048	171,530	22,704	(3,496)	1,212,786
Operating expenses	198,356	59,284	14,061	(5,973)	265,728
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	424,957	103,967	8,643	3,483	541,050
Depreciation and amortization expense	42,571	24,236	863	3,483	71,153
Affiliate G&A expenses	50,580	16,797	3,058	—	70,435
Operating profit	$ 331,806	$ 62,934	$ 4,722	$ —	$ 399,462
Segment assets	$1,465,242	$734,485	$32,335	$ —	$2,232,062
Corporate assets					64,053
Total assets					$2,296,115
Goodwill	$ 2,864	$ 23,945	$ —	$ —	$ 26,809
Additions to long-lived assets	$ 156,266	$144,620	$ 5,536	$ —	$ 306,422
Equity investments	$ 23,190	$ —	$ —	$ —	$ 23,190

15. Commitments and Contingencies

Environmental Liabilities. Liabilities recognized for estimated environmental costs were $57.8 million and $41.8 million at December 31, 2007 and 2008, 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. Environmental expenses recognized as a result of changes in our environmental liabilities are included in operating expenses on our consolidated statements of income. Environmental expense was $12.4 million, $10.0 million and $(1.4) million in 2006, 2007 and 2008, respectively. See *Indemnification Settlement* below for a discussion of a settlement which significantly reduced environmental expense in 2008.

Our environmental liabilities included, among other items, accruals for the items discussed below:

Petroleum Products EPA Issue. In July 2001, the Environmental Protection Agency ("EPA"), pursuant to Section 308 of the Clean Water Act (the "Act"), served an information request to a former affiliate with regard to petroleum discharges from its pipeline operations. That inquiry primarily focused on the petroleum products pipeline system that we subsequently acquired. The EPA added to their original demand two subsequent releases that occurred from our petroleum products pipeline system. In September 2008, we paid a penalty of $5.3 million and agreed to perform certain operational enhancements under the terms of a settlement agreement reached with the EPA and Department of Justice ("DOJ"). This agreement led to a reduction of our environmental liability for these matters from $17.4 million to $5.3 million and a reduction of our operating expenses of $12.1 million during second quarter 2008. Of this reduction, $11.9 million was included as part of the indemnification settlement we reached with a former affiliate and, accordingly, was allocated to our general partner.

Ammonia EPA Issue. In February 2007, 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 Act with respect to two releases of anhydrous ammonia from the ammonia pipeline owned by us and, at the time of the releases, operated by a third party. The DOJ stated that the maximum statutory penalty for alleged violations of the Act for both releases combined was approximately $13.2 million. The DOJ also alleged that the third-party operator of our ammonia pipeline was liable for penalties pursuant to Section 103 of the Comprehensive Environmental Response, Compensation and Liability Act for failure to report the releases on a timely basis, with the statutory maximum for those penalties as high as $4.2 million for which the third-party operator has requested indemnification. In March 2007, we also received a demand from the third-party operator for defense and indemnification in regards to a DOJ criminal investigation regarding whether certain actions or omissions of the third-party operator constituted violations of federal criminal statutes. The third-party operator has subsequently settled this criminal investigation with the DOJ by paying a $1.0 million fine. We believe that we do not have an obligation to indemnify or defend the third-party operator for the DOJ criminal fine settlement. The DOJ stated in its notice to us that it does not expect us or the third-party operator to pay the penalties at the statutory maximum; however, it may seek injunctive relief if the parties cannot agree on any necessary corrective actions. We have accrued an amount for these matters based on our best estimates that is less than the maximum statutory penalties. We are currently in discussions with the EPA, DOJ and the third-party operator regarding these two releases; however, we are unable to determine what our ultimate liability could be for these matters. Adjustments to our recorded liability, which could occur in the near term, could be material to our results of operations and cash flows.

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 these indemnification obligations. We received the final two installment payments of $35.0 million and $20.0 million associated with this agreement in 2007 and

2006, respectively. At December 31, 2007 and 2008, known liabilities that would have been covered by this indemnity agreement were estimated to be $42.9 million and $25.5 million, respectively. Through December 31, 2008, we have spent $59.0 million of the indemnification settlement proceeds for indemnified matters, including $23.1 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.

Environmental Receivables. Receivables from insurance carriers and other entities related to environmental matters were $6.9 million and $4.5 million at December 31, 2007 and 2008, 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 $2.4 million as of December 31, 2008. 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.

16. Quarterly Financial Data (unaudited)

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

2007	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$291,987	$328,155	$321,957	$376,022
Operating margin	97,795	112,646	104,680	121,517
Total costs and expenses	228,080	250,051	251,501	292,257
Net income	49,702	61,452	59,444	72,192
Basic net income per limited partner unit	0.55	0.66	0.65	0.75
Diluted net income per limited partner unit	0.55	0.66	0.65	0.74
2008				
Revenues	$346,493	$272,914	$291,980	$301,399
Operating margin	140,230	142,034	122,293	136,493
Total costs and expenses	268,116	168,145	206,286	201,336
Net income	93,322	94,374	73,336	85,581
Basic net income per limited partner unit	0.89	0.80	0.75	0.83
Diluted net income per limited partner unit	0.89	0.80	0.75	0.83

First-quarter 2008 net income was favorably impacted by the $26.5 million gain recognized from our assignment of a supply agreement. Second-quarter 2008 net income was favorably impacted by a $12.1 million reduction in our operating expenses when we settled an environmental matter for less than amounts we had 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.

Second-quarter 2007 net income was negatively impacted by $2.9 million of expenses associated with the repayment of our pipeline notes. Fourth-quarter 2007 revenues and net income were favorably impacted by $2.8 million of revenues recognized from our variable-rate terminalling agreements.

17. 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 derivative contracts. The carrying amount reported in the balance sheet represents fair value (see Note 11—Derivative Financial Instruments).

Long-term receivables. Fair value was determined by discounting estimated future cash flows by the rates inherent in the long-term instruments adjusted for the change in the risk-free rate since inception of the instrument.

Energy commodity derivatives deposit. This liability represents a short-term deposit we held associated with our energy commodity derivative contracts. The carrying amount reported in the balance sheet approximates fair value due to the short-term maturity of the underlying contracts.

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, 2007 and 2008. The carrying amount of borrowings under our revolving credit facility at December 31, 2007 and 2008 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 year end, in an orderly transaction with the financial institution counterparties of the interest rate derivative agreements.

Other deferred liabilities—deposits. This liability represented a long-term deposit we held associated with a supply agreement which was assigned to a third party in March 2008. Fair value was determined by discounting the deposit amount at our incremental borrowing rate.

The following table reflects the carrying amounts and fair values of our financial instruments as of December 31, 2007 and 2008 (in thousands):

	December 31, 2007		December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ —	$ —	$ 33,241	$ 33,241
Energy commodity derivative contracts	—	—	20,200	20,200
Long-term receivables	7,506	6,849	7,119	5,249
Energy commodity derivatives deposit	—	—	18,994	18,994
Debt	911,801	933,650	1,083,485	934,975
Interest rate swaps:				
$100.0 million (October 2004)	2,735	2,735	—	—
$50.0 million (July 2008)	—	—	7,542	7,542
$50.0 million (December 2008)	—	—	(1,770)	(1,770)
Other deferred liabilities—deposits	18,500	9,886	—	—

Fair Value Measurements

The following table summarizes the fair value measurements of our energy commodity derivative contracts and interest rate swap agreements as of December 31, 2008, based on the three levels established by SFAS No. 157, *Fair Value Measurements* (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:				
$50.0 million (July 2008)	7,542	—	7,542	—
$50.0 million (December 2008)	(1,770)	—	(1,770)	—

Our fair value measurements as of December 31, 2007 using significant other observable inputs for interest rate swap derivatives were $2.7 million.

18. Distributions

We paid the following distributions during 2006, 2007 and 2008 (in thousands, except per unit amounts):

Date Cash Distribution Paid	Per Unit Cash Distribution Amount	Common Units	Subordinated Units	General Partner[(a)]	Total Cash Distribution
02/14/06	$0.55250	$ 33,526	$3,138	$12,839	$ 49,503
05/15/06	0.56500	37,494	—	13,668	51,162
08/14/06	0.57750	38,324	—	14,497	52,821
11/14/06	0.59000	39,153	—	15,327	54,480
Total	$2.28500	$148,497	$3,138	$56,331	$207,966
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

(a) Includes amounts paid to our general partner for its incentive distribution rights.

In February 2006, we amended our partnership agreement to restore the incentive distribution rights to the same level as before an amendment made in connection with our October 2004 pipeline system acquisition that reduced the incentive distributions paid to our general partner by $1.3 million for 2004, $5.0 million for 2005 and $3.0 million for 2006. In return, MGG made a capital contribution to us on February 9, 2006 equal to the present value of the remaining reductions in incentive distributions, or $4.2 million.

On February 13, 2009, 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 6, 2009. Because we issued 210,149 limited partner units in January 2009 and our general partner did not make an equity contribution to us associated with that equity issuance, our general partner's ownership interest in us changed from 1.989% to 1.983%. See Note 22—Subsequent Events for further discussion of this matter. The total distributions paid on February 13, 2009 were $71.0 million, of which $1.4 million was paid to our general partner on its 1.983% general partner interest and $22.1 million on its incentive distribution rights.

19. Net Income Per Unit

The following table provides details of the basic and diluted net income per unit computations (in thousands, except per unit amounts):

	For The Year Ended December 31, 2006		
	Income (Numerator)	Units (Denominator)	Per Unit Amount
Limited partners' interest in income	$148,881		
Basic net income per limited partner unit	$148,881	66,361	$ 2.24
Effect of dilutive restrictive unit grants	—	252	—
Diluted net income per limited partner unit	$148,881	66,613	$ 2.24

	For The Year Ended December 31, 2007		
	Income (Numerator)	Units (Denominator)	Per Unit Amount
Limited partners' interest in income	$173,330		
Basic net income per limited partner unit	$173,330	66,547	$ 2.60
Effect of dilutive restrictive unit grants	—	153	—
Diluted net income per limited partner unit	$173,330	66,700	$ 2.60

	For The Year Ended December 31, 2008		
	Income (Numerator)	Units (Denominator)	Per Unit Amount
Limited partners' interest in income	$219,136		
Basic net income per limited partner unit	$219,136	66,855	$ 3.28
Effect of dilutive restrictive unit grants	—	72	(0.01)
Diluted net income per limited partner unit	$219,136	66,927	$ 3.27

Units reported as dilutive securities are related to restricted unit grants associated with unvested awards (see Note 13—Long-Term Incentive Plan).

20. Partners' Capital

Units outstanding. The following table details the changes in the number of our units outstanding from January 1, 2006 through December 31, 2008.

	Common	Subordinated	Total
Units outstanding on January 1, 2006	60,680,928	5,679,696	66,360,624
01/06—Conversion of subordinated units to common units[a]	5,679,696	(5,679,696)	—
Units outstanding on December 31, 2006	66,360,624	—	66,360,624
01/07—Settlement of 2004 award grants	184,905	—	184,905
Other[c]	768	—	768
Units outstanding on December 31, 2007[b]	66,546,297	—	66,546,297
01/08—Settlement of 2005 award grants	196,856	—	196,856
Other[c]	577	—	577
Units outstanding on December 31, 2008[b]	66,743,730	—	66,743,730

(a) Our subordination period ended on December 31, 2005 when we met the final financial tests provided for in our partnership agreement. As a result, on January 31, 2006, one day following the distribution record date, the 5,679,696 outstanding subordinated units representing limited partner interests in us converted to common units.

(b) For the years ended December 31, 2007 and 2008, the weighted-average number of limited partner units outstanding for basic net income per unit calculation includes phantom limited partner units associated with deferred compensation of certain directors of our general partner.

(c) Common units issued to settle the equity-based retainer paid to one of the independent directors of our general partner.

Limited partners holding our common 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 66.7% majority 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.

From January 24, 2008 until January 23, 2009, cash distributions to our general partner and limited partners were made based on the following table:

	Percentage of Distributions		
		General Partner	
Quarterly Distribution Amount per Unit	Limited Partners	General Partner Interest	Incentive Distribution Rights
Up to $0.289	98.011%	1.989%	0.000%
Above $0.289 up to $0.328	85.011%	1.989%	13.000%
Above $0.328 up to $0.394	75.011%	1.989%	23.000%
Above $0.394	50.011%	1.989%	48.000%

See Note 22—Subsequent Events for a discussion of the changes in the percentage of distributions to the limited and general partner interests that occurred after December 31, 2008.

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.

Unit purchase rights plan. In December 2008, the board of directors of our general partner adopted a unit purchase rights plan. Under our unit purchase rights plan, each of our outstanding common units carries the right to purchase one additional common unit at a price of $145, subject to adjustment. Generally, the rights become exercisable only in certain circumstances in which a person or group acquires, or attempts to acquire, 15% or more of our common units without the consent of our general partner's board of directors. When exercisable, each right would then entitle the holder of the right (other than the person or group making the acquisition) to purchase, for the then current purchase price of the right, our common units, or shares of stock or common units of any person into which we are thereafter merged or to which 50% or more of our assets or earning power is sold, with a market value of twice the purchase price of the right. The rights will expire on December 3, 2011, unless extended or earlier redeemed. Under certain circumstances, the board of directors of our general partner may redeem the rights for $0.001 per right.

Other changes in capital. Capital contributions were $28.7 million, $40.2 million and $3.3 million during 2006, 2007 and 2008, respectively. Capital contributions for 2006 and 2007 included payments of $20.0 million and $35.0 million, respectively, we received under the May 2004 indemnity settlement. 2006 capital contributions included a $4.2 million payment made by MGG to us related to an amendment of our partnership agreement to restore the incentive distributions to the same level as before an amendment made in connection with a 2004 acquisition which reduced the incentive distributions paid to our general partner in 2004, 2005 and 2006 (see Note 9—Related Party Transactions). The remaining capital contributions are primarily from amounts we received from MGG under the G&A cost cap agreement.

21. Assignment of Supply Agreement

As part of our acquisition of a pipeline system in October 2004, we assumed a third-party supply agreement. Under this agreement, we were obligated to supply petroleum products to one of our customers until 2018. At the time of this acquisition, we believed that the profits we would receive from the supply agreement were below the fair value of our tariff-based shipments on this pipeline and we established a liability for the expected shortfall. On March 1, 2008, we assigned this supply agreement and sold related inventory of $47.6 million to a third-party entity. Further, we returned our former customer's cash deposit, which was $16.5 million at the time of the assignment. During first quarter 2008, we obtained a full release from the supply customer; therefore, we 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, we wrote off the unamortized amount of the liability and recognized a gain of $26.5 million.

22. Subsequent Events

On January 23, 2009, we issued 210,149 limited partner units, of which 209,321 were issued to settle the cumulative amount of the 2006 and 2007 unit award grants to certain employees that vested on December 31, 2008, and 828 were issued to settle the equity-based retainer paid to one of the directors of our general partner. Our general partner did not make an equity contribution associated with this equity issuance and as a result its general partner ownership interest in us changed from 1.989% to 1.983%. Our general partner's incentive distribution rights were not affected by this transaction. As a result, cash distributions paid after January 23, 2009 will be made based on the following table:

	Percentage of Distributions		
		General Partner	
Quarterly Distribution Amount per Unit	Limited Partners	General Partner Interest	Incentive Distribution Rights
Up to $0.289	98.017%	1.983%	0.000%
Above $0.289 up to $0.328	85.017%	1.983%	13.000%
Above $0.328 up to $0.394	75.017%	1.983%	23.000%
Above $0.394	50.017%	1.983%	48.000%

On February 10, 2009, our Compensation Committee approved 285,000 unit award grants pursuant to the long-term incentive plan. These award grants have a three-year vesting period that will end on December 31, 2011.

On February 13, 2009, 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 6, 2009. The total distributions paid were $71.0 million, of which $1.4 million was paid to our general partner on its approximate 2% general partner interest and $22.1 million on its incentive distribution rights.

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

None.

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

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) 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 has been no change in our internal control over financial reporting (as defined in Rule 13a-15(f) of the Securities Exchange Act) during the quarter ended December 31, 2008 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 control over financial reporting will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that simple errors or mistakes can occur. Additionally, 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 control and make modifications as necessary; our intent in this regard is that the disclosure controls and the internal control will be maintained as systems change and conditions warrant.

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:

- Class I 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 3	
*(a)	Certificate of Limited Partnership of Magellan Midstream Partners, L.P. dated August 30, 2000, as amended on November 15, 2002 and August 12, 2003 (filed as Exhibit 3.1 to Form 10-Q filed November 10, 2003).
*(b)	Fourth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated as of April 13, 2005 (filed as Exhibit 3.1 to Form 8-K filed April 22, 2005).
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*(e)	Amendment No. 3 dated July 27, 2007 to Fourth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated as of April 13, 2005 (filed as Exhibit 3.1 to Form 8-K filed July 31, 2007).
*(f)	Amendment No. 4 dated April 15, 2008 and effective as of January 1, 2007 to Fourth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated as of April 13, 2005 (filed as Exhibit 3.1 to Form 8-K filed April 21, 2008).
*(g)	Amended and Restated Certificate of Formation of Magellan GP, LLC dated November 15, 2002, as amended on August 12, 2003 (filed as Exhibit 3(f) to Form 10-K filed March 10, 2004).
*(h)	Second Amended and Restated Limited Liability Company Agreement of Magellan GP, LLC dated as of October 20, 2005 (filed as Exhibit 3.1 to Form 8-K filed October 25, 2005).
*(i)	Amendment No. 1 dated July 31, 2007 to Second Amended and Restated Limited Liability Company Agreement of Magellan GP, LLC dated as of October 20, 2005 (filed as Exhibit 3.1 to Form 8-K filed August 2, 2007).

Exhibit No.	Description
*(j)	Amendment No. 2 dated December 3, 2008 to Second Amended and Restated Limited Liability Company Agreement of Magellan GP, LLC dated as of October 20, 2005 (filed as Exhibit 3.1 to Form 8-K filed December 5, 2008).
Exhibit 4	
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*(k)	Second Supplemental Indenture dated as of July 14, 2008 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed July 14, 2008).
*(l)	Unit Purchase Rights Agreement dated as of December 4, 2008 between Magellan Midstream Partners, L.P. and Computershare Trust Company, N.A. (filed as Exhibit 4.1 to Form 8-A filed December 5, 2008).
Exhibit 10	
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*(b)	First Amendment to Seventh Amended and Restated Magellan Midstream Partners Long-Term Incentive Plan effective April 26, 2007 (filed as Exhibit 10.1 to Form 8-K filed April 26, 2007).
(c)	Description of Magellan 2009 Annual Incentive Program.

Exhibit No.	Description
(d)	Summary of Independent Director Compensation Program dated January 22, 2009.
*(e)	Director Deferred Compensation Plan effective October 1, 2006 (filed as Exhibit 10.1 to Form 8-K filed October 4, 2006).
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Exhibit 12	Ratio of earnings to fixed charges.
Exhibit 14	
*(a)	Code of Ethics dated September 1, 2003 by Don R. Wellendorf, principal executive officer (filed as Exhibit 14(a) to Form 10-K filed March 10, 2004).
*(b)	Code of Ethics dated September 1, 2003 by John D. Chandler, principal financial and accounting officer (filed as Exhibit 14(b) to Form 10-K filed March 10, 2004).
Exhibit 21	Subsidiaries of Magellan GP, LLC and Magellan Midstream Partners, L.P.
Exhibit 23	Consent of Independent Registered Public Accounting Firm.
Exhibit 31	
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Exhibit No.	Description
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Exhibit 32	
(a)	Section 1350 Certification of Don R. Wellendorf, Chief Executive Officer.
(b)	Section 1350 Certification of John D. Chandler, Chief Financial Officer.
Exhibit 99	Magellan GP, LLC consolidated balance sheets at December 31, 2008 and 2007 and notes thereto.

* 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, Chief Financial Officer and Treasurer

Date: February 26, 2009

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 26, 2009
/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 26, 2009
/s/ PATRICK C. EILERS **Patrick C. Eilers**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 26, 2009
/s/ JAMES R. MONTAGUE **James R. Montague**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 26, 2009
/s/ GEORGE A. O'BRIEN, JR. **George A. O'Brien, Jr.**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 26, 2009

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