MAGELLAN MIDSTREAM PARTNERS LP
Form 10-K
February 28, 2008

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)**

OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2007
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 x 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 x

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

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. x

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

Large accelerated filer x Accelerated filer ¨ 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 x

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, 2007 was $3,091,508,964.

As of February 27, 2008, there were 66,743,730 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 2008 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, Magellan Midstream Holdings, L.P. s general partner, to provide all general and administrative (G&A) services and operating functions required for our operations. Our organizational structure at December 31, 2007, 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.

(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, 2007, our asset portfolio consists of:

- an 8,500-mile petroleum products pipeline system, including 47 petroleum products terminals serving the mid-continent region of the United States, which we refer to as our petroleum products pipeline system;

- seven petroleum products terminal facilities located along the United States Gulf and East Coasts, which we refer to as our marine terminals, and 27 petroleum products terminals located principally in the southeastern United States, which we refer to as our inland terminals; and

- an 1,100-mile ammonia pipeline system serving the mid-continent region of the United States.

Petroleum Products Industry Background

The United States petroleum products transportation and distribution system links oil refineries to end-users of gasoline and other petroleum products and is comprised of a network of pipelines, terminals, storage facilities, tankers, barges, rail cars 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 2007 published by the Energy Information Administration (EIA), the Gulf Coast region accounted for approximately 43% of total U.S. daily refining capacity and 65% of U.S. refining capacity expansion from 1999 to 2006. 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 8,500 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 47 terminals. The products transported on our pipeline system are largely transportation fuels, and in 2007 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 89%, 87% and 88% of our consolidated total revenues in 2005, 2006 and 2007, respectively. See Note 16 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 2007 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 grow at an average rate of approximately 1.1% per year 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 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 not only demand growth but also major supply shifts that may occur.

Our petroleum products pipeline system has experienced increased shipments over each of the last three years with total shipments increasing by 4% from 2005 to 2007. These volume increases are a result of overall market demand growth, development projects on our system and incentive agreements with shippers utilizing our system. The operating statistics below reflect our petroleum products pipeline system s operations for the periods indicated:

	Year Ended December 31,		
	2005	**2006**	**2007**
Shipments (thousand barrels):			
Refined products			
Gasoline	161,204	164,548	159,807
Distillates	106,137	113,217	119,602
Aviation fuel	22,693	22,060	24,562
LPGs	8,520	9,812	3,232
Total product shipments	298,554	309,637	307,203
Capacity leases	25,234	21,605	30,114
Total shipments, including capacity leases	323,788	331,242	337,317
Daily average (thousand barrels)	887	908	924

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 largest common carrier pipeline for refined petroleum products and LPGs in the United States in terms of pipeline miles. 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 a specific product supply agreement that we assumed in October 2004, our petroleum products blending and fractionation operations and product overages on our pipeline system.

In 2007, our petroleum products pipeline system generated 77% 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 38 of our pipeline system s 47 terminals. Revenues from terminalling and storage at our other nine terminals are at privately negotiated rates.

In 2007, our petroleum products pipeline system generated the remaining 23% 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 sales revenues for the petroleum products pipeline primarily result from: (i) a third-party supply agreement assumed as part of the pipeline system we acquired in October 2004 and (ii) the sale of products that are produced from our petroleum products blending operation and from fractionating transmix. We take title to the products related to these activities, which benefited from high petroleum prices in the last two years. Although the revenues generated from these activities were $627.6 million, $649.2 million and $692.4 million in 2005, 2006 and 2007, respectively, the difference between product sales and product purchases, which we believe better represents the importance of these activities, was $47.5 million, $50.6 million and $66.2 million in 2005, 2006 and 2007, respectively, as product purchases were $580.1 million, $598.6 million and $626.2 million in 2005, 2006 and 2007, respectively. See *Recent Developments* in Management s Discussion and Analysis of Financial Condition and Results of Operations for new developments related to this supply agreement.

Facilities. Our petroleum products pipeline system consists of an 8,500-mile pipeline with 47 terminals and includes more than 29.0 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 2007, 50% of the petroleum products transported on our petroleum products pipeline system originated from 11 direct refinery connections and 50% originated from multiple interconnections with other pipelines.

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

Major Origins Refineries (Listed Alphabetically)

Company	Refinery Location
Coffeyville Resources	Coffeyville, KS
ConocoPhillips	Ponca City, OK
Flint Hills Resources (Koch)	Pine Bend, MN
Frontier Oil	El Dorado, KS
Gary-Williams Energy	Wynnewood, OK
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

The most significant of our pipeline connections is to the Explorer Pipeline in Glenpool, Oklahoma, which transports product from the large refining complexes located on the Texas and Louisiana Gulf Coast. Our pipeline system is also connected to all Chicago, Illinois area refineries through the West Shore Pipe Line.

As set forth in the table below, our system is connected to multiple pipelines.

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. These agreements have remaining terms ranging from one to ten years. Approximately 60% of the shipments in 2007 were subject to these supplemental agreements. 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, 2007, our petroleum products pipeline system had approximately 60 transportation customers. The top 10 shippers included several independent refining companies, integrated oil companies and one farm cooperative, and revenues attributable to these top 10 shippers for the year ended December 31, 2007 represented 37% of total revenues for our petroleum products pipeline system and 50% of revenues excluding product sales.

Product sales are primarily to trading and marketing companies. The most significant of these sales relate to a third-party supply agreement, which expires in 2018. Under this agreement, we are obligated to supply approximately 400,000 barrels of petroleum products per month to one of our customers. See *Recent Developments* in Management s Discussion and Analysis of Financial Condition and Results of Operations for new developments related to this supply agreement.

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, terminals on our pipeline system provide 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 reduced pipeline shipments, if any, of refined products.

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 10%, 12% and 11% of our consolidated total revenues in 2005, 2006 and 2007, respectively. See Note 16 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 23.0 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. Once the product has reached our marine terminals, we store the product for a period of time ranging from a few days to several months. 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 2007, approximately 96% of our marine terminal capacity was utilized. As of December 31, 2007, approximately 95% 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 2007, we were a party to storage agreements pursuant to which we received a discounted storage rate fee and a variable-rate terminalling fee. The variable-rate terminalling fee is based on a percentage of the net profits from trading activities conducted by certain of our customers. If our customer s trading profits fall below a specified amount or are negative, our variable-rate terminalling fee will be zero. However, if our customer s trading activities result in profit, our variable-rate terminalling fee will be 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 choose 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 approximately 5.0 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 rail car loading rack. During 2007, gasoline represented approximately 60% of the product volume distributed through our inland terminals, with the remaining 40% 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.

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 rail car. In addition to throughput fees, we generate revenues by charging our customers a fee for injecting additives into gasoline, diesel and aviation fuel, and for filtering jet 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 an 1,100-mile common carrier ammonia pipeline system. Our pipeline system transports ammonia from production facilities in Texas and Oklahoma to terminals in the Midwest. The ammonia we transport is primarily used as a nitrogen fertilizer, an important element for maintenance of high crop yields. The ammonia pipeline system segment accounted for 1% of our consolidated revenues each year in 2005, 2006 and 2007. See Note 16 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. These tariffs are postage stamp tariffs, which means that each shipper pays a defined rate per ton of ammonia shipped regardless of the distance that ton of ammonia travels on our pipeline. In addition to transportation tariffs, we also earn revenue 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. A third-party pipeline company has provided the operating services and a portion of the general and administrative services for our ammonia pipeline system under an operating agreement with us since 2003, but we plan to assume operating responsibility of this pipeline system on July 1, 2008.

Facilities. Our ammonia pipeline is one of two ammonia pipelines operating in the United States and has a maximum annual delivery capacity of approximately 900,000 tons. 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 and to store ammonia for future use. These facilities also provide our customers with the ability 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. We have transportation agreements with our three customers which extend through June 2008, and we are currently negotiating new multi-year agreements. Each transportation contract contains a ship-or-pay mechanism whereby each customer has committed a tonnage that it expects to ship. Aggregate annual commitments from our customers for the period July 1, 2007 through June 30, 2008 are 525,000 tons. If a customer fails to ship its annual commitment, that customer must pay for the pipeline capacity it did not use.

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 revenues derived by customers that accounted for 10% or more of our consolidated total revenues is provided in the table below. Customers A, B and C were customers of our petroleum products pipeline system. Customer C purchased petroleum products from us pursuant to a third-party supply agreement during 2005 and 2006. In 2006, this third-party supply agreement was assigned to Customer A. See *Recent Developments* in Management s Discussion and Analysis of Financial Condition and Results of Operations for new developments related to this supply agreement. No other customer accounted for more than 10% of our consolidated total revenues for 2005, 2006 or 2007. In general, accounts receivable from these customers are due within 10 days. In addition, we use letters of credit and cash deposits from these customers to mitigate our credit exposure.

	2005	2006	2007
Customer A	0%	18%	33%
Customer B	9%	11%	13%
Customer C	42%	29%	0%
Total	51%	58%	46%

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, which extends through 2010, is set at the producer price index for finished goods (PPI-FG) plus 1.3%.

Under the indexing regulations, a pipeline can request a rate increase that exceeds index levels for indexed rates using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rate resulting from application of the FERC index. Approximately 40% of our petroleum products pipeline system is subject to this indexing methodology. In addition to rate indexing and cost-of-service filings, interstate oil pipeline companies may elect to support rate filings by obtaining authority to charge market-based rates or through an agreement between all shippers and the pipeline company that a rate is acceptable. 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 (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. 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 the new policy is generally favorable for pipelines that were organized as pass-through entities, it still entails rate risk due to the case-by-case review requirement. In December 2005, the FERC issued its first case-specific oil pipeline review of the income tax allowance issues, reaffirming the Policy Statement. In May 2007, the D.C. Circuit issued an opinion upholding the analysis of the Policy Statement. The FERC issued two orders in 2007 affirming that tax allowances are appropriate cost elements to be recovered by master limited partnerships (MLP s).

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 compliant 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.

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. Except as may be disclosed below, we are not aware of any potential claims by third parties that could be materially adverse to our results of operations, financial position or cash flow.

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 at both December 31, 2006 and 2007. 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 response to the EPA s information request was submitted during November 2001. In March 2004, we received an additional information request from the EPA and notice from the U.S. Department of Justice (DOJ) that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Section 311(b) of the Act in regards to 32 releases. The DOJ stated that the maximum statutory penalty for the releases was in excess of $22.0 million, which assumed that all releases are violations of the Act and that the EPA would impose the maximum penalty. The EPA further indicated that some of those releases may have also violated the Spill Prevention Control and Countermeasure requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these releases if the EPA were to successfully seek and obtain injunctive relief. We responded to the March 2004 information request in a timely manner and have entered into an agreement that provides both parties an opportunity to negotiate a settlement prior to initiating litigation. We have accrued an amount for this matter based on our best estimates that is less than $22.0 million. Most of the amount we have accrued was included as part of the environmental indemnification settlement we reached with our former affiliate (see *Indemnification Settlement* description below). The DOJ and EPA have added to their original demand a release that occurred in the second quarter of 2005 from our petroleum products pipeline near our Kansas City, Kansas terminal and a release that occurred in the first quarter of 2006 from our petroleum products pipeline near Independence, Kansas. Our accrual includes these additional releases. We are in ongoing negotiations with the EPA; 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.

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 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, 2007, known liabilities that would have been covered by these indemnifications were $42.9 million. Through December 31, 2007, we have spent $45.5 million of the indemnification settlement proceeds for indemnified matters, including $20.1 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 $5.9 million and $6.9 million at December 31, 2006 and December 31, 2007, 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. We have recognized liabilities for all environmental remediation obligations known to us.

In addition, due to the age of our facilities, we could have instances where hazardous substances, such as asbestos, lead, and/or polychlorinated biphenyls (PCBs), were utilized in conducting operations and maintenance activities under previous ownership. The former use of these hazardous substances could result in environmental impacts that would require handling or remediation in accordance with state and federal regulations. We have identified PCB impacts at two of our petroleum products terminals that we are in the process of assessing. It is possible that in the near term after our assessment process is complete, the PCB contamination levels could require corrective actions. Management is unable at this time to determine what these corrective actions and associated costs might be. However, the costs of these corrective actions could be material to our results of operations and cash flows.

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 and are in the process of implementing corrective actions associated with identified potential deficiencies. We have estimated that the remaining corrective actions will cost approximately $3.5 million, with spending to occur through 2009.

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 noncompliance 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.

Floating Roof Emissions. Operational needs require us to empty our tanks at various times. When our tanks with internal floating roofs are emptied, the tanks emit petroleum vapors. Historically, these emissions were not reported or addressed in facility air permits because the EPA had no approved method to quantify the emissions event. However, the EPA adopted the American Petroleum Institute s methodology for calculating these particular emissions as their approved standard in 2006. It is currently unclear what impact, if any, this adoption by the EPA will have on our current operational practices, emission control and reporting requirements, emission fees and existing air permits. These impacts could be material to our results of operations or cash flows.

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.

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 (1) title defects to our ammonia pipeline that arise before February 2016 and (2) 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, Magellan Midstream Holdings GP, LLC (MGG GP), employs various personnel who are assigned to conduct our operational and administrative functions. At December 31, 2007, MGG GP employed 1,127 employees, of whom 596 were assigned to conduct the operations of our petroleum products pipeline system, 242 were assigned to conduct the operations of our petroleum products terminals and 289 were assigned to provide general and administrative (G&A) services.

(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 2007.

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
- the increase in the use of alternative fuel sources, such as biofuels such as ethanol and biodiesel, fuel cells and solar, electric and battery-powered engines. Current laws will require a significant increase in the quantity of biofuels 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.

A third-party supply agreement we assumed in connection with the acquisition of certain pipeline and terminal assets during October 2004 requires that we purchase and maintain certain inventories of petroleum products. In addition, we maintain product inventory related to our petroleum products blending and fractionation operations, as well as in connection with the operation of our pipeline and terminals. Significant fluctuations in market prices of petroleum products could result in losses or lower profits from these operations, 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, which was 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 and 2007, we recognized revenues from variable-rate fee agreements of $9.4 million and $2.8 million, respectively. We have negotiated similar agreements pursuant to which we will receive a share of any net trading profits above a specified amount during 2008, but we will not share in any net trading losses. The 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 2008 could be zero.

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 rates that were in excess of a just and reasonable level when taking into consideration our pipeline system s cost of service. In addition, shippers may challenge the lawfulness of tariff rates that have become final and effective. The FERC may also investigate such rates absent shipper 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 if they exceed the new maximum allowable rate. The FERC s indexing methodology is subject to a five-year review, and in March 2006, the FERC approved the methodology of PPI-FG plus 1.3% for the annual adjustment related to the next five-year period, commencing July 1, 2006. Changes in PPI-FG plus 1.3% might not fully reflect actual increases in the costs associated with the pipelines subject to indexing, which would impair our ability to recover costs associated with our indexed rates.

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 reparations to complaining shippers for up to two years prior to the complaint.

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 outcome of certain FERC proceedings involving FERC policy statements is uncertain and 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.

In December 2006, FERC issued another 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. 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. The tax allowance policy was upheld by the D.C. Circuit in May 2007. FERC continues to refine its tax allowance policy in case-by-case reviews, and how the Policy Statement is applied in practice to pipelines owned by publicly traded partnerships could affect the rates of FERC regulated pipelines owned by such partnerships.

Pending before FERC is a proceeding on the appropriate composition of proxy groups for purposes of determining natural gas and oil pipeline equity returns to be included in cost-of-service based rates. In a policy statement issued in July 2007, FERC proposed to permit inclusion of publicly traded partnerships in the proxy group analysis relating to return on equity determinations in rate proceedings, provided that the analysis is limited to actual publicly traded partnership distributions capped at the level of the pipeline s earnings and that evidence is provided in the form of a multiyear analysis of past earnings demonstrating a publicly traded partnership s ability to provide stable earnings over time. In November 2007, the FERC requested additional comments regarding the method to be used for creating growth forecasts for publicly traded pipeline partnerships, and FERC held a technical conference on this issue in January 2007.

The ultimate outcomes of the FERC s income tax allowance and proxy group proceedings are not certain and may result in new policies that would limit the amount of income tax allowance permitted to be recovered in regulated rates or that would disallow the full use of distributions to unitholders by publicly traded pipeline partnerships in any proxy group comparisons used to determine return on equity in future proceedings. Any such policy developments may adversely affect our ability to achieve a reasonable return or impose limits on our ability to include a full income tax allowance in cost of service.

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, as well as from other means of transporting, storing and distributing petroleum products, including from other pipeline systems, terminal operators and integrated refining and marketing companies that own their own terminal facilities. 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.

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 control 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 17 states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Also, as a result of the U.S. Supreme Court s decision in April 2007 in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate greenhouse gas emissions from mobile sources (*e.g.*, cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court s holding in *Massachusetts* that greenhouse gases fall under the federal Clean Air Act s definition of air pollutant may also result in future regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas where we conduct business could adversely affect our operations and demand for our services.

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 pipeline 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 mid-continent 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, which could reduce the volumes transported on our petroleum products pipelines 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.

Our operations depend on employees who are assigned to conduct them, including employees covered by collective bargaining agreements which must be periodically renegotiated.

The employees assigned to conduct our operations are employees of an affiliate of our general partner. Of the employees assigned to our petroleum products pipeline system as of December 31, 2007, approximately 200, or 35%, were represented by the United Steel Workers Union and covered by a collective bargaining agreement that extends through January 31, 2009. We expect to begin negotiations on a new agreement in the second half of 2008. If we are unable to reach a new agreement with the union, or if the new terms agreed to are not favorable, our results of operations, cash flows and ability to pay cash distributions could be adversely affected.

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, 2007, we had $163.5 million of floating rate borrowings outstanding on our revolving credit facility. In addition, we have effectively converted $100.0 million of our fixed-rate debt to floating-rate debt using an interest rate swap agreement. 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.

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.

Certain executive officers of our general partner own interests in MGG MH, which currently owns the general partner interest and limited partner interests in MGG. As a result, these officers could experience additional conflicts between our interests and the interests of MGG.

Affiliates of our general partner may compete with us.

Under our partnership agreement, it is not a breach of our general partner s fiduciary duties for affiliates of our general partner to engage in activities that compete with us. For example, both MGG, which owns our general partner, and MGG s general partner are partially owned by an affiliate of Carlyle/Riverstone Global Energy and Power Fund II, L.P. (CRF), which also owns, through affiliates, an interest in the general partner of SemGroup, L.P. (SemGroup) and an interest in Knight, Inc. (formerly known as Kinder Morgan, Inc.), which owns the general partner of Kinder Morgan Energy Partners, L.P. (KMP). SemGroup and KMP are engaged in the transportation, storage and distribution of refined petroleum products. In addition, CRF may acquire other entities that compete with us. We will compete directly with SemGroup, KMP and perhaps other entities in which CRF has an interest for acquisition opportunities throughout the United States, and we compete directly with KMP in the storage of refined petroleum products in the southeastern United States. We potentially will compete with SemGroup, KMP and these other entities for new business or extensions of the existing services provided by our operating partnerships, creating actual and potential conflicts of interest between us and affiliates of our general partner. In addition, an affiliate of SemGroup is a significant customer of ours.

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 is one vacancy. Four of the seven members of our board of directors are affiliates of MGG, which owns our general partner and is partially owned by MGG MH. Since 2006, MGG MH has been selling its interest in MGG. When MGG MH no longer owns an interest in MGG, the composition of our and MGG s general partner s board of directors will likely change, resulting in new directors that may not continue with the same business strategies.

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. 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 maximum effective rate of 0.7% of our gross income 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 common 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, members of Congress are considering substantive changes to the definition of qualifying income under Internal Revenue Code section 7704(d) for the first time in 20 years. It is possible that these efforts could result in changes to the existing U.S. tax laws that affect publicly traded partnerships, including us. Although the legislation would not apply to us as currently proposed, we are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common 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 conclusions of our counsel or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel s conclusions or 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 result 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 non-U.S. 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 non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. 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 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. 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 will likely 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 will likely 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 will likely 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***

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 response to the EPA s information request was submitted during November 2001. In March 2004, we received an additional information request from the EPA and notice from the U.S. Department of Justice (DOJ) that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Section 311(b) of the Act in regards to 32 releases. The DOJ stated that the maximum statutory penalty for the releases was in excess of $22.0 million, which assumed that all releases are violations of the Act and that the EPA would impose the maximum penalty. The EPA further indicated that some of those releases may have also violated the Spill Prevention Control and Countermeasure requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these releases if the EPA were to successfully seek and obtain injunctive relief. We responded to the March 2004 information request in a timely manner and have entered into an agreement that provides both parties an opportunity to negotiate a settlement prior to initiating litigation. We have accrued an amount for this matter based on our best estimates that is less than $22.0 million. Most of the amount we have accrued was included as part of the environmental indemnification settlement we reached with our former affiliate (see *Indemnification Settlement* description below). The DOJ and EPA have added to their original demand a release that occurred in the second quarter of 2005 from our petroleum products pipeline near our Kansas City, Kansas terminal and a release that occurred in the first quarter of 2006 from our petroleum products pipeline near Independence, Kansas. Our accrual includes these additional releases. We are in ongoing negotiations with the EPA; 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.

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 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.

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, 2008, we had 223 registered holders and approximately 51,000 beneficial holders of record of our limited partner units. The year-end closing sales price of our limited partner units was $38.60 on December 29, 2006, the last trading day for 2006, and $43.36 on December 31, 2007. The high and low closing sales price ranges for and distributions paid on our limited partner units by quarter for 2006 and 2007 are as follows:

	2006			2007		
Quarter	**High**	**Low**	**Distribution***	**High**	**Low**	**Distribution***
1st	$ 33.27	$ 30.82	$ 0.56500	$ 47.27	$ 37.90	$ 0.61625
2nd	$ 35.20	$ 32.80	$ 0.57750	$ 51.00	$ 43.95	$ 0.63000
3rd	$ 36.93	$ 33.65	$ 0.59000	$ 47.81	$ 39.81	$ 0.64375
4th	$ 39.24	$ 36.85	$ 0.60250	$ 43.99	$ 39.72	$ 0.65750

* 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 26, 2007, we issued 185,673 limited partner units primarily to settle award grants under our equity-based incentive compensation plan that vested on December 31, 2006. 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. Our general partner did not make an equity contribution associated with these equity issuances and, as a result, cash distributions paid after January 24, 2008 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	98.011%	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%

We must distribute all of our cash on hand at the end of each quarter, less reserves established by our general partner. We refer to this cash as available cash, which is defined in our partnership agreement. The amount of available cash may be greater than or less than the minimum quarterly distribution. We currently pay quarterly cash distributions of $0.6575 per limited partner unit, which entitles our general partner to receive approximately 31% of the total cash distributions paid and intend to continue increasing our cash distributions. However, we cannot guarantee that future distributions will increase or continue at current levels.

Unitholder Return Performance Presentation

The following graph compares the performance of our limited partner units with the performance of the Standard & Poors 500 Stock Index (S&P 500) and a peer group index for the period commencing on

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December 31, 2002. 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), formerly known as Valero L.P. (NYSE:VLI), and TEPPCO Partners, L.P. (NYSE: TPP).

	12/31/02	12/31/03	12/31/04	12/30/05	12/29/06	12/31/07
Magellan Midstream Partners, L.P.	100.0	165.3	207.1	241.8	309.5	367.8
Peer Index	100.0	145.2	152.4	157.2	188.2	215.8
S&P 500	100.0	98.6	109.3	114.6	132.7	140.0

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.

Equity Compensation Plans

The information relating to our equity compensation plans required by Item 5 is incorporated by reference to information presented in our Proxy Statement under caption Securities Authorized for Issuance Under Equity Compensation Plans .

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

During October 2004, we acquired certain pipeline and terminal assets, which had a significant impact on our operating results, financial position and cash flows following this acquisition.

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 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 our environmental liabilities and indemnifications can be found in Item 1. *Business Environmental & Safety*, Item 7. *Management s Discussion and Analysis of Financial Condition and Results of Operations* and Note 17 Commitments and Contingencies in the 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 16 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 G&A expense, which management does not consider when evaluating the core profitability of an operation.

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. As a result, historical financial results for our segments have been adjusted to conform to the current period s presentation.

	Year Ended December 31,				
	2003	2004	2005	2006	2007
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenues	$ 372,848	$ 419,117	$ 500,196	$ 558,301	$ 607,845
Product sales revenues	112,312	275,769	636,209	664,569	709,564
Affiliate management fee revenues		488	667	690	712
Total revenues	485,160	695,374	1,137,072	1,223,560	1,318,121
Operating expenses	166,883	179,657	229,795	244,526	251,601
Product purchases	99,907	255,599	582,631	605,341	633,909
Equity earnings		(1,602)	(3,104)	(3,324)	(4,027)
Operating margin	218,370	261,720	327,750	377,017	436,638
Depreciation and amortization expense	36,081	41,845	56,307	60,852	63,792
Affiliate G&A expense	56,846	54,466	61,131	67,112	72,587
Operating profit	125,443	165,409	210,312	249,053	300,259
Interest expense, net	34,536	35,435	48,258	53,010	51,045
Debt prepayment premium		12,666			1,984
Write-off of unamortized debt placement fees		5,002			
Debt placement fee amortization	2,830	3,056	2,871	2,681	2,144
Other (income) expense, net	(92)	(953)	(300)	634	728
Income before provision for income taxes	88,169	110,203	159,483	192,728	244,358
Provision for income taxes[a]					1,568
Net income	$ 88,169	$ 110,203	$ 159,483	$ 192,728	$ 242,790
Basic net income per limited partner unit	$ 1.66	$ 1.72	$ 2.04	$ 2.24	$ 2.60
Diluted net income per limited partner unit	$ 1.66	$ 1.72	$ 2.03	$ 2.24	$ 2.60
Balance Sheet Data:					
Working capital (deficit)[b]	$ 77,438	$ 71,737	$ (206)	$ (341,371)	$ (15,563)
Total assets	1,194,624	1,817,832	1,876,518	1,952,649	2,101,194
Long-term debt[b]	569,100	789,568	782,639	518,609	914,536
Partners capital	498,149	789,109	807,990	806,482	871,164
Cash Distribution Data:					
Cash distributions declared per unit[c]	$ 1.59	$ 1.76	$ 2.06	$ 2.34	$ 2.55
Cash distributions paid per unit[c]	$ 1.53	$ 1.72	$ 1.97	$ 2.29	$ 2.49

	Year Ended December 31,				
	2003	2004	2005	2006	2007
	(in thousands, except operating statistics)				
Other Data:					
Operating margin (loss):					
Petroleum products pipeline system	$ 163,636	$ 195,024	$ 249,435	$ 284,190	$ 351,246
Petroleum products terminals	45,767	56,339	67,224	86,703	85,368
Ammonia pipeline system	8,094	7,328	7,685	2,541	(3,008)
Allocated partnership depreciation costs[d]	873	3,029	3,406	3,583	3,032
Operating margin	$ 218,370	$ 261,720	$ 327,750	$ 377,017	$ 436,638
EBITDA:					
Net income	$ 88,169	$ 110,203	$ 159,483	$ 192,728	$ 242,790
Provision for income taxes[a]					1,568
Debt prepayment premium		12,666			1,984
Write-off of unamortized debt placement fees		5,002			
Debt placement fee amortization	2,830	3,056	2,871	2,681	2,144
Interest expense, net	34,536	35,435	48,258	53,010	51,045
Depreciation and amortization	36,081	41,845	56,307	60,852	63,792
EBITDA	$ 161,616	$ 208,207	$ 266,919	$ 309,271	$ 363,323
Operating statistics:					
Petroleum products pipeline system:					
Transportation revenue per barrel shipped	$ 0.964	$ 0.996	$ 1.025	$ 1.060	$ 1.147
Volume shipped (million barrels)	237.8	256.0	298.6	309.6	307.2
Petroleum products terminals:					
Marine terminal average storage utilized (million barrels per month)[e]	16.0	18.4	20.4	20.9	21.8
Inland terminal throughput (million barrels)	55.3	93.6	101.3	110.1	117.3
Ammonia pipeline system:					
Volume shipped (thousand tons)	614	765	713	726	716

(a) Beginning in 2007, the state of Texas implemented a partnership-level tax based on a percentage of the financial results of our assets 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 our pipeline notes (see Note 12 Debt in the accompanying consolidated financial statements) 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) During 2003, certain assets were contributed to us and were recorded as property, plant and equipment at the partnership level and not at the segment 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, 2007, our three operating segments include:

- petroleum products pipeline system, which is primarily comprised of our 8,500-mile petroleum products pipeline system, including 47 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.

Beginning in 2007, commercial and operating responsibilities for our two inland terminals in the Dallas, Texas area were transferred from the petroleum products terminals to the petroleum products pipeline system. As a result, our historical financial results and operating statistics have been adjusted to conform to the current year s presentation.

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, 2007.

Recent Developments

Distribution. During January 2008, the board of directors of our general partner declared a quarterly cash distribution of $0.6575 per unit for the period of October 1 through December 31, 2007. As a result, we declared distributions equal to $2.55 per unit related to 2007 compared to $2.34 per unit related to 2006, an increase of 9%. The $0.6575 per unit distribution was paid on February 14, 2008 to unitholders of record on February 6, 2008.

Interest rate derivatives. In January 2008, we entered into a total of $200.0 million of forward starting interest rate swap agreements to hedge against variability of future interest payments on debt that we anticipate issuing no later than June 2008. Proceeds of the anticipated debt issuance will be used to refinance borrowings on our revolving credit facility. The interest rate swap agreements have a 10-year term. The effective date of the agreements is June 30, 2008, at which time the agreements require a mandatory cash settlement. Assuming no changes in swap spreads between the date we entered these agreements and the date on which they are settled, these agreements will effectively fix the rate on the treasury component of our anticipated debt issuance at approximately 3.9%.

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 which expires in 2018, we are obligated to supply approximately 400,000 barrels of petroleum products per month to one of our customers. As a result, the magnitude of our product sales revenues and product purchases increased substantially beginning in late 2004. The gross margin we realize from this agreement can be substantially higher in periods when refined petroleum product prices are increasing and substantially lower in periods when product prices are declining 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.

During February 2008, we entered into an agreement to assign this supply obligation to a third-party entity effective March 1, 2008. We will continue to earn transportation revenues for the product we ship related to this supply agreement but will no longer recognize associated product sales and purchases. However, we will share in a portion of the assignor s trading profits or losses relating to the assigned product supply agreement, but we will not be required to hold inventories.

As of December 31, 2007, we held inventory valued at $49.3 million for the third-party supply agreement. Upon the March 1, 2008 effective date, we will sell any remaining inventory to the assignor and recognize the resulting gain or loss based on inventory values on that date. The impact of this supply agreement on our historical financial results (not including transportation revenues for products shipped associated with the products supply agreement) is provided in the table below (in millions):

	Year Ended December 31,		
	2005	2006	2007
Product sales revenues	$ 462.6	$ 414.1	$ 421.5
Product purchases	(452.8)	(416.7)	(411.3)
Amortization of liability[a]	3.1	2.6	2.6
Ad valorem taxes	(0.2)	(0.4)	(0.4)
Total	$ 12.7	$ (0.4)	$ 12.4

(a) When we assumed the supply agreement in October 2004, we recorded its fair value as a liability, which we have been amortizing to product sales revenues over the contract term.

The balance of the products supply agreement liability at December 31, 2007 was $26.9 million. This liability will be written off on March 1, 2008 when we assign the supply agreement to a third-party entity. The new agreement requires us to share in a portion of the assignor s trading profits and losses; therefore, we will record a liability of approximately $5.0 million associated with this new agreement. The fair value of this liability will be determined by using probability-weighted discounted estimated cash flows. We expect to recognize the difference of approximately $22.0 million as a gain in the first quarter of 2008.

In the event the third-party entity assuming this obligation is unable to perform on this agreement through the 2018 expiration date, the supply agreement obligation will revert back to us.

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 have historically included costs from projects relating both to current and past events. For further discussion of indemnified environmental matters, see Business Environmental & Safety under Item 1 of this Annual Report on Form 10-K.

A prolonged period of high refined product prices could lead to a reduction in demand and result in lower shipments on our pipeline system and reduced demand for our terminal services. In addition, fluctuations in the prices of refined petroleum products impact the amount of cash our petroleum products pipeline system generates from its third-party supply agreement and its petroleum products blending and fractionation operations. Please read Recent Developments above for discussion of our recent assignment of this third-party supply agreement to another company. Also, 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 2007, the pipeline generated more than 75% 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 operations, our third-party supply agreement and in connection with the operations of our pipeline system and terminals. Please read Recent Developments above for discussion of our recent assignment of this third-party supply agreement to a third-party entity, thus eliminating our need to carry inventory to satisfy this agreement effective March 2008. Although our petroleum products blending and fractionation operations and third-party supply agreement generate significant revenues, 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 has operated our ammonia pipeline system since February 2003, but we plan to assume operating responsibility of this pipeline system on July 1, 2008. Operating costs and expenses are principally fixed costs related to field personnel and maintenance. Other costs, including power, fluctuate with volumes transported on the pipeline. We do not expect a material increase in our operating expenses in 2008 as a result of us assuming operating responsibility of the ammonia pipeline.

Growth Projects

We remain focused on growth and have significantly increased our operations over the past two years through organic growth projects that expand or upgrade our existing facilities. Industry themes continue to drive our current expansion projects, including:

- increased storage demand with significant opportunity to build tankage, backed by long-term customer commitments;
- government regulations for renewable fuels such as ethanol and biodiesel as fuel additives, which require us to add infrastructure on which we will earn additional profits;
- refinery expansions in the Mid-Continent and Gulf Coast regions, which require additional pipeline capacity to deliver the increased production; and
- connectivity to key growth markets such as Denver, Colorado and Dallas and Houston, Texas.

We spent $150.5 million on organic growth projects during 2007 and $135.6 million in 2006. Further, we expect to spend approximately $210.0 million in 2008 on projects that are currently underway, with additional spending of $25.0 million expected in 2009 and $5.0 million 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 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 general and administrative (G&A) costs, which management does not consider when evaluating the core profitability of an operation.

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)				
Revenues:				
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
Product sales	664.6	709.6	45.0	7
Affiliate management fees	0.7	0.7		
Total revenues	1,223.6	1,318.1	94.5	8
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 purchases	605.3	633.9	(28.6)	(5)
Equity earnings	(3.3)	(4.0)	0.7	21
Operating margin	377.1	436.6	59.5	16
Depreciation and amortization	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
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 current 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 risk associated with certain known environmental sites was 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. We expect the amount of system integrity spending to decline significantly on our ammonia pipeline system during the latter part of 2008 as we complete the work necessary for the high consequence area testing mandated by federal regulations.

Product sales revenues primarily resulted from a third-party product supply agreement, our petroleum products blending operation, system product gains and transmix fractionation. Revenues from product sales were $709.6 million for the year ended December 31, 2007 while product purchases were $633.9 million, resulting in gross margin from these transactions of $75.7 million. The gross margin resulting from product sales and purchases for the 2007 period increased $16.4 million compared to gross margin for the 2006 period of $59.3 million, resulting from product sales for the year ended December 31, 2006 of $664.6 million and product purchases of $605.3 million. The increase in 2007 margins was primarily attributable to higher product prices. 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. Please read Recent Developments above for discussion of our recent assignment of the third-party supply agreement effective March 2008, thus eliminating our need to carry inventory to satisfy this agreement.

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 increased by $2.8 million related to capital expansion projects over the past 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, 2007 and 2006, we were responsible for paying G&A costs of $57.4 million and $53.2 million, respectively. MGG reimburses us for our actual cash G&A costs that exceed these amounts. The amount of G&A reimbursed to us for the years ended 2007 and 2006 was $4.1 million and $1.7 million, respectively. Based on our G&A agreement and assuming no acquisitions or divestitures that would result in adjustments to the upper and lower cap amounts, the maximum amount of G&A reimbursements we expect to receive from MGG during 2008 will be $1.6 million. We expect 2008 to be the last year we will receive reimbursement from MGG for G&A costs. We currently expect to pay G&A costs, net of reimbursements and equity-based incentive compensation, of approximately $64.3 million during 2008.

Interest expense, net of interest capitalized and interest income, was $51.0 million for the year ended December 31, 2007 compared to $53.0 million for the year ended December 31, 2006. 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 over the last year.

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 compared to $0 in 2006. Beginning in 2007, the state of Texas implemented a partnership-level tax based on the financial results of our assets apportioned to the state of Texas.

Net income was $242.8 million for the year ended December 31, 2007, representing record net income for us, compared to $192.7 million for the year ended December 31, 2006, an increase of $50.1 million, or 26%.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2006

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2005	**2006**	**$ Change**	**% Change**
Financial Highlights ($ in millions, except operating statistics)				
Revenues:				
Transportation and terminals revenues:				
Petroleum products pipeline system	$ 385.6	$ 419.3	$ 33.7	9
Petroleum products terminals	101.9	125.9	24.0	24
Ammonia pipeline system	15.8	16.5	0.7	4
Intersegment eliminations	(3.1)	(3.4)	(0.3)	(10)
Total transportation and terminals revenues	500.2	558.3	58.1	12
Product sales	636.2	664.6	28.4	4
Affiliate management fees	0.7	0.7		
Total revenues	1,137.1	1,223.6	86.5	8
Operating expenses:				
Petroleum products pipeline system	187.5	189.7	(2.2)	(1)
Petroleum products terminals	40.2	47.3	(7.1)	(18)
Ammonia pipeline system	8.2	13.9	(5.7)	(70)
Intersegment eliminations	(6.1)	(6.4)	0.3	5
Total operating expenses	229.8	244.5	(14.7)	(6)
Product purchases	582.7	605.3	(22.6)	(4)
Equity earnings	(3.1)	(3.3)	0.2	6
Operating margin	327.7	377.1	49.4	15
Depreciation and amortization	56.3	60.9	(4.6)	(8)
Affiliate G&A expense	61.1	67.1	(6.0)	(10)
Operating profit	$ 210.3	$ 249.1	$ 38.8	18
Operating Statistics				
Petroleum products pipeline system:				
Transportation revenue per barrel shipped	$ 1.025	$ 1.060		
Volume shipped (million barrels)	298.6	309.6		
Petroleum products terminals:				
Marine terminal average storage utilized (million barrels per month)[(a)]	20.4	20.9		
Inland terminal throughput (million barrels)	101.3	110.1		
Ammonia pipeline system:				
Volume shipped (thousand tons)	713	726		

(a) For the year ended December 31, 2005, represents the average storage capacity utilized for the four months we owned our Wilmington, Delaware facility (1.8 million barrels) and the average storage capacity utilized for the full year at our other marine terminals (18.6 million barrels).

Transportation and terminals revenues increased by $58.1 million resulting from higher revenues for each of our business segments as shown below:

an increase in petroleum products pipeline system revenues of $33.7 million primarily attributable to record annual shipments due to higher diesel fuel and gasoline shipments as a result of increased demand from our customers and a higher average transportation rate per barrel shipped, principally related to our mid-year tariff increase. We also earned more ancillary revenues related to additive and terminal services during 2006;

an increase in petroleum products terminals revenues of $24.0 million due to higher revenues at both our marine and inland terminals. Our marine terminal revenues increased due to our Wilmington, Delaware marine terminal, which we acquired in September 2005, revenue from two variable-rate storage agreements benefiting 2006 results as well as higher storage rates, additive fees and expansion projects. Revenues also increased at our inland terminals due to higher additive fees and throughput volumes; and

an increase in ammonia pipeline system revenues of $0.7 million due to higher tariffs associated with our transportation agreements, which became effective July 1, 2005, and increased volumes.

Operating expenses increased by $14.7 million. Each of our business segments recognized additional expenses as follows:

an increase in petroleum products pipeline system expenses of $2.2 million, primarily due to system integrity spending for pipeline testing and personnel expenses. These increases were partially offset by more favorable product overages in the current period, which reduce operating expenses;

an increase in petroleum products terminals expenses of $7.1 million primarily related to expenses associated with our Wilmington marine terminal, which we acquired in September 2005, and higher power and personnel costs at our other terminals; and

an increase in ammonia pipeline system expenses of $5.7 million primarily related to higher system integrity costs and environmental expenses.

Product sales revenues primarily resulted from a third-party product supply agreement, our petroleum products blending operation, system product gains and transmix fractionation. Revenues from product sales were $664.6 million for the year ended December 31, 2006, while product purchases were $605.3 million, resulting in gross margin from these transactions of $59.3 million. The gross margin resulting from product sales and purchases for the 2006 period increased $5.8 million compared to gross margin for the 2005 period of $53.5 million, resulting from product sales for the year ended December 31, 2005 of $636.2 million and product purchases of $582.7 million. The gross margin increase in 2006 primarily resulted from the impact of high gasoline prices on our petroleum products blending operation, partially offset by lower margin from the third-party supply agreement primarily due to a lower weighted-average inventory cost from 2004 that favorably impacted 2005 results. 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.

Operating margin increased $49.4 million, primarily due to revenues from a marine terminal variable-rate storage agreement, incremental operating results from our recently-acquired Wilmington marine facility and improved utilization and financial results from our other assets.

Depreciation and amortization increased by $4.6 million related to asset acquisitions and capital expansion projects.

Affiliate G&A expense increased by $6.0 million. During 2006, we recognized $3.0 million of non-cash expense associated with certain distribution payments made over the past three years by our affiliate, MGG MH, to an executive officer of our general partner who left the company during late 2006. Although we did not pay for these expenses, we recognized the related non-cash compensation expense in our financial statements. The remainder of the increase was primarily attributable to our equity-based compensation program, which impacted G&A expenses by $9.2 million during 2006 and $7.9 million during 2005. The higher equity-based compensation expense resulted from the increase in our unit price during 2006 and increases in the number of limited partner units management estimates will vest under this program. G&A expenses also were higher during 2006 due to higher employee costs and additional personnel hired to help manage our expansion projects. Excluding the expense associated with MGG MH s payments and our equity-based incentive compensation program, the amount of cash we spend for G&A costs is determined by an agreement we have with MGG, the owner of our general partner. For the years ended December 31, 2006 and 2005, we were responsible for paying G&A costs of $53.2 million and $49.9 million, respectively. MGG reimburses us for our actual G&A costs that exceed these amounts. The amount of G&A reimbursed to us for the years ended 2006 and 2005 was $1.7 million and $3.3 million, respectively.

Interest expense, net of interest capitalized and interest income, was $53.0 million for the year ended December 31, 2006 compared to $48.3 million for the year ended December 31, 2005. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased slightly to $807.2 million during 2006 from $799.4 million during 2005. The weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, increased to 7.1% for the 2006 period from 6.6% for the 2005 period primarily due to rising interest rates. The amount of interest capitalized increased due to the higher level of capital spending in 2006 offset by lower interest income because we used available cash to fund our increased capital expansion projects during 2006.

Net income was $192.7 million for the year ended December 31, 2006 compared to $159.5 million for the year ended December 31, 2005, an increase of $33.2 million, or 21%.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $260.9 million for the year ended December 31, 2007, $304.7 million for 2006 and $224.8 million for 2005.

The $43.8 million decrease from 2006 to 2007 was primarily attributable to:

- a $28.9 million increase in inventories in 2007 versus a $13.4 million increase in inventories in 2006. The increase in inventories during 2007 is primarily due to higher product prices;
- a $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 $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.

The $79.9 million increase from 2005 to 2006 was primarily attributable to:

- a $33.2 million increase in net income in 2006;
- a $13.4 million increase in inventories in 2006 versus a $34.8 million increase in inventories in 2005. The increase in inventories during 2006 is primarily due to higher natural gas liquids purchases in December 2006 initiated to take advantage of favorable product prices at that time, while the increase in 2005 primarily resulted from the third-party supply agreement we assumed in connection with our October 2004 pipeline system acquisition;
- a $16.1 million increase in accounts payable in 2006 versus a $5.1 million increase in accounts payable in 2005 due primarily to the timing of invoices received from our vendors and suppliers; and

> $28.3 million increase in accrued product purchases in 2006 versus a $17.5 million increase in accrued product purchases in 2005 due primarily to the timing of invoices received from our vendors and suppliers.

Net cash used by investing activities for the years ended December 31, 2007, 2006 and 2005 was $193.7 million, $148.3 million and $75.7 million, respectively. 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. Significant expansion capital expenditures during 2007 and 2006 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 2005, we acquired a marine terminal in Wilmington, Delaware for $55.3 million and petroleum products pipeline system terminals in Wichita, Kansas and Aledo, Texas for $10.9 million on a combined basis. In addition, we spent $7.6 million to buy out of obligations related to a portion of our third-party supply agreement and $92.8 million for capital expenditures, excluding acquisitions, which included $28.0 million for maintenance capital and $64.8 million for expansion capital. These cash expenditures were partially offset by our sales of marketable securities which, net of purchases, generated $87.8 million of cash in 2005.

Net cash used by financing activities for the years ended December 31, 2007, 2006 and 2005 was $73.7 million, $186.5 million and $142.5 million, respectively. Cash distributions paid to our unitholders and general partner were $236.1 million during 2007. Net borrowings on our revolving credit facility of $143.0 million and a debt financing 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. Cash was used during 2006 and 2005 primarily to pay cash distributions of $208.0 million and $160.5 million, respectively, to our unitholders and general partner. Capital contributions from our general partner were $40.2 million, $28.7 million and $20.1 million during 2007, 2006 and 2005, respectively, primarily due to payments we received under our May 2004 environmental indemnity settlement and amounts received under the G&A cost cap agreement.

During 2007, we paid $236.1 million in cash distributions to our unitholders and general partner. The quarterly distribution amount associated with the fourth quarter of 2007 was $0.6575 per unit. 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 197,433 common units representing limited partner interests in us on January 25, 2008 (see Note 23 Subsequent Events in the accompanying consolidated financial statements), total cash distributions of $255.2 million would be paid to our unitholders in 2008, of which $79.6 million, or 31%, 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 2007, our net maintenance capital spending was $31.2 million, excluding $6.7 million of spending that would have been covered by indemnifications settled in May 2004 and $1.8 million we have received from insurance reimbursements. We have received the entire $117.5 million under our indemnification settlement agreement. Please see Environmental below for additional description of this agreement.

For 2008, we expect to incur maintenance capital expenditures for our existing businesses of approximately $35.0 million, excluding $10.0 million of maintenance capital that has already been reimbursed to us through our indemnification settlement and third-party reimbursements.

In addition to maintenance capital expenditures, we also incur expansion capital expenditures at our existing facilities. During 2007, we spent cash of approximately $150.5 million for organic growth projects. Based on projects currently underway or in advanced stages of development, we currently plan to spend $210.0 million on organic growth capital in 2008, excluding acquisitions, and approximately $25.0 million in 2009 and $5.0 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 is available through borrowings under our revolving credit facility discussed below, as well as from other borrowings or issuances of debt or limited partner units. If capital markets do not permit us to issue additional debt and equity, our business may be adversely affected and we may not be able to acquire additional assets and businesses or fund organic growth projects.

As of December 31, 2007, total debt reported on our consolidated balance sheet was $914.5 million. The difference between this amount and the $913.5 million face value of our outstanding debt is adjustments related to fair value hedges and unamortized discounts on debt issuances.

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 and extend the maturity date from May 2011 to September 2012. 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, 2007, $163.5 million was outstanding under this facility, and $3.3 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, 2007, the weighted-average interest rate on borrowings outstanding under this facility was 5.4%. 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. Including the impact of amortizing the losses realized on pre-issuance hedges associated with these notes and the interest rate swap which effectively converts $100.0 million of these notes from fixed-rate to floating-rate debt, the weighted-average interest rate on the notes at December 31, 2007 was 5.5%.

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 after underwriters fees and expenses of approximately $246.4 million. The 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, 2007.

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. In October 2004, we entered into a $100.0 million interest rate swap agreement to hedge against changes in the fair value of a portion of our 5.65% notes due 2016. This agreement effectively changes the interest rate on $100.0 million of those notes to a floating rate of six-month LIBOR plus 0.6%, with LIBOR set in arrears. This swap agreement expires on October 15, 2016, the maturity date of the 5.65% notes.

Credit ratings. Our current corporate credit ratings are BBB by Standard and Poor s and Baa2 by Moody s Investor Services.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2007 (in millions):

	Total	< 1 year	1-3 years	3-5 years	> 5 years
Long-term debt obligations[1]	$ 913.5	$	$	$ 163.5	$ 750.0
Interest obligations[2]	739.3	55.4	110.9	108.5	464.5
Operating lease obligations	22.4	3.0	5.9	5.0	8.5
Pension and postretirement medical obligations	22.6	2.7	3.8	1.3	14.8
Purchase commitments:					
Affiliate operating and G&A[3]					
Product purchase commitments[4]	44.9	40.3	2.2	2.3	0.1
Utility purchase commitments	2.5	1.3	1.0	0.2	
Derivative financial instruments[5]					
Equity-based incentive awards[6]	25.1	13.0	12.1		
Environmental remediation[7]	20.1	7.9	6.1	2.7	3.4
Capital project purchase obligations	32.1	32.1			
Maintenance and facility security purchase obligations	6.9	6.8	0.1		
Other purchase obligations	2.0	1.1	0.9		
Supply agreement deposit[8]	18.5				18.5
Total	$ 1,849.9	$ 163.6	$ 143.0	$ 283.5	$ 1,259.8

(1) Excludes market value adjustments to long-term debt associated with qualifying hedges. For purposes of this table, we have assumed that the borrowings under our revolving credit facility as of December 31, 2007 ($163.5 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, 2007 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, 2007 (5.40%).

(3) We have an agreement with affiliates of our general partner to provide our direct operating and G&A services. This agreement has provisions for termination upon 90-day notice by either party. As a result of the termination provisions of this agreement and the requirement to pay only actual costs as they are incurred, we are unable to determine the actual amount of these commitments. The amount we paid for allocated operating and G&A costs during 2007 was $128.6 million.

(4) We have an agreement to supply a customer with up to approximately 400,000 barrels of petroleum products per month until the agreement expires in 2018. Related to this agreement, we have entered into a separate buy-or-make-whole agreement with a supplier for 13,000 barrels of petroleum products per day through May 31, 2008. 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.

(5) On December 31, 2007, we had outstanding interest rate swap agreements to hedge against the fair value of $100.0 million of our long-term debt. Because future cash outflows under this derivative agreement, if any, are uncertain, they have been excluded from this table.

(6) Represents the grant date fair value of unit awards accounted for as equity plus the December 31, 2007 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, 2007 and the vesting dates of the awards.

(7) On December 31, 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 ($6.5 million as of December 31, 2007) 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 ($2.0 million) as of December 31, 2007. 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 ($11.6 million as of December 31, 2007) and the estimated timing of those payments based on project progress to date.

(8) This deposit is security for payment performance related to our products supply agreement.

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. Under our accounting policies, 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, which we have collected. As of December 31, 2007, known liabilities that would have been covered by these indemnifications were $42.9 million. Through December 31, 2007, we have spent $45.5 million of the indemnification settlement proceeds for indemnified matters, including $20.1 million of capital costs. We have not reserved the cash received from this indemnity settlement but have used it for our 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 response to the EPA s information request was submitted during November 2001. In March 2004, we received an additional information request from the EPA and notice from the U.S. Department of Justice (DOJ) that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Section 311(b) of the Act in regards to 32 releases. The DOJ stated that the maximum statutory penalty for the releases was in excess of $22.0 million, which assumed that all releases are violations of the Act and that the EPA would impose the maximum penalty. The EPA further indicated that some of those releases may have also violated the Spill Prevention Control and Countermeasure requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these releases if the EPA were to successfully seek and obtain injunctive relief. We responded to the March 2004 information request in a timely manner and have entered into an agreement that provides both parties an opportunity to negotiate a settlement prior to initiating litigation. We have accrued an amount for this matter based on our best estimates that is less than $22.0 million. Most of the amount we have accrued was included as part of the environmental indemnification settlement we reached with our former affiliate (see *Indemnification Settlement* description below). The DOJ and EPA have added to their original demand a release that occurred in the second quarter of 2005 from our petroleum products pipeline near our Kansas City, Kansas terminal and a release that occurred in the first quarter of 2006 involving from our petroleum products pipeline near Independence, Kansas. Our accrual includes these additional releases. We are in ongoing negotiations with the EPA; 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.

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 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 against the DOJ criminal investigations. 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.

PCB impacts. We have identified polychlorinated biphenyls (PCB) impacts at two of our petroleum products terminals that we are in the process of assessing. It is possible that in the near term the PCB contamination levels could require corrective actions. We are unable at this time to determine what these corrective actions and associated costs might be. The costs of any corrective actions associated with these PCB impacts could be material to our results of operations and cash flows.

Floating roof emissions. Operational needs require us, at various times, to empty our tanks. When our tanks with internal floating roofs are emptied, the tanks emit petroleum vapors. Historically, these emissions were not reported or addressed in facility air permits because the EPA had no approved method to quantify the emissions event. However, the EPA adopted the American Petroleum Institute s methodology for calculating these particular emissions as their approved standard in 2006. It is currently unclear what impact, if any, this adoption by the EPA will have on our current operational practices, emission control and reporting requirements, emission fees and existing air permits. These impacts could be material to our results of operations or 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. 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 3.0% during 2006, we increased virtually all of our published tariffs by the allowed adjustment of approximately 4.3% effective July 1, 2007. The preliminary estimate for the change in PPI-FG for 2007 is approximately 3.9%. Once PPI-FG is finalized, we expect to increase virtually all of our tariffs by the resulting PPI-FG plus 1.3% on July 1, 2008.

Ammonia operating agreement. A third-party pipeline company currently provides the operating services and a portion of the G&A services for our ammonia pipeline system under an operating agreement with us. This pipeline company has provided notice to us that it will not renew its operating agreement with us upon its scheduled expiration date of June 30, 2008. We plan to assume operating responsibility of our ammonia pipeline at that time. Although we expect to incur transition costs during 2008, we do not expect these incremental costs to have a material impact on our financial results.

Union contract negotiation. Approximately 200 employees supporting our petroleum products pipeline system are represented by the United Steel Workers Union and covered by a collective bargaining agreement that extends through January 2009. We consider our labor relations to be good and expect to begin negotiations for a new contract during late 2008.

***Unrecognized product gains*.** Our petroleum products terminals operations generate product overages and shortages. 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 combined net unrecognized product overages for our petroleum products terminals operations had a market value of approximately $11.1 million as of December 31, 2007. 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. We believe 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, which can be applied retroactively, 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, estimating the costs associated with executing the regulatory phases that can be reasonably estimated and estimating the timing for those expenditures. 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 and additional findings or changes in federal or state regulations. The estimated environmental liability accruals are adjusted as necessary. Changes in our environmental liabilities since December 31, 2005 were as follows (in millions):

Balance	2006		Balance	2007		Balance
12-31-05	Accruals	Expenditures	12-31-06	Accruals	Expenditures	12-31-07
$58.2	$16.4	$(16.8)	$57.8	$11.1	$(11.1)	$57.8

During 2006, we increased our environmental liability accruals by $16.4 million. This increase was due to accrual increases related to pipeline product releases of $6.4 million, changes in cost estimates of $2.9 million and costs associated with a cost cap insurance policy of $2.2 million, as a result of entering into a 10-year agreement with an independent contractor to remediate a number of our environmental sites. The remainder of the 2006 accrual increase was primarily attributable to our annual site assessment process. Our 2006 accruals included $4.0 million of liabilities we believe will be reimbursed by our insurance carriers.

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 the current year of $1.6 million and other accrual increases of $1.7 million. Our environmental liabilities at December 31, 2007 included $6.9 million of amounts we believe will be reimbursed by our insurance carriers and other third-party entities.

Our environmental liabilities at December 31, 2007 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 20% and assuming that none of this increase was covered by indemnifications or insurance, our operating expenses would increase by $11.6 million. Because our income taxes consist only of income apportioned to the state of Texas, changes to our income tax expense would be minimal; therefore, operating profit and net income would decrease by approximately $11.6 million, which represents a decrease of 4% of our operating profit and 5% of our net income for 2007. Assuming our current distribution of $0.6575 per unit for the entire year, this additional expense would reduce basic and diluted net income per limited partner unit by approximately $0.10. 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 consist primarily of pipeline, pipeline-related equipment, storage tanks and terminal facility 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. Property, plant and equipment 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, 2006 and 2007, the gross book value of our property, plant and equipment was $2.3 billion and $2.4 billion, respectively, and we recorded depreciation expense of $59.3 million and $62.2 million during 2006 and 2007, respectively. We believe the accounting estimate relative to estimated asset lives to be 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 32 years, our depreciation expense for 2007 would have increased by $10.3 million. Because our income taxes consist only of income apportioned to the state of Texas, changes to our income tax expense would be minimal; therefore, operating profit and net income would decrease by this same amount, which represents a decrease of 3% of our operating profit and 4% of net income for 2007. Assuming our current distribution of $0.6575 per unit for the entire year, this additional expense would reduce basic and diluted net income per limited partner unit by approximately $0.10. 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 .

New Accounting Pronouncements

In December 2007, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (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 that the initial adoption of this Statement will have a material impact on our results of operations, financial position 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 will have a material impact on our results of operations, financial position 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 results of operations, financial position 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 results of operations, financial position or cash flows.

In October 2006, the FASB adopted SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans.* SFAS No. 158 requires an employer to recognize the over-funded or under-funded status of a defined benefit postretirement plan as an asset or liability in its balance sheet and recognize changes in the funded status in the year in which the changes occur through comprehensive income. SFAS No. 158 was required to be adopted for financial statements issued after December 15, 2006. We adopted SFAS No. 158 in December 2006 and, as a result, recorded an increase in our pension and postretirement liabilities of $17.6 million, with an offsetting increase to accumulated other comprehensive loss.

In October 2006, the FASB adopted Financial Staff Position (FSP) No. FAS 123(R)-5, *Amendment of FASB Staff Position FAS 123(R)-1.* This FSP addresses whether a modification of an instrument in connection with an equity restructuring should be considered a modification for purposes of applying FSP FAS 123(R)-1, *Classification and Measurement of Freestanding Financial Instruments Originally Issued in Exchange for Employee Services under FASB Statement No. 123(R).* This FSP clarified that awards issued to an employee in exchange for past or future employee services that is subject to Statement 123(R) will continue to be subject to the recognition and measurement provisions of Statement 123(R) throughout the life of the instrument, unless its terms are modified when the holder is no longer an employee. However, only for purposes of this FSP, a modification does not include a change to the terms of the award if that change is made solely to reflect an equity restructuring that occurs when the holder is no longer an employee. The provisions in this FSP are required to be applied in the first reporting period beginning after October 10, 2006. We adopted this FSP on January 1, 2007, and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In October 2006, the FASB adopted FSP No. FAS 123(R)-6, *Technical Corrections of FASB Statement No. 123(R).* This FSP clarifies that on the date any equity-based incentive awards are determined to no longer be probable of vesting, any previously recognized compensation cost should be reversed. Further, the FSP clarifies that an offer, made for a limited time period, to repurchase an equity-based incentive award should be excluded from the definition of a short-term inducement and should not be accounted for as a modification pursuant to paragraph 52 of Statement 123(R). The provisions in this FSP were required to be applied in the first reporting period beginning after October 20, 2006. We adopted this FSP on January 1, 2007, and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In September 2006, the FASB adopted SFAS No. 157, *Fair Value Measurements.* SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with GAAP and expands disclosures about fair value measurements. While SFAS No. 157 will not impact our valuation methods, it will expand our disclosures of assets and liabilities which are recorded at fair value. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We adopted this standard in 2007 and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In September 2006, the FASB issued FSP No. AUG AIR-a, *Accounting for Planned Major Maintenance Projects.* This FSP prohibits the accrual of any estimated planned major maintenance costs because the accrued liabilities do not meet the definition of a liability under Statement of Financial Accounting Concepts No. 6, *Elements of Financial Statements.* The FSP also requires disclosure of an entity s accounting policies relative to major maintenance. The guidance provided in this FSP was required to be applied to the first fiscal year following December 31, 2006. We adopted this FSP on January 1, 2007, and its adoption did not have a material impact on our results of operations, financial position or cash flows. Our accounting policy regarding maintenance projects, which states that expenditures for maintenance, repairs and minor replacements are charged to operating expense in the period incurred, is included in our significant accounting policy statements under *Property, Plant and Equipment* in Note 2 Summary of Significant Accounting Policies in the accompanying consolidated financial statements.

In February 2006, the FASB issued FSP No. FAS 123(R)-4, *Classification of Options and Similar Instruments Issued as Employee Compensation That Allow for Cash Settlement Upon the Occurrence of a Contingent Event.* This FSP provides that long-term equity incentive awards can still qualify for equity treatment if they contain a clause that allows for the payment of cash to award recipients under certain circumstances, such as a change in control of the general partner of a limited partnership. We adopted this FSP in February 2006 and its adoption did not have a material impact on our results of operations, financial position or cash flows.

Related Party Transactions

Transactions between us and our affiliates are accounted for as affiliate transactions. We have a 50% ownership interest in Osage Pipeline and are paid a management fee for its operation. During each of 2005, 2006 and 2007, we received operating fees from Osage Pipeline 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,		
	2005	**2006**	**2007**
MGG allocated operating expenses	$ 65,360	$	$
MGG allocated G&A expenses	60,261		
MGG GP allocated operating expenses	1,551	73,920	81,184
MGG GP allocated G&A expenses	870	40,830	45,300
MGG MH allocated G&A expenses		3,000	2,149

Under our services agreement with MGG, we reimbursed MGG for all payroll and benefit costs it incurred through December 24, 2005. On December 24, 2005, the employees necessary to conduct our operations were transferred to MGG GP, the services agreement with MGG was terminated and a new services agreement with MGG GP was executed. Consequently, we now reimburse MGG GP for the costs of employees necessary to conduct our operations. The affiliate payroll and benefits accrual associated with this agreement at December 31, 2006 and 2007 was $18.7 million and $23.4 million, respectively, and the long-term affiliate pension and benefits accruals associated with this agreement at December 31, 2006 and 2007 were $29.3 million and $22.4 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.

In June 2003, MGG entered into an omnibus agreement whereby MGG agreed to reimburse us for G&A expenses (excluding equity-based compensation) in excess of a G&A cap as defined in the omnibus agreement. The amount of G&A costs required to be reimbursed by MGG to us under this agreement was $3.3 million, $1.7 million and $4.1 million in 2005, 2006 and 2007, respectively. We do not expect to receive reimbursements under this agreement beyond 2008.

A former executive officer of our general partner had an investment in MGG MH. This former executive officer left the company during the fourth quarter of 2006 and we were allocated $3.0 million of non-cash G&A compensation expenses associated with certain distribution payments made by MGG MH to this individual over the previous three-year period. During 2007, we were allocated $2.1 million of non-cash G&A compensation expense, with a corresponding increase in partners capital, for payments by MGG MH made to one of our executive officers.

When MGG purchased our general partner interest in June 2003, it agreed to assume obligations for $21.9 million of our environmental liabilities. Those obligations were paid in full by December 31, 2006. See Note 17 Commitments and Contingencies in the accompanying consolidated financial statements for further discussion of this matter.

Other Related Party Transactions. MGG, which owns our general partner, is partially owned by an affiliate of Carlyle/Riverstone Global Energy and Power Fund II, L.P. (CRF). During the period June 17, 2003 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. The board of directors of our general partner adopted procedures internally to assure that our proprietary and confidential information was protected from disclosure to competing companies in which CRF owned an interest. As part of these procedures, CRF agreed that none of its representatives would serve on our general partners board of directors and on the boards of directors of competing companies in which CRF owned an interest. CRF is part of an investment group that has 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 remove their representatives from our general partner s board of directors. CRF s agreement with the FTC was announced on January 25, 2007, and as of January 30, 2007, all of the representatives of CRF voluntarily resigned from the board of directors of our general partner.

During the period January 25, 2005 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 period, 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. Through our affiliates, 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 the period January 25, 2005 through January 30, 2007 is provided in the following table (in millions):

	January 25, 2005 through December 31, 2005	Year Ended December 31, 2006	January 1, 2007 Through January 30, 2007
Product sales revenues	$ 144.8	$ 177.1	$ 20.5
Product purchases	90.0	63.2	14.5
Terminalling and other services revenues	5.9	4.4	0.3
Storage tank lease revenue	2.8	3.4	0.4
Storage tank lease expense	1.0	1.0	0.1

In addition to the above, we provide common carrier transportation services to SemGroup. As of December 31, 2006, we had recognized a receivable of $4.0 million from and a payable of $18.8 million to SemGroup and its affiliates. The receivable was included with the accounts receivable amount and the payable was included with the accounts payable amount on our December 31, 2006 consolidated balance sheets.

In February 2006, we signed an agreement with an affiliate of SemGroup under which we agreed to construct two 200,000 barrel tanks on our property at El Dorado, Kansas, to sell these tanks to SemGroup s affiliate and to lease these tanks back under a 10-year operating lease. During 2006, we received $6.1 million associated with this transaction from SemGroup s affiliate, which we reported as proceeds from sale of assets on our consolidated statements of cash flows that accompany this report. We received no funds associated with this transaction during the 2007 period in which SemGroup was classified as a related party.

During the period January 1, 2005 through June 25, 2007, CRF had an ownership interest in the general partner of Buckeye Partners, L.P. (Buckeye). In 2005, we incurred $0.3 million of operating expenses with Norco Pipe Line Company, LLC, which is a subsidiary of Buckeye. We incurred no operating expenses with Buckeye or its subsidiaries during 2006 or 2007.

During May 2005, our general partner s board of directors appointed John P. DesBarres as an independent board member. Mr. DesBarres currently serves as a board member for American Electric Power Company, Inc., of Columbus, Ohio (AEP). For the period May 1, 2005 through December 31, 2005, and the years ended December 31, 2006 and 2007, our operating expenses included $1.7 million, $2.9 million and $2.7 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, 2006 or 2007.

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, 2007, our executive officers collectively owned approximately 5% of MGG MH, which owned 14% of MGG. Therefore, our executive officers indirectly benefit from distributions paid to our general partner. In 2005, 2006 and 2007, distributions paid to our general partner, based on its general partner interest and incentive distribution rights, totaled $30.1 million, $56.3 million and $70.3 million, respectively. In addition, during 2005, MGG received distributions totaling $5.0 million related to the common and subordinated units it owned at the time.

During February 2006, MGG sold 35% of its MGG limited partner units in an initial public offering. We did not receive any of the proceeds from MGG s initial public offering and neither our ownership structure nor our operations were materially impacted by this transaction. In connection with the closing of this offering, 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. We issued limited partner units in January 2007 in connection with our long-term incentive compensation plan. MMP GP did not make equity contributions associated with this issuance, and as a result, its general partner ownership interest was reduced from 2.0% to 1.995%. See Note 23 Subsequent Events for a discussion of further changes in MMP GP s general partner ownership interest.

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 may cause future results to 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:

- price fluctuations for natural gas liquids and refined petroleum products;
- overall demand for natural gas liquids, refined petroleum products, natural gas, oil and ammonia in the United States;
- weather patterns materially different than historical trends;
- development of alternative energy sources;
- increased use of biofuels such as ethanol and biodiesel;
- 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;
- our ability to satisfy our product purchase obligations at historical purchase terms;
- 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;
- changes in the throughput or interruption in service on petroleum products pipelines owned and operated by third parties and connected to our petroleum products terminals or petroleum products pipeline system;
- loss of one or more of our three customers on our ammonia pipeline system;
- an increase in the competition our operations encounter;
- the occurrence of an operational hazard or unforeseen interruption 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 general economic conditions in the United States;

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;

a change of control of our general partner, which could, under certain circumstances, result in our debt becoming due and payable;

the condition of the capital markets in the United States;

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 pay the amounts owed to us;

conflicts of interests between us, our general partner, MGG, MGG s general partner and related parties of MGG and its general partner;

the ability of our general partner, its affiliates or related parties to enter into certain agreements that could negatively impact our financial position, results of operations and cash flows;

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 are 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.

As of December 31, 2007, we had $163.5 million outstanding on our variable rate revolving credit facility. We had no other variable rate debt outstanding; however, because of an interest rate swap agreement discussed below, we are exposed to interest rate market risk on an additional $100.0 million of our debt. Considering this swap agreement and the amount outstanding on our revolving credit facility as of December 31, 2007, our annual interest expense would change by $0.3 million if LIBOR were to change by 0.125%. At December 31, 2006, we had $20.5 million outstanding on our variable rate revolving credit facility and was exposed to interest rate market risk on an additional $350.0 million of our debt through interest rate swap agreements.

During 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 have accounted for this interest rate hedge as a fair value hedge. The notional amount of the interest rate swap agreement is $100.0 million. Under the terms of the agreement, we receive 5.65% (the interest rate of the $250.0 million senior notes) and pay LIBOR plus 0.6%. This hedge effectively converts $100.0 million of our 5.65% fixed-rate debt to floating-rate debt. The interest rate swap agreement began on October 15, 2004 and expires on October 15, 2016. Payments settle in April and October of each year with LIBOR set in arrears. We recognized a deferred liability of $1.2 million and a long-term asset of $2.7 million at December 31, 2006 and 2007, respectively, for the fair value of this agreement.

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, 2007 and 2006, we had commitments under forward purchase contracts for product purchases that will be accounted for as normal purchases totaling approximately $57.8 million and $1.7 million, respectively, and we had commitments under forward sales contracts for product sales that will be accounted for as normal sales totaling approximately $76.1 million and $36.1 million, respectively. The increase in the amounts of forward purchase and sales contracts from December 31, 2006 to December 31, 2007 primarily relate to us addressing market conditions associated with our butane blending activities.

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, 2007 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, 2007, 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, 2007 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, 2007. The report, which expresses an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2007, is included below 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, 2007, 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, 2007 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, 2007 and 2006, and the related consolidated statements of income, partners capital, and cash flows for each of the three years in the period ended December 31, 2007 of Magellan Midstream Partners, L.P. and our report dated February 27, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma

February 27, 2008

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, 2007 and 2006, and the related consolidated statements of income, partners capital, and cash flows for each of the three years in the period ended December 31, 2007. 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, 2007 and 2006, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 10 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, 2007, 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 27, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma

February 27, 2008

MAGELLAN MIDSTREAM PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

(In thousands, except per unit amounts)

	Year Ended December 31, 2005	2006	2007
Transportation and terminals revenues	$ 500,196	$ 558,301	$ 607,845
Product sales revenues	636,209	664,569	709,564
Affiliate management fee revenues	667	690	712
Total revenues	1,137,072	1,223,560	1,318,121
Costs and expenses:			
Operating	229,795	244,526	251,601
Product purchases	582,631	605,341	633,909
Depreciation and amortization	56,307	60,852	63,792
Affiliate general and administrative	61,131	67,112	72,587
Total costs and expenses	929,864	977,831	1,021,889
Equity earnings	3,104	3,324	4,027
Operating profit	210,312	249,053	300,259
Interest expense	53,371	57,478	57,264
Interest income	(4,296)	(2,097)	(1,767)
Interest capitalized	(817)	(2,371)	(4,452)
Debt placement fee amortization	2,871	2,681	2,144
Debt prepayment premium			1,984
Other (income) expense	(300)	634	728
Income before provision for income taxes	159,483	192,728	244,358
Provision for income taxes			1,568
Net income	$ 159,483	$ 192,728	$ 242,790
Allocation of net income:			
Limited partners interest	$ 135,579	$ 148,881	$ 173,330
General partner s interest	23,904	43,847	69,460
Net income	$ 159,483	$ 192,728	$ 242,790
Basic net income per limited partner unit	$ 2.04	$ 2.24	$ 2.60
Weighted average number of limited partner units outstanding used for basic net income per unit calculation	66,361	66,361	66,547
Diluted net income per limited partner unit	$ 2.03	$ 2.24	$ 2.60
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation	66,625	66,613	66,700

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS

(In thousands)

	December 31, 2006	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 6,390	$
Restricted cash	5,283	
Accounts receivable (less allowance for doubtful accounts of $51 and $10 at December 31, 2006 and 2007, respectively)	51,730	62,834
Other accounts receivable	13,288	10,696
Affiliate accounts receivable	483	208
Inventory	91,550	120,462
Other current assets	8,294	10,882
Total current assets	177,018	205,082
Property, plant and equipment	2,260,608	2,435,890
Less: accumulated depreciation	557,869	615,329
Net property, plant and equipment	1,702,739	1,820,561
Equity investments	24,087	24,324
Long-term receivables	6,920	7,506
Goodwill	23,945	23,945
Other intangibles (less accumulated amortization of $5,196 and $6,743 at December 31, 2006 and 2007, respectively)	8,633	7,086
Debt placement costs (less accumulated amortization of $9,592 and $2,170 at December 31, 2006 and 2007, respectively)	5,829	6,368
Other noncurrent assets	3,478	6,322
Total assets	$ 1,952,649	$ 2,101,194
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable	$ 55,549	$ 39,622
Affiliate accounts payable	11,008	12,947
Affiliate payroll and benefits	18,676	23,364
Accrued interest payable	9,266	7,197
Accrued taxes other than income	17,460	21,039
Environmental liabilities	34,952	36,127
Deferred revenue	22,901	20,797
Accrued product purchases	63,098	43,230
Current portion of long-term debt	270,839	
Other current liabilities	14,640	16,322
Total current liabilities	518,389	220,645
Long-term debt	518,609	914,536
Long-term affiliate payable	8,133	1,878
Long-term affiliate pension and benefits	29,278	22,370
Other deferred liabilities	48,945	48,929
Environmental liabilities	22,813	21,672
Commitments and contingencies		
Partners capital:		

Common unitholders (66,361 units and 66,546 units outstanding at December 31, 2006 and 2007, respectively)	1,166,600	1,192,031
General partner	(341,267)	(309,389)
Accumulated other comprehensive loss	(18,851)	(11,478)
Total partners capital	806,482	871,164
Total liabilities and partners capital	$ 1,952,649	$ 2,101,194

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Year Ended December 31,		
	2005	**2006**	**2007**
Operating Activities:			
Net income	$ 159,483	$ 192,728	$ 242,790
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	56,307	60,852	63,792
Debt placement fee amortization	2,871	2,681	2,144
Debt prepayment premium			1,984
Loss on sale and retirement of assets	8,334	8,031	8,548
Equity earnings	(3,104)	(3,324)	(4,027)
Distributions from equity investment	3,300	4,125	3,800
Equity method incentive compensation expense		1,770	3,076
Pension settlement expense and amortization of prior service cost and actuarial loss			3,231
Changes in components of operating assets and liabilities (Note 3)	(2,389)	37,816	(64,394)
Net cash provided by operating activities	224,802	304,679	260,944
Investing Activities:			
Purchases of marketable securities	(50,500)		
Sales of marketable securities	138,302		
Property, plant and equipment:			
Additions to property, plant and equipment	(92,791)	(168,544)	(190,182)
Proceeds from sale of assets	2,994	6,313	961
Changes in accounts payable		13,934	(4,434)
Partial buyout of third-party supply obligation	(7,566)		
Acquisition of business	(55,263)		
Acquisitions of assets	(10,863)		
Net cash used by investing activities	(75,687)	(148,297)	(193,655)
Financing Activities:			
Distributions paid	(160,494)	(207,966)	(236,144)
Net borrowings under revolver	13,000	7,500	143,000
Borrowings under notes			248,900
Payments on notes	(15,100)	(14,345)	(272,555)
Debt placement costs		(426)	(2,683)
Payment of debt prepayment premium			(1,984)
Net receipt from financial derivatives			4,556
Capital contributions by affiliate	20,087	28,742	40,205
Change in outstanding checks			3,026
Other	48	14	
Net cash used by financing activities	(142,459)	(186,481)	(73,679)
Change in cash and cash equivalents	6,656	(30,099)	(6,390)
Cash and cash equivalents at beginning of period	29,833	36,489	6,390
Cash and cash equivalents at end of period	$ 36,489	$ 6,390	$
Supplemental non-cash financing activity:			
Issuance of common units in settlement of 2004 long-term incentive plan awards	$	$	$ 7,406

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, 2005	$ 1,058,913	$ 101,222	$ (369,104)	$ (1,922)	$ 789,109
Comprehensive income:					
Net income	123,273	12,306	23,904		159,483
Amortization of loss on cash flow hedges				210	210
Additional minimum pension liability				(343)	(343)
Total comprehensive income					159,350
Conversion of subordinated units to common units (2.8 million units)	33,147	(33,147)			
Affiliate capital contributions			20,087		20,087
Distributions	(117,942)	(12,456)	(30,096)		(160,494)
Other			(62)		(62)
Balance, December 31, 2005	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

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Basis of Presentation

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, Magellan Midstream Holdings, L.P. s general partner, to provide all general and administrative (G&A) services and operating functions required for our operations. Our organizational structure at December 31, 2007, 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.

Operating Segments

We own a petroleum products pipeline system, petroleum products terminals and an ammonia pipeline system.

Petroleum Products Pipeline System. Our petroleum products pipeline system includes 8,500 miles of pipeline and 47 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 also own an agreement to supply petroleum products to a customer in the west Texas markets. The purchase, transportation and resale of petroleum products associated with this supply agreement have been included in the petroleum products pipeline segment. See Note 23 Subsequent Events for recent events involving this product supply agreement. 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 (NCRA) refinery in McPherson, Kansas and the Frontier refinery in El Dorado, Kansas. Our

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

petroleum products blending and fractionation operations 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 intercompany 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 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.

Restricted Cash. Restricted cash included cash held by us pursuant to the terms of the Magellan Pipeline Company, L.P. (Magellan Pipeline) notes (see Note 12 Debt).

Accounts Receivable and Allowance for Doubtful Accounts. Trade receivables 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, including the customers credit rating. 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

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

financial condition, the customers historical relationship with us and current and projected economic conditions. Trade receivables 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 terminal facility 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 7 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 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

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

pipelines, storage tanks and related facilities would become completely obsolete and require decommissioning. Accordingly, except for a $1.4 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 because 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 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 2005, 2006 or 2007.

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 at December 31, 2006 and 2007. All of our reported goodwill was acquired in transactions involving our petroleum products terminals segment and is allocated to that segment.

The determination of whether goodwill is impaired is based on management s estimate of the fair value of our reporting units as compared to their carrying values. Critical assumptions used in our estimates included: (i) time horizon of 20 years, (ii) revenue growth of 2.5% per year and expense growth of 2.5% per year, except G&A costs, with an assumed growth of 4.0% per year, (iii) weighted-average cost of capital of 10.3% based on assumed cost of debt of 6.5%, assumed cost of equity of 14.0% and a 50%/50% debt-to-equity ratio, (iv) 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 or 2007. 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.

Our 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, 2007 was approximately 10 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 2005, 2006 or 2007. Amortization of other intangible assets was $1.4 million, $1.6 million and $1.5 million during 2005, 2006 and 2007, respectively.

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

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. The amount of the impairment recognized is calculated as the excess of the carrying amount of the asset over the fair value of the assets, as determined either through reference to similar asset sales or by estimating the fair value using a discounted cash flow approach.

Long-lived assets to be disposed of through sales that meet specific criteria are classified as held for sale and are recorded at the lower of their carrying value or the estimated fair value less the cost to sell. Until the assets are disposed of, an estimate of the fair value is re-determined when related events or circumstances change. We had no assets classified as held for sale during 2005, 2006 or 2007.

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 no impairments relative to our long-lived assets during 2005.

In 2006, we recorded a $3.0 million charge against the earnings of our petroleum products pipeline system segment associated with an impairment of our Menard, Illinois terminal. This impairment charge was included in operating expenses on our consolidated statement of income for 2006 and in the petroleum products pipeline system segment amounts in the table included in Note 16 Segment Disclosures for the year ended December 31, 2006. The carrying value of the Menard, Illinois terminal prior to the impairment was $3.6 million. The fair value of the terminal was determined using probability-weighted discounted cash flow techniques.

In 2007, we recorded $2.2 million in charges against the earnings of our petroleum products pipeline system segment associated with the impairment of certain sections of our pipeline in Illinois and Missouri, most of which were idle. The impairment charges were included in operating expenses on our consolidated statements of income for 2007 and in the petroleum products pipeline system segment amounts in the table included in Note 16 Segment Disclosures for the year ended December 31, 2007. One impairment analysis was initiated as a result of an offer from a third party to acquire a section of pipe. The carrying value of the pipeline prior to the impairment was $3.0 million. The fair value of this asset ($1.7 million) was determined using discounted cash flow techniques. The other impairment analysis was initiated when management declared its intention to cease maintenance on a certain section of pipe. The $0.9 million carrying value of this section of pipe was completely written off.

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.

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 result in a significant impact to 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 $8.0 million and $8.8 million at December 31, 2006 and 2007, 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 use interest rate derivatives to help us manage interest rate risk. 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 designed as a cash flow or fair value hedge, is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative 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.

Derivatives that qualify for and are designated as normal purchases and sales are exempted from the fair value accounting requirements of SFAS No. 133, as amended, and are accounted for using traditional accrual accounting. As of December 31, 2007, we had commitments under future contracts for product purchases that will be accounted for as normal purchases totaling approximately $57.8 million. Additionally, we had commitments under future contracts for product sales that will be accounted for as normal sales totaling approximately $76.1 million.

We generally 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 on the balance sheet with the current portion recorded as adjustments to interest expense.

See *Comprehensive Income* in this Note 2 below 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. 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.

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. During 2006 and 2007, we had terminalling agreements with customers under which we provided 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 customers. Under these agreements, we recognized the storage rental and throughput fees as the services were performed; however, we do not receive any revenue from the variable fee if the net trading profits fall below a specified amount or are negative. Therefore, the income we earn related to these shared trading profits is not determinable until the end of the contract term. We defer the recognition of this type of revenue until the end of the applicable contract term. We recognized $6.4 million of terminalling revenues when a contract term expired on January 31, 2006, $3.0 million when a contract term expired on December 31, 2006 and $2.8 million when a contract term expired on December 31, 2007.

Buy / Sell Arrangements. To help manage the supply of inventory and provide specific quantities and grades of products at various locations on our systems, we engage in certain buy / sell arrangements. For those transactions where we are the primary obligor and we assume credit risk and risk of ownership for the associated products, under Emerging Issues Task Force (EITF) Issue No. 99-19, *Recording Revenue Gross as a Principle Versus Net as an Agent*, we record the gross amounts of such transactions in our consolidated statements of income. For those transactions where we act as an agent, are not the primary obligor and do not assume the risk of ownership for the associated products, we record the net amount of such transactions in our consolidated statements of income. The gross amounts recognized under EITF No. 99-19 during 2005, 2006 and 2007 were insignificant.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

G&A Expenses. Under our omnibus agreement, we pay MGG and MGG GP for direct and indirect G&A expenses incurred on our behalf. MGG reimburses 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 and the associated expense is specifically allocated to our general partner.

Unit-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. 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. Expected payments on discounted liabilities are $0.2 million during each year in 2008, 2009, 2010 and 2011 and $0.1 million in 2012. A reconciliation of our undiscounted environmental liabilities to amounts reported on our consolidated balance sheets is as follows (in thousands):

	December 31,	
	2006	**2007**
Aggregated undiscounted environmental liabilities	$ 63,274	$ 63,346
Amount of environmental liabilities discounted	(5,509)	(5,547)
Environmental liabilities, as reported	$ 57,765	$ 57,799

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

to contractors and outside engineering, consulting and law firms. Accrued costs include compensation and benefit expense of internal employees directly involved in remediation efforts. 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 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 17 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 financial results 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.

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 20 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 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 partners proportionate share of income is further adjusted for direct charges.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 obligations 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, 2005	$ (1,922)	$	$	$ (1,922)
Amortization of loss on cash flow hedges	210			210
Additional minimum pension liability		(343)		(343)
Balance, December 31, 2005	(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)

New Accounting Pronouncements.

In December 2007, the Financial Accounting Standards Board (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,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 that the initial adoption of this Statement will have a material impact on our results of operations, financial position 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 will have a material impact on our results of operations, financial position 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. Our adoption of this Implementation Issue did not have a material impact on our results of operations, financial position 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 results of operations, financial position or cash flows.

In October 2006, the FASB adopted SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans.* SFAS No. 158 requires an employer to recognize the over-funded or under-funded status of a defined benefit postretirement plan as an asset or liability in its balance sheet and recognize changes in the funded status in the year in which the changes occur through comprehensive income. SFAS No. 158 was required to be adopted for financial statements issued after December 15, 2006. We adopted SFAS

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

No. 158 in December 2006 and, as a result, recorded an increase in our pension and postretirement liabilities of $17.6 million, with an offsetting increase to accumulated other comprehensive loss of $17.6 million.

In October 2006, the FASB adopted Financial Staff Position (FSP) No. FAS 123(R)-5, *Amendment of FASB Staff Position FAS 123(R)-1.* This FSP addresses whether a modification of an instrument in connection with an equity restructuring should be considered a modification for purposes of applying FSP FAS 123(R)-1, *Classification and Measurement of Freestanding Financial Instruments Originally Issued in Exchange for Employee Services under FASB Statement No. 123(R).* This FSP clarified that awards issued to an employee in exchange for past or future employee services that are subject to Statement 123(R) will continue to be subject to the recognition and measurement provisions of Statement 123(R) throughout the life of the instrument, unless its terms are modified when the holder is no longer an employee. However, only for purposes of this FSP, a modification does not include a change to the terms of the award if that change is made solely to reflect an equity restructuring that occurs when the holder is no longer an employee. The provisions in this FSP are required to be applied in the first reporting period beginning after October 10, 2006. We adopted this FSP on January 1, 2007, and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In October 2006, the FASB adopted FSP No. FAS 123(R)-6, *Technical Corrections of FASB Statement No. 123(R).* This FSP clarifies that on the date any equity-based incentive awards are determined to no longer be probable of vesting, any previously recognized compensation cost should be reversed. Further, the FSP clarifies that an offer, made for a limited time period, to repurchase an equity-based incentive award should be excluded from the definition of a short-term inducement and should not be accounted for as a modification pursuant to paragraph 52 of Statement 123(R). The provisions in this FSP were required to be applied in the first reporting period beginning after October 20, 2006. We adopted this FSP on January 1, 2007, and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In September 2006, the FASB adopted SFAS No. 157, *Fair Value Measurements*. SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with GAAP and expands disclosures about fair value measurements. While SFAS No. 157 did not impact our valuation methods, it expanded our disclosures of assets and liabilities which are recorded at fair value. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including any financial statements for an interim period within that fiscal year. We adopted this statement in 2007, and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In September 2006, the FASB issued FSP No. AUG AIR-a, *Accounting for Planned Major Maintenance Projects.* This FSP prohibits the accrual of any estimated planned major maintenance costs because the accrued liabilities do not meet the definition of a liability under Statement of Financial Accounting Concepts No. 6, *Elements of Financial Statements*. The FSP also requires disclosure of an entity s accounting policies relative to major maintenance. The guidance provided in this FSP was required to be applied to the first fiscal year following December 31, 2006. We adopted this FSP on January 1, 2007, and its adoption did not have a material impact on our results of operations, financial position or cash flows. Our accounting policy regarding maintenance projects, which states that expenditures for maintenance, repairs and minor replacements are charged to operating expense in the period incurred, is included under *Property, Plant and Equipment* above.

In February 2006, the FASB issued FSP No. FAS 123(R)-4, *Classification of Options and Similar Instruments Issued as Employee Compensation That Allow for Cash Settlement Upon the Occurrence of a Contingent Event*. This FSP provides that long-term equity incentive awards can still qualify for equity treatment if they contain a clause that allows for the payment of cash to award recipients under certain circumstances, such as a change in control of the general partner of a limited partnership. We adopted this FSP in

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

February 2006, and its adoption did not have a material impact on our results of operations, financial position or cash flows.

3. Consolidated Statements of Cash Flows

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

	Year Ended December 31,		
	2005	**2006**	**2007**
Accounts receivable and other accounts receivable	$ 901	$ (8,843)	$ (8,512)
Affiliate accounts receivable	3,102	5,052	275
Inventory	(34,758)	(13,395)	(28,912)
Accounts payable	5,114	16,107	(11,493)
Affiliate accounts payable	5,208	5,187	1,939
Affiliate payroll and benefits	(2,247)	1,488	4,688
Accrued interest payable	(232)	(362)	(2,069)
Accrued taxes other than income	1,028	153	3,579
Accrued product purchases	17,459	28,326	(19,868)
Current and noncurrent environmental liabilities	(3,006)	(439)	34
Other current and noncurrent assets and liabilities	5,042	4,542	(4,055)
Total	$ (2,389)	$ 37,816	$ (64,394)

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 recorded a decrease in other intangibles of $1.4 million, an increase in affiliate payroll and benefits of $0.2 million and an increase in long-term affiliate pension and benefits of $15.6 million, resulting in an increase in accumulated other comprehensive loss. At December 31, 2007, we increased long-term affiliate pension and benefits by $0.9 million, resulting in an increase in accumulated other comprehensive loss. We excluded these non-cash amounts from the statements of cash flows.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Allocation of Net Income

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

	Year ended December 31,		
	2005	**2006**	**2007**
Allocation of net income to general partner:			
Net income	$ 159,483	$ 192,728	$ 242,790
Direct charges to general partner:			
Reimbursable G&A costs[a]	3,294	4,665	6,191
Previously indemnified environmental charges	8,502	8,987	4,426
Total direct charges to general partner	11,796	13,652	10,617
Income before direct charges to general partner	171,279	206,380	253,407
General partner s share of income[b]	20.84%	27.86%	31.60%
General partner s allocated share of net income before direct charges	35,700	57,499	80,077
Direct charges to general partner	(11,796)	(13,652)	(10,617)
Net income allocated to general partner	$ 23,904	$ 43,847	$ 69,460
Net income	$ 159,483	$ 192,728	$ 242,790
Less: net income allocated to general partner	23,904	43,847	69,460
Net income allocated to limited partners	$ 135,579	$ 148,881	$ 173,330

(a) A former executive officer of our general partner had an investment in MGG MH. 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 over the previous three years. During 2007, payments by MGG MH of $2.1 million were made to one of our executive officers in connection with the sale by MGG MH of limited partner interests in MGG. Because the limited partners did not pay for either of the above-noted costs, all of these expenses were allocated to our general partner.

(b) 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 the cash distributions we pay, the general partner s percentage share of income is its 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. 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 earnings 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, which was based on actual cash distributions for those periods, plus its allocated share of net income for the second and fourth quarters of 2006, which was 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 assuming that all of the earnings for those periods had been distributed.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2005	2006	2007
Allocation of net income to general partner:			
Net income	$ 159,483	$ 192,728	$ 242,790
Direct charges to general partner:			
Reimbursable G&A costs	3,294	4,665	6,191
Previously indemnified environmental charges	8,502	8,987	4,426
Total direct charges to general partner	11,796	13,652	10,617
Income before direct charges to general partner	171,279	206,380	253,407
General partner s share of income (a)	20.84%	26.77%	28.64%
General partner s allocated share of net income before direct charges	35,700	55,246	72,568
Direct charges to general partner	(11,796)	(13,652)	(10,617)
Net income allocated to general partner	$ 23,904	$ 41,594	$ 61,951
Net income	$ 159,483	$ 192,728	$ 242,790
Less: net income allocated to general partner	23,904	41,594	61,951
Net income allocated to limited partners	$ 135,579	$ 151,134	$ 180,839

(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 partners proportionate share of income is adjusted for direct charges.

Excluding the payments by MGG MH to our executive officers of $3.0 million and $2.1 million in 2006 and 2007, respectively, the reimbursable G&A costs 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 have 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 17 Commitments and Contingencies). Under this agreement, our former affiliate paid us $117.5 million, which we recorded as a capital contribution from our general partner. Since our limited partners do not share in these costs, we have allocated the expenses recognized related to this previous indemnification agreement directly to our general partner.

5. Acquisitions

The acquisition discussed below was accounted for as an acquisition of a business. This acquisition was accounted for under the purchase method and the assets acquired and liabilities assumed were recorded at their estimated fair market values as of the acquisition date.

On September 1, 2005, we acquired a refined petroleum products terminal near Wilmington, Delaware from privately-owned Delaware Terminal Company. This marine terminal has 1.8 million barrels of usable storage capacity. Management believes this facility is strategic to our efforts to grow and provide expanded services for our customers needs in the Mid-Atlantic markets. The operating results of this facility have been included with our petroleum products terminals segment results beginning on September 1, 2005. The land on which the

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

facility sits was purchased in a separate transaction from a local non-profit agency. The allocation of the purchase price was as follows (in thousands):

Purchase price:	
Cash paid, including transaction costs	$ 55,295
Environmental liabilities assumed	250
Total purchase price	$ 55,545
Allocation of purchase price:	
Property, plant and equipment	$ 51,236
Goodwill	2,809
Other intangibles	1,500
Total	$ 55,545

Pro Forma Information (unaudited)

The following summarized pro forma consolidated income statement information assumes that the petroleum product terminal acquisition discussed above had occurred as of January 1, 2004. We have prepared these pro forma financial results for comparative purposes only. These pro forma financial results may not be indicative of the results that would have occurred if we had completed this acquisition as of the period shown below or the results that will be attained in the future. The amounts presented below are in thousands, except per unit amounts:

	Year Ended December 31, 2005		
	As Reported	Pro Forma Adjustments	Pro Forma
Revenues	$ 1,137,072	$ 5,585	$ 1,142,657
Net income	$ 159,483	$ 2,508	$ 161,991
Basic net income per limited partner unit	$ 2.04	$ 0.03	$ 2.07
Diluted net income per limited partner unit	$ 2.03	$ 0.03	$ 2.06
Weighted average number of limited partner units used for basic net income per unit calculation	66,361	66,361	66,361
Weighted average number of limited partner units used for diluted net income per unit calculation	66,625	66,625	66,625

Significant pro forma adjustments include revenues and expenses for the period prior to our acquisition.

The acquisitions discussed below were accounted for as acquisitions of assets.

Petroleum Products Pipeline Terminals. In fourth-quarter 2005, we acquired two terminals that are connected to our 8,500-mile petroleum products pipeline system. The terminals include 0.4 million barrels of combined usable storage capacity and are located in Wichita, Kansas and Aledo, Texas. These terminals were acquired from privately-held companies for cash of approximately $10.9 million, all of which was recorded to property, plant and equipment. The operating results of the Wichita, Kansas and Aledo, Texas terminals have been included in our petroleum products pipeline system segment since their respective acquisition dates.

In conjunction with the acquisition of the Aledo, Texas terminal, we negotiated a partial settlement of the third-party supply agreement we assumed as part of our pipeline system acquisition in October 2004. As a result, we recorded a reduction in the supply agreement liability of $7.6 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. Inventory

Inventories at December 31, 2006 and 2007 were as follows (in thousands):

	2006	2007
Refined petroleum products	$ 45,839	$ 65,215
Natural gas liquids	28,848	16,233
Transmix	14,449	32,824
Additives	2,026	5,812
Other	388	378
Total inventories	$ 91,550	$ 120,462

7. Property, Plant and Equipment

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

	December 31,		Estimated Depreciable Lives	
	2006	2007		
Construction work-in-progress	$ 67,330	$ 112,891		
Land and rights-of-way	53,400	52,937		
Carrier property	1,400,326	1,275,714	6	59 years
Buildings	12,717	14,514	20	53 years
Storage tanks	306,966	411,010	20	40 years
Pipeline and station equipment	114,298	210,064	3	59 years
Processing equipment	255,846	301,115	3	56 years
Other	49,725	57,645	3	48 years
Total	$ 2,260,608	$ 2,435,890		

Carrier property is defined as pipeline assets regulated by the FERC. During 2007, we reclassified $167.6 million of carrier property, primarily into buildings, storage tanks, processing equipment and pipeline and station equipment. Other includes interest capitalized at December 31, 2006 and 2007 of $19.3 million and $22.5 million, respectively. Depreciation expense for the years ended December 31, 2005, 2006 and 2007 was $54.9 million, $59.3 million and $62.2 million, respectively.

8. Equity Investments

We use the equity method to account for our 50% ownership interest in Osage Pipeline. The remaining 50% interest is owned by NCRA. The 135-mile Osage pipeline transports crude oil from Cushing, Oklahoma to El Dorado, Kansas and has connections to the NCRA refinery in McPherson, Kansas, and the Frontier refinery in El Dorado, Kansas. Our agreement with NCRA calls for equal sharing of Osage Pipeline s net income. Income from our equity investment in Osage Pipeline is included with our petroleum products pipeline system. Summarized financial information for Osage Pipeline is presented below (in thousands):

Year Ended December 31,

	2005	2006	2007
Revenue	$ 12,573	$ 14,446	$ 15,787
Net income	$ 7,537	$ 7,976	$ 9,382

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The condensed balance sheet for Osage Pipeline as of December 31, 2006 and 2007 is presented below (in thousands):

	December 31,	
	2006	2007
Current assets	$ 5,015	$ 6,180
Noncurrent assets	$ 4,278	$ 4,917
Current liabilities	$ 697	$ 719
Members equity	$ 8,596	$ 10,378

A summary of our equity investment in Osage Pipeline is as follows (in thousands):

	December 31,	
	2006	2007
Investment at beginning of period	$ 24,888	$ 24,087
Earnings in equity investment:		
Proportionate share of earnings	3,988	4,691
Amortization of excess investment	(664)	(664)
Net earnings in equity investment	3,324	4,027
Cash distributions	(4,125)	(3,800)
Other		10
Equity investment at end of period	$ 24,087	$ 24,324

Our initial investment in Osage Pipeline included an excess net investment amount of $21.7 million, which is being amortized over the average lives of Osage Pipeline s assets. Excess investment is the amount by which our initial investment exceeded our proportionate share of the book value of the net assets of the investment. The unamortized excess net investment amount at December 31, 2006 and December 31, 2007 was $19.8 million and $19.1 million, respectively, and represents additional value of the underlying identifiable assets.

9. 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. Customers A, B and C were customers of our petroleum products pipeline system. Customer C purchased petroleum products from us pursuant to a third-party supply agreement during 2005 and 2006. In 2006, Customer C assigned this third-party supply agreement to Customer A. See Note 23 Subsequent Events for recent events involving our product supply agreement. No other customer accounted for more than 10% of our consolidated total revenue for 2005, 2006 or 2007. In general, accounts receivable from these customers are due within 10 days. In addition, we use letters of credit and cash deposits from these customers to mitigate our credit exposure.

	2005	2006	2007
Customer A	0%	18%	33%
Customer B	9%	11%	13%
Customer C	42%	29%	0%
Total	51%	58%	46%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Concentration of Risks. We transport petroleum products for refiners and marketers in the petroleum industry. The major concentration of our petroleum products pipeline system s revenues is derived from activities conducted in the central United States. Sales to and revenues from our customers generally are secured by warehouseman s liens, providing us with the ability to sell stored customer products to recover unpaid receivable balances, if necessary. We periodically evaluate the financial condition and creditworthiness of other customers to whom we make unsecured sales. We also require additional security as we deem necessary.

The employees assigned to conduct our operations are employees of MGG GP. As of December 31, 2007, MGG GP employed 1,127 employees. We consider our employee relations to be good.

At December 31, 2007, the labor force of 596 employees assigned to our petroleum products pipeline system was concentrated in the central United States. Approximately 35% of these employees are represented by the United Steel Workers Union (USW) and covered by a collective bargaining agreement that expires January 31, 2009. The labor force of 242 employees assigned to our petroleum products terminals operations at December 31, 2007 is primarily concentrated in the southeastern and Gulf Coast regions of the United States. Approximately 10% of these employees are represented by the International Union of Operating Engineers (IUOE) and covered by a collective bargaining agreement that expires in October 2010. A third-party contractor operates our ammonia pipeline and no employees are specifically assigned to those operations.

10. Employee Benefit Plans

Prior to December 2005, MGG sponsored a union pension plan for certain hourly employees (USW plan) and a pension plan for certain non-union employees (Salaried plan), a postretirement benefit plan for selected employees and a defined contribution plan. The sponsorship of these plans was transferred from MGG to MGG GP on December 24, 2005. During 2007, MGG GP established a separate pension fund for the IUOE union employees assigned to our New Haven, Connecticut terminal (IUOE plan). We are required to reimburse the plan sponsor 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. SFAS No. 158 prohibited retroactive application of this statement.

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2006 and 2007 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2006	2007	2006	2007
Change in affiliate benefit obligation:				
Affiliate benefit obligation at beginning of year	$ 39,122	$ 43,849	$ 19,280	$ 15,004
Service cost	5,587	5,765	469	533
Interest cost	2,206	2,539	834	1,026
Plan participants contributions			55	61
Actuarial (gain) loss	332	(837)	720	661
Plan amendment[(a)]			(6,159)	
Benefits paid	(3,398)	(951)	(195)	(216)
Pension settlement		(8,248)		
Affiliate benefit obligation at end of year	43,849	42,117	15,004	17,069
Change in plan assets:				
Fair value of plan assets at beginning of year	25,465	29,416		
Employer contributions	5,259	15,000	140	155
Plan participants contributions			55	61
Actual return on plan assets	2,090	1,382		
Benefits paid	(3,398)	(951)	(195)	(216)
Settlement benefits paid		(8,248)		
Fair value of plan assets at end of year	29,416	36,599		
Funded status at end of year	$ (14,433)	$ (5,518)	$ (15,004)	$ (17,069)
Accumulated affiliate benefit obligation	$ 32,042	$ 31,139		

(a) During 2006, MGG GP increased the deductibles and premiums of the plan participants, which resulted in a decrease in our obligation to MGG GP for the postretirement and medical and life benefit plan.

The amounts included in pension benefits in the above table combine the union pension plans with the Salaried pension plan. At December 31, 2006, the USW plan had an accumulated benefit obligation of $23.2 million, which exceeded the fair value of plan assets of $20.4 million. At December 31, 2007, the fair values of MGG GP s USW and Salaried plans assets exceeded the fair values of their respective accumulated benefit obligations and the fair value of MGG GP s IUOE plan assets was equal to the fair value of its accumulated benefit obligation.

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

Pension Benefits		Other Postretirement Benefits	
2006	2007	2006	2007

Amounts recognized in the consolidated balance sheet:				
Current accrued benefit cost	$	$	$ (159)	$ (217)
Long-term accrued benefit cost	(14,433)	(5,518)	(14,845)	(16,852)
	(14,433)	(5,518)	(15,004)	(17,069)
Accumulated other comprehensive loss:				
Net actuarial loss	6,390	4,980	5,411	5,384
Prior service cost	4,809	4,131	977	800
Net amount recognized in consolidated balance sheet	$ (3,234)	$ 3,593	$ (8,616)	$ (10,885)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Net pension and other postretirement benefit expense for the years ended December 31, 2005, 2006 and 2007 consisted of the following (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2005	**2006**	**2007**	**2005**	**2006**	**2007**
Components of net periodic pension and postretirement benefit expense:						
Service cost	$ 4,215	$ 5,587	$ 5,765	$ 530	$ 469	$ 533
Interest cost	1,866	2,206	2,539	994	834	1,026
Expected return on plan assets	(1,918)	(1,906)	(2,497)			
Amortization of prior service cost	677	678	678	1,798	177	177
Amortization of actuarial loss	25	538	414	575	675	688
Pension settlement expense[(a)]			1,274			
Net periodic expense	$ 4,865	$ 7,103	$ 8,173	$ 3,897	$ 2,155	$ 2,424

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

Additionally, expenses related to the defined contribution plan were $3.8 million, $4.1 million and $4.6 million in 2005, 2006 and 2007, 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 2008 are $0.1 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 2008 are $0.6 million and $0.2 million, respectively.

The weighted-average rate assumptions used to determine benefit obligations as of December 31, 2006 and 2007 were as follows:

		Pension Benefits		Other Postretirement Benefits	
		2006	**2007**	**2006**	**2007**
Discount rate		5.75%	6.50%	6.00%	6.50%
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	N/A	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, 2005, 2006 and 2007 were as follows:

Pension Benefits			Other Postretirement Benefits		
2005	**2006**	**2007**	**2005**	**2006**	**2007**

Discount rate		5.75%	5.50%	5.75%	5.75%	5.50%	6.00%
Expected rate of return on plan assets		8.50%	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	5.00%	4.50%	4.50%	N/A	N/A	N/A
Rate of compensation increase	IUOE plan	N/A	N/A	5.00%	N/A	N/A	N/A

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2008 is 12.8% decreasing systematically to 5.4% by 2015 for pre-65 year-old participants and 8.2% decreasing systematically to 5.4% by 2015 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, 2007, 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	$ 242	$ 226
Change in postretirement benefit obligation	2,519	2,350

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 results from interest cost and changes in interest rates, 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 percentages and the actual weighted-average asset allocation at December 31, 2006 and 2007 were as follows:

	2006		2007	
	Actual	Target	Actual[(a)]	Target
Equity securities	65%	67%	55%	63%
Debt securities	31%	32%	29%	36%
Other	4%	1%	16%	1%

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

As of December 31, 2007, the benefit amounts expected to be paid through December 31, 2017 were as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2008	$ 1,797	$ 217
2009	2,240	331
2010	2,311	443
2011	2,442	562
2012	2,670	688
2013 through 2017	15,934	4,887

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Contributions estimated to be paid in 2008 are $4.6 million and $0.2 million for the pension and other postretirement benefit plans, respectively.

11. Related Party Transactions

Affiliate Entity Transactions. Transactions between us and our affiliates are accounted for as affiliate transactions. We have a 50% ownership interest in Osage Pipeline and are paid a management fee for its operation. During each of 2005, 2006 and 2007 we received operating fees from Osage Pipeline 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,		
	2005	2006	2007
MGG allocated operating expenses	$ 65,360	$	$
MGG allocated G&A expenses	60,261		
MGG GP allocated operating expenses	1,551	73,920	81,184
MGG GP allocated G&A expenses	870	40,830	45,300
MGG MH allocated G&A expenses		3,000	2,149

Under our services agreement with MGG, we reimbursed MGG for all payroll and benefit costs it incurred through December 24, 2005. On December 24, 2005, the employees necessary to conduct our operations were transferred to MGG GP, the services agreement with MGG was terminated and a new services agreement with MGG GP was executed. Consequently, we now reimburse MGG GP for the costs of employees necessary to conduct our operations. The affiliate payroll and benefits accrual associated with this agreement at December 31, 2006 and 2007 was $18.7 million and $23.4 million, respectively, and the long-term affiliate pension and benefits accruals associated with this agreement at December 31, 2006 and 2007 were $29.3 million and $22.4 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.

In June 2003, MGG entered into an omnibus agreement whereby MGG agreed to reimburse us for G&A expenses (excluding equity-based compensation) in excess of a G&A cap as defined in the omnibus agreement. This agreement expires December 31, 2010. The amount of G&A costs required to be reimbursed by MGG to us under this agreement was $3.3 million, $1.7 million and $4.1 million in 2005, 2006 and 2007, respectively. We do not expect to receive reimbursements under this agreement beyond 2008.

A former executive officer of our general partner had an investment in MGG MH. 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 over the previous three-year period, with a corresponding increase in partners capital. During 2007, we recognized $2.1 million of G&A compensation expense, with a corresponding increase in partners capital, for payments made by MGG MH to one of our executive officers.

When MGG purchased our general partner interest in June 2003, it agreed to assume obligations for $21.9 million of our environmental liabilities. Those obligations were paid in full by December 31, 2006. See Note 17 Commitments and Contingencies for further discussion of this matter.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other Related Party Transactions. MGG, which owns our general partner, is 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 the period June 17, 2003 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. The board of directors of our general partner adopted procedures internally to assure that our proprietary and confidential information was protected from disclosure to competing companies in which CRF owned an interest. As part of these procedures, CRF agreed that none of its representatives would serve on our general partners board of directors and on the boards of directors of competing companies in which CRF owned an interest. CRF is part of an investment group that has 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 remove their representatives from our general partner s board of directors. CRF s agreement with the FTC was announced on January 25, 2007, and as of January 30, 2007, all of the representatives of CRF voluntarily resigned from the board of directors of our general partner.

During the period January 25, 2005 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 period, 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. Through our affiliates, 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 the period January 25, 2005 through January 30, 2007 is provided in the following table (in millions):

	January 25, 2005 through December 31, 2005	Year Ended December 31, 2006	January 1, 2007 Through January 30, 2007
Product sales revenues	$ 144.8	$ 177.1	$ 20.5
Product purchases	90.0	63.2	14.5
Terminalling and other services revenues	5.9	4.4	0.3
Storage tank lease revenue	2.8	3.4	0.4
Storage tank lease expense	1.0	1.0	0.1

In addition to the above, we provide common carrier transportation services to SemGroup. As of December 31, 2006, we had recognized a receivable of $4.0 million from and a payable of $18.8 million to SemGroup and its affiliates. The receivable was included with the accounts receivable amount and the payable was included with the accounts payable amount on our December 31, 2006 consolidated balance sheets.

In February 2006, we signed an agreement with an affiliate of SemGroup under which we agreed to construct two 200,000 barrel tanks on our property at El Dorado, Kansas, to sell these tanks to SemGroup s affiliate and to lease these tanks back under a 10-year operating lease. During 2006, we received $6.1 million associated with this transaction from SemGroup s affiliate, which we reported as proceeds from sale of assets on our consolidated statements of cash flows that accompany this report. We received no funds associated with this transaction during the 2007 period in which SemGroup was classified as a related party.

During the period January 1, 2005 through June 25, 2007, CRF had an ownership interest in the general partner of Buckeye Partners, L.P. (Buckeye). In 2005, we incurred $0.3 million of operating expenses with Norco Pipe Line Company, LLC, which is a subsidiary of Buckeye. We incurred no operating expenses with Buckeye or its subsidiaries during 2006 or 2007.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During May 2005, our general partner s board of directors appointed John P. DesBarres as an independent board member. Mr. DesBarres currently serves as a board member for American Electric Power Company, Inc., of Columbus, Ohio (AEP). For the period May 1, 2005 through December 31, 2005, and the years ended December 31, 2006 and 2007, our operating expenses included $1.7 million, $2.9 million and $2.7 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, 2006 or 2007.

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, 2007, our executive officers collectively owned approximately 5% of MGG MH, which owned 14% of MGG, which owns our general partner. Therefore, our executive officers indirectly benefit from distributions paid to our general partner. In 2005, 2006 and 2007, distributions paid to our general partner, based on its general partner interest and incentive distribution rights, totaled $30.1 million, $56.3 million and $70.3 million, respectively. In addition, during 2005 MGG received distributions totaling $5.0 million related to the common and subordinated units it owned at the time.

During February 2006, MGG sold 35% of its MGG limited partner units in an initial public offering. We did not receive any of the proceeds from MGG s initial public offering and neither our ownership structure nor our operations were materially impacted by this transaction. In connection with the closing of this offering, 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. On January 26, 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%

12. Debt

Our debt at December 31, 2006 and 2007 was as follows (in thousands):

	December 31,	
	2006	**2007**
Revolving credit facility	$ 20,500	$ 163,500
6.45% Notes due 2014	249,589	249,634
5.65% Notes due 2016	248,520	252,494
6.40% Notes due 2037		248,908
Magellan Pipeline notes	270,839	
Total debt	$ 789,448	$ 914,536

The face value of our debt outstanding as of December 31, 2007 was $913.5 million. The difference between the face value and carrying value of our debt outstanding was amounts recognized for discounts incurred on debt issuances and market value adjustments to long-term debt associated with qualifying fair value hedges. At December 31, 2007, maturities of our debt were as follows: $0 each year in 2008, 2009, 2010 and 2011; $163.5 million in 2012; and $750.0 million thereafter. Our debt is non-recourse to our general partner.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 corporate purposes, including capital expenditures. Net borrowings under this revolver during 2007 were $143.0 million. As of December 31, 2007, $163.5 million was outstanding under this facility, and $3.3 million was obligated for letters of credit. The obligations 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, 2006 and 2007 was 5.8% and 5.4%, respectively. 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 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 interest hedges associated with these notes (see Note 13 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 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. Including the impact of amortizing the losses realized on the hedges associated with these notes, and the interest rate swap which effectively converts $100.0 million of these notes from fixed-rate to floating-rate debt (see Note 13 Derivative Financial Instruments), the weighted-average interest rate of these notes at December 31, 2006 and 2007 was 6.0% and 5.5%, respectively. The outstanding principal amount of the notes was decreased by $1.2 million at December 31, 2006 and increased by $2.7 million at December 31, 2007 for the fair value of the associated hedge.

6.40% Notes due 2037. In April 2007, we issued $250.0 million of 6.4% 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 from this offering were used to repay a portion of our Magellan Pipeline notes, as discussed below. Including the impact of amortizing the gains realized on the interest hedges associated with these notes (see Note 13 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, 2007.

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

Magellan Pipeline Notes. In connection with the long-term financing of our acquisition of Magellan Pipeline, we and Magellan Pipeline entered into a note purchase agreement in October 2002. At December 31, 2006, $272.6 million of senior notes were outstanding pursuant to this agreement. Because the notes were due in October 2007, this amount less $1.8 million for the change in fair value of associated hedges (see Note 13 Derivative Financial Instruments) was reflected as current portion of long-term debt on our consolidated balance sheet at December 31, 2006. We repaid these notes in May 2007, together with a make-whole premium of $2.0 million and accrued interest of $1.5 million, with net proceeds from a $250.0 million public offering of 30-year senior notes (see *6.40% Notes due 2037* above) and borrowings under our revolving credit facility. Prior to this repayment, we made deposits in an escrow account in anticipation of semi-annual interest payments on these notes. Deposits of $5.3 million at December 31, 2006 were reflected as restricted cash on our consolidated balance sheet.

During the years ending December 31, 2005, 2006 and 2007, total cash payments for interest on all indebtedness, including the impact of related interest rate swap agreements, net of amounts capitalized, were $54.0 million, $57.2 million and $59.2 million, respectively.

13. Derivative Financial Instruments

We use interest rate derivatives to help us manage interest rate risk. The following table summarizes cash flow hedges we had settled and recorded to other comprehensive income (loss) as of December 31, 2007 associated with various debt offerings (in millions):

Hedge	Date	Gain/(Loss)	Amortization Period
Interest rate swaps and treasury lock	May 2004	$ 5.1	10-year life of 6.45% notes
Interest rate swaps	October 2004	(6.3)	12-year life of 5.65% notes
Interest rate swaps	April 2007	5.3	30-year life of 6.40% notes

In addition to the table above and during 2007, the remaining loss on the cash flow hedge associated with the Magellan Pipeline notes was fully amortized. Total amortization of this hedge in 2007 was $0.2 million.

The following 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 recorded a $0.2 million gain associated with these agreements to other comprehensive income. These agreements were unwound 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 an additional gain of $5.0 million ($5.3 million total gain recognized) was recorded to other comprehensive income and is being amortized 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. The total $5.3 million gain on this hedge settlement is included in the above table.

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 the Magellan Pipeline notes. The fair value of these hedges at December 31, 2006 was $(1.8) million, which was recorded to other current liabilities and current portion of long-term debt. We unwound these agreements in May 2007 in conjunction with the repayment of the Magellan Pipeline 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.

Additionally, 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, which were issued in October 2004. We have accounted for this agreement as a fair value hedge. The notional amount of this agreement is $100.0 million and effectively converts $100.0 million of our 5.65% fixed-rate senior notes issued in October 2004 to floating-rate debt. Under the terms of the agreement, we receive the 5.65% fixed rate of the notes and pay LIBOR plus

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0.6%. The agreement began in October 2004 and terminates in October 2016, which is the maturity date of the related notes. Payments settle in April and October each year with LIBOR set in arrears. During each period we record the impact of this swap based on the forward LIBOR curve. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR results in an adjustment to our interest expense. A 0.25% change in LIBOR would result in an annual adjustment to our interest expense of $0.3 million associated with this hedge. The fair value of this hedge at December 31, 2006 was $(1.2) million, which was recorded to other deferred liabilities and long-term debt. The fair value at December 31, 2007 was $2.7 million, which was recorded to other long-term assets and long-term debt.

14. 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. Total rent expense was $6.3 million, $6.3 million and $4.6 million for the years ended December 31, 2005, 2006 and 2007, respectively. Future minimum annual rentals under non-cancelable operating leases as of December 31, 2007, were as follows (in thousands):

2008	$ 2,953
2009	2,944
2010	2,930
2011	2,872
2012	2,144
Thereafter	8,528
Total	$ 22,371

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, 2007, were as follows (in thousands):

2008	$ 92,826
2009	87,287
2010	72,512
2011	54,091
2012	34,672
Thereafter	34,938
Total	$ 376,326

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 minimal amount. Future minimum lease payments

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receivable under this direct-financing leasing arrangement as of December 31, 2007 were $1.3 million each year in 2008, 2009, 2010, 2011 and 2012 and $5.0 million cumulatively for all periods after 2012. The net investment under direct financing leasing arrangements as of December 31, 2006 and 2007 was as follows (in thousands):

	December 31, 2006	December 31, 2007
Total minimum lease payments receivable	$ 12,793	$ 11,514
Less: Unearned income	5,362	4,487
Recorded net investment in direct financing leases	$ 7,431	$ 7,027

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

	December 31, 2006	December 31, 2007
Classification of direct financing leases:		
Current accounts receivable	$ 511	$ 563
Noncurrent accounts receivable	6,920	6,464
Total	$ 7,431	$ 7,027

15. Long-Term Incentive Plan

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 compensation committee of our general partner s board of directors (the Compensation Committee) administers the LTIP and has approved the unit awards discussed below.

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. The award grants do not have an early vesting feature except under certain circumstances following a change in control of our general partner.

The following unit awards have vested:

Grant Date	Unit Awards Granted	Forfeitures	Adjustments to Unit Awards for Attaining Above-Target Financial Results	Units Paid Out to Retirees Prior to Vesting Date	Units Paid Out on Vesting Date	Vesting Date	Value of Unit Awards on Vesting Date (Millions)
February 2003	105,650		91,052	16,100	180,602	12/31/05	$ 5.8
October 2003	21,280				21,280	Various	$ 0.6
January 2004	21,712				21,712	Various	$ 0.7
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

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In January 2006 we settled certain of the February 2003 award grants by purchasing 43,208 limited partner units for $1.4 million and distributing those units to the participants. The remaining awards, including the awards paid out to retirees prior to the vesting date, were settled by issuing net cash payments to the participants. Payments for tax withholdings totaling $4.4 million and employer taxes of $0.3 million were made associated with these awards.

The award grants in October 2003 and January 2004 were made to certain employees who became dedicated to providing services to us following the change in control of our general partner in June 2003. These awards vested as follows: 9,700 in 2003; 21,506 vested in 2004 and 11,786 vested in 2005. In January 2004, we settled the awards that vested in 2003 by issuing net cash payments to the participants and payments for tax withholdings and employer taxes totaling $0.3 million. During 2004, we settled certain awards by purchasing 7,540 of our limited partner units for $0.2 million and distributing those units to the participants and paying associated tax withholdings and employer taxes of $0.1 million. We settled the remainder of the awards in 2005 by purchasing 13,785 limited partner units for $0.4 million and distributing those units to the participants and paying associated tax withholdings and employer taxes of $0.3 million.

We settled the February 2004 award grants in January 2007 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.

We settled the February 2005 and June 2006 award grants in January 2008 by issuing 196,856 limited partner units and distributing those units to the participants (See Note 23 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 $5.1 million in January 2008.

The table below summarizes the unit awards granted by the Compensation Committee that have not yet vested. 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-Target Financial Results	Total Unit Awards Being Accrued	Vesting Date	Unrecognized Compensation Expense at December 31, 2007 (in Millions)	Period Over Which the Unrecognized Expense Will Be Recognized
February 2006	168,105	12,607	139,948	295,446	December 31, 2008	$ 2.8	Next 12 months
Various 2006	9,201	3,132	5,462	11,531	December 31, 2008	$ 0.2	Next 12 months
March 2007	2,640			2,640	December 31, 2008	$ 0.1	Next 12 months
January 2007:							
Tranche 1	49,310	2,219	47,091	94,182	December 31, 2009	$ 2.2	Next 24 months
Tranche 2	49,310				December 31, 2009		
Tranche 3	49,310				December 31, 2009		
Various 2007:							
Tranche 1	3,920	177	3,743	7,486	December 31, 2009	$ 0.2	Next 24 months
Tranche 2	3,920				December 31, 2009		
Tranche 3	3,920				December 31, 2009		

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The intrinsic value of the units being accrued for under the awards granted during 2006 at December 31, 2007 was $13.3 million. We are accounting for these award grants as follows:

The payout for 80% of the unit awards granted during 2006 is based on the attainment of long-term performance metrics. Upon vesting, these award grants must be paid out in limited partner units and we are accounting for these grants as equity. The weighted-average grant date fair value of the award grants was $24.66 per unit, which was based on our unit price on the grant date less the present value of the per-unit estimated cash distributions during the vesting period.

The payout for 20% of the unit awards granted during 2006 is based on the attainment of long-term performance metrics and the individual participant s personal performance. We are accounting for these grants as liabilities; therefore, the compensation expense we recognize is based on the fair value of our units and the percentage of the service period completed at the end of each accounting period. The fair value of these award grants on December 31, 2007 was $40.68 per unit.

The March 2007 unit grants have no performance metrics and no ability to vest beyond the original number awarded. We are accounting for these grants as equity. The grant date fair value of these awards was $42.05 per unit. The intrinsic value of these units at December 31, 2007 was $0.1 million.

The unit awards approved during 2007 (excluding the March 2007 award grants discussed above) have a three-year vesting period; however, the grants are broken into three equal tranches. Under the first tranche, 80% of the payout was based on the attainment of performance metrics set for the 2007 year. Under the second and third tranches, 80% of the payout will be based on the attainment of performance metrics established during the first quarter of each respective fiscal year. Under all three tranches, 20% of the payouts are based on personal performance. Since our financial results for 2007 exceeded the established stretch targets, the accrual units for the first tranche of the 2007 awards included in the table above reflect the maximum number of payout units. The intrinsic value of the units being accrued for under the awards granted during 2007 was $4.4 million at December 31, 2007. We are accounting for these awards as follows:

80% of the unit awards are based on the attainment of performance metrics and are being accounted for as equity. The weighted-average grant date fair value of the first tranche of these equity awards was $32.76 per unit, which was based on our closing unit price on the grant date, less the present value of the per-unit estimated cash distributions during the vesting period. The grant date fair value of these award grants was $2.7 million.

20% of the unit awards are based on personal performance and are being accounted for as liabilities. The compensation expense we recognize for these unit awards is based on the fair value of the awards and the percentage of the requisite service period completed at the end of each accounting period. The fair value of these award grants was $37.86 per unit on December 31, 2007.

Accounting for the second tranche of the 2007 unit awards began in the first quarter of 2008, when the performance metrics for that fiscal year were established by the Compensation Committee. The compensation expense associated with the second tranche will be recognized over a two-year period. Accounting for the third tranche of these unit awards will begin in the first quarter of 2009, when the performance metrics for that fiscal year are established and the associated compensation expense will be recognized over a one-year period.

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Our equity-based incentive compensation expense for 2005, 2006 and 2007 is summarized as follows (in thousands):

	Year Ended December 31,		
	2005	2006	2007
2003 awards	$ 2,440	$ (89)	$
2004 awards	3,937	4,355	519
2005 awards	3,134	4,096	5,721
2006 awards		2,458	3,171
2007 awards			1,102
Total	$ 9,511	$ 10,820	$ 10,513

Long-term incentive awards were also granted to independent members of the board of directors of our general partner pursuant to the long-term incentive plan. Units granted and distributed to directors of our general partner during 2005, 2006 and 2007 were approximately 5,000, 4,000 and 3,600, respectively, and the related compensation expense recognized was approximately $0.2 million in each of 2005, 2006 and 2007.

16. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. Our segments are managed separately because each segment requires different marketing strategies and business knowledge. Management evaluates performance based on segment operating margin, which includes 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. As a result, historical financial results for our segments have been adjusted to conform to the current period s presentation. Consolidated segment profit did not change as a result of these historical reclassifications.

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	Year Ended December 31, 2005				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System (in thousands)	Intersegment Eliminations	Total
Transportation and terminals revenues	$ 385,641	$ 101,848	$ 15,849	$ (3,142)	$ 500,196
Product sales revenues	627,573	9,596		(960)	636,209
Affiliate management fee revenue	667				667
Total revenues	1,013,881	111,444	15,849	(4,102)	1,137,072
Operating expenses	187,477	40,193	8,164	(6,039)	229,795
Product purchases	580,073	4,027		(1,469)	582,631
Equity earnings	(3,104)				(3,104)
Operating margin	249,435	67,224	7,685	3,406	327,750
Depreciation and amortization	36,807	15,345	749	3,406	56,307
Affiliate G&A expenses	44,610	14,386	2,135		61,131
Segment profit	$ 168,018	$ 37,493	$ 4,801	$	$ 210,312
Segment assets	$ 1,287,953	$ 497,004	$ 30,787	$	$ 1,815,744
Corporate assets					60,774
Total assets					$ 1,876,518
Goodwill	$	$ 24,430	$	$	$ 24,430
Additions to long-lived assets	$ 32,905	$ 119,611	$ 564	$	$ 153,080
Investment in equity method investee	$ 24,888	$	$	$	$ 24,888

	Year Ended December 31, 2006				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System (in thousands)	Intersegment Eliminations	Total
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	38,512	17,980	777	3,583	60,852
Affiliate G&A expenses	45,980	18,926	2,206		67,112

Segment 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
Investment in equity method investee	$ 24,087	$	$	$	$ 24,087

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2007				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System (in thousands)	Intersegment Eliminations	Total
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	39,658	20,315	787	3,032	63,792
Affiliate G&A expenses	52,198	17,756	2,633		72,587
Segment 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
Investment in equity method investee	$ 24,324	$	$	$	$ 24,324

17. Commitments and Contingencies

Environmental Liabilities. Liabilities recognized for estimated environmental costs were $57.8 million at both December 31, 2006 and 2007. 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.

Our environmental liabilities include, 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 response to the EPA s information request was submitted during November 2001. In March 2004, we received an additional information request from the EPA and notice from the U.S. Department of Justice (DOJ) that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Section 311(b) of the Act in regards to 32 releases. The DOJ stated that the maximum statutory penalty for the releases was in excess of $22.0 million, which assumed that all releases are violations of the Act and that the EPA would impose the maximum penalty. The EPA further indicated that some of those releases may have also violated the Spill Prevention Control and Countermeasure requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these releases if the EPA were to successfully seek and obtain injunctive relief. We responded to the March 2004 information request in a timely manner and have entered into an agreement that provides both parties an opportunity to negotiate a settlement prior to initiating litigation. We have accrued an amount for this matter based on our best estimates that is less than $22.0 million. Most of the amount we have accrued was included as

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part of the environmental indemnification settlement we reached with our former affiliate (see *Indemnification Settlement* description below). The DOJ and EPA have added to their original demand a release that occurred in the second quarter of 2005 from our petroleum products pipeline near our Kansas City, Kansas terminal and a release that occurred in the first quarter of 2006 from our petroleum products pipeline near Independence, Kansas. Our accrual includes these additional releases. We are in ongoing negotiations with the EPA; 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.

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 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.

PCB Impacts. We have identified polychlorinated biphenyls (PCB) impacts at two of our petroleum products terminals that we are in the process of assessing. It is possible that in the near term the PCB contamination levels could require corrective actions. We are unable at this time to determine what the corrective actions and associated costs might be. The costs of any corrective actions associated with these PCB impacts could be material to our results of operations and cash flows.

Indemnification Settlement. Prior to May 2004, a former affiliate had agreed to indemnify us against, among other things, certain environmental losses associated with assets contributed to us at the time of our initial public offering or which we subsequently acquired from this former affiliate. In May 2004, our general partner entered into an agreement under which our former affiliate agreed to pay us $117.5 million to release it from these indemnifications. On June 29, 2007, we received the final $35.0 million installment payment associated with this agreement, which we recorded as a capital contribution. While the settlement agreement releases our former affiliate from its environmental and certain other indemnifications, some indemnifications remain in effect. These remaining indemnifications cover issues involving employee benefits matters, rights-of-way, easements and real property, including asset titles, and unlimited losses and damages related to tax liabilities.

At December 31, 2006 and December 31, 2007, known liabilities that would have been covered by this indemnity agreement were $45.7 million and $42.9 million, respectively. Through December 31, 2007, we have spent $45.5 million of the $117.5 million indemnification settlement amount for indemnified matters, including $20.1 million of capital costs. The cash we have received from the indemnity settlement is not reserved and has been used for our various other cash needs, including expansion capital spending.

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Environmental Receivables. Receivables from insurance carriers and other entities related to environmental matters were $5.9 million and $6.9 million at December 31, 2006 and December 31, 2007, respectively.

Unrecognized Product Gains. Our petroleum products terminals operations generate product overages and shortages. 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 combined net unrecognized product overages for our petroleum products terminals operations had a market value of approximately $11.1 million as of December 31, 2007. 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 future financial position, results of operations or cash flows.

18. Quarterly Financial Data (unaudited)

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

2006	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
Revenues	$ 279,260	$ 311,533	$ 316,637	$ 316,130
Operating margin	92,999	102,577	76,659	104,782
Total costs and expenses	217,208	240,995	273,016	246,612
Net income	48,313	57,370	30,593	56,452
Basic net income per limited partner unit	0.55	0.62	0.43	0.64
Diluted net income per limited partner unit	0.55	0.62	0.43	0.64
2007				
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

Revenues and operating margin were favorably impacted in all quarters during 2007 by increases in tariff rates and from capital projects completed in 2006 and early 2007. Product price increases during 2007 favorably impacted commodity revenues and margins and net product overages for all quarters during 2007. Second-quarter 2007 net income was negatively impacted $2.9 million by transactions associated with the repayment of our pipeline notes. Fourth-quarter 2007 revenues and operating margin were favorably impacted by $2.8 million from the revenues recognized from our variable-rate terminalling agreements.

Third-quarter 2006 operating margin was negatively impacted by lower product margins as a result of rapidly declining petroleum product prices. First-quarter 2006 and fourth-quarter 2006 revenues were favorably impacted by $6.4 million and $3.0 million, respectively, associated with the revenues we recognized from our variable-rate terminalling agreements.

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19. 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 and restricted cash. The carrying amounts reported in the balance sheet approximate fair value due to the short-term maturity or variable rates of these instruments.

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

Debt. The fair value of our publicly traded notes was based on the prices of those notes at December 31, 2006 and 2007. The fair value of our Magellan Pipeline notes was determined by discounting estimated future cash flows using our incremental borrowing rate. The carrying amount of floating-rate borrowings at December 31, 2007 approximates fair value due to the variable rates of those instruments.

Interest rate swaps. Fair value was determined based on forward market prices and approximates the net gains and losses that would have been realized if the contracts had been settled at each year-end. The 2006 values represent long-term liabilities and the 2007 values represent long-term assets.

Other deferred liabilities deposits. This liability represents a long-term deposit we hold associated with our third-party supply agreement. 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, 2006 and 2007 (in thousands):

	December 31, 2006		December 31, 2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 6,390	$ 6,390	$	$
Restricted cash	5,283	5,283		
Long-term receivables	6,920	6,526	7,506	6,849
Debt	792,383	800,385	911,801	933,650
Interest rate swaps	(2,935)	(2,935)	2,735	2,735
Other deferred liabilities deposits	13,500	7,042	18,500	9,886

Fair Value Measurements

In September 2006, the FASB adopted SFAS No. 157, *Fair Value Measurements*. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years; however, earlier application was encouraged. We elected to adopt SFAS No. 157 effective January 1, 2007. Our fair value measurements as of December 31, 2007 using significant other observable inputs for interest rate swap derivatives were $2.7 million.

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

20. Distributions

We paid the following distributions during 2005, 2006 and 2007 (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
02/14/05	$ 0.45625	$ 26,390	$ 3,887	$ 5,201	$ 35,478
05/13/05	0.48000	29,127	2,726	6,778	38,631
08/12/05	0.49750	30,189	2,825	7,939	40,953
11/14/05	0.53125	32,236	3,018	10,178	45,432
Total	$ 1.96500	$ 117,942	$ 12,456	$ 30,096	$ 160,494
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

(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 14, 2008, we paid cash distributions of $0.6575 per unit on our outstanding limited partner units to unitholders of record at the close of business on February 6, 2008. Because we issued 197,433 limited partner units in January 2008 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 1.995% to 1.989%. See Note 23 Subsequent Events for further discussion of this matter. The total distributions paid on February 14, 2008 were $63.8 million, of which $1.3 million was paid to our general partner on its 1.989% general partner interest and $18.6 million on its incentive distribution rights.

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

21. 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, 2005		
	Income (Numerator)	Units (Denominator)	Per Unit Amount
Limited partners interest in income	$ 135,579		
Basic net income per limited partner unit	$ 135,579	66,361	$ 2.04
Effect of dilutive restrictive unit grants		264	(.01)
Diluted net income per limited partner unit	$ 135,579	66,625	$ 2.03

	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

Units reported as dilutive securities are related to restricted unit grants associated with unvested awards (see Note 15 Long-Term Incentive Plan).

22. Partners Capital

Units outstanding. The following table details the changes in the number of our units outstanding and their ownership by affiliates and non-affiliates (the public) from January 1, 2005 through December 31, 2007.

	Common		Subordinated		
	Public	Affiliates	Public	Affiliates	Total
Units outstanding on January 1, 2005	52,370,000	5,471,082		8,519,542	66,360,624
01/05 Sale of units by affiliate	5,471,082	(5,471,082)			
02/05 Conversion of subordinated units to common units		2,839,846		(2,839,846)	
02/05 Sale of units by affiliate	450,288	(450,288)			
04/05 Sale of units by affiliate			5,679,696	(5,679,696)	
05/05 Sale of units by affiliate	2,100,000	(2,100,000)			

06/05 Sale of units by affiliate	289,558	(289,558)		
Units outstanding on December 31, 2005	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	768			768
Units outstanding on December 31, 2007[b]	66,546,297			66,546,297

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(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 year ended December 31, 2007, 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.

At December 31, 2007, all of our 66,546,297 limited partner units outstanding were held by the public and our approximate 2% general partner interest was owned by MGG.

The 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 26, 2007 until January 25, 2008, 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	98.005%	1.995%	0.000%
Above $0.289 up to $0.328	85.005%	1.995%	13.000%
Above $0.328 up to $0.394	75.005%	1.995%	23.000%
Above $0.394	50.005%	1.995%	48.000%

See Note 23 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, 2007.

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

Other changes in capital. Capital contributions were $20.1 million, $28.7 million and $40.2 million during 2005, 2006 and 2007, respectively, which primarily consisted of payments we received under the May 2004 indemnity settlement and amounts we received from MGG under the G&A cost cap agreement.

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

23. Subsequent Events

On January 24, 2008, our Compensation Committee approved 199,542 unit award grants pursuant to the long-term incentive plan, of which 184,051 have been granted to date. These award grants have a three-year vesting period that will end on December 31, 2010.

On January 24, 2008, we issued 197,433 limited partner units, of which 196,856 were issued to settle the 2005 unit award grants to certain employees, which vested on December 31, 2007, and 577 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 1.995% to 1.989%. Our general partner s incentive distribution rights were not affected by this transaction. As a result, cash distributions paid after January 24, 2008 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	98.011%	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%

During January 2008, we acquired a petroleum products terminal in Bettendorf, Iowa from CITGO Petroleum Corporation for $12.0 million. We have subsequently leased the Bettendorf terminal to a third-party entity under a long-term lease that has an initial term of five years.

Also during 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 a portion of borrowings under our revolving credit facility. We anticipate refinancing up to $250.0 million of our revolver borrowings with either new variable-rate debt or with ten-year fixed-rate debt by the end of the second quarter of 2008. Our objective is to limit our exposure to changes in the benchmark interest rate between now and the date of the refinancing. We will account for the interest rate swap agreements as a cash flow hedge.

On February 14, 2008. we paid cash distributions of $0.6575 per unit on our outstanding limited partner units to unitholders of record at the close of business on February 6, 2008. The total distributions paid were $63.8 million, of which $1.3 million was paid to our general partner on its approximate 2% general partner interest and $18.6 million on its incentive distribution rights.

During February 2008, we entered into an agreement to assign our third-party supply obligation to a third-party entity effective March 1, 2008. We will continue to earn transportation revenues for the product we ship related to this supply agreement but will no longer recognize associated product sales and purchases. We will share in a portion of the assignor s trading profits or losses relating to the assigned product supply agreement, but we will not be required to hold inventories. As of December 31, 2007, we held inventory valued at $49.3 million for the third-party supply agreement. Upon the March 1, 2008 effective date, we will sell any remaining inventory to the assignor and recognize the resulting gain or loss based on inventory values on that date. In the event the third-party entity assuming this obligation from us is unable to perform on this agreement through the 2018 expiration date, the supply agreement obligation will revert back to us.

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 and Exchange Act) during the quarter ended December 31, 2007 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 and 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:

Names and Business Experience of the Class III Nominees and Other Directors;

Executive Officers of our General Partner;

Compliance with Section 16(a) of the Exchange Act;

Code of Ethics; and

Our General Partner s Board of Directors and its 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:

Executive Compensation;

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 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:

Certain Relationships and Related Transactions; and

Our General Partner s Board of Directors and its Committees.

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

Exhibit No.	Description
Exhibit 2	
*(a)	Purchase Agreement dated April 18, 2003 among Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc., Williams GP LLC and WEG Acquisitions, L.P. (filed as Exhibit 99.1 to Form 8-K of The Williams Companies, Inc. filed April 21, 2003).
*(b)	Amendment No. 1 dated May 5, 2003 to Purchase Agreement dated April 18, 2003 among Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc., Williams GP LLC and WEG Acquisitions, L.P. (filed as Exhibit 99.2 to Schedule 13D/A filed June 20, 2003).
*(c)	Amendment No. 2 dated January 6, 2004 to Purchase Agreement dated April 18, 2003 among Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc., Williams GP LLC and WEG Acquisitions, L.P. (filed as Exhibit 2(c) to Form 10-K filed March 10, 2004).
*(d)	Amendment No. 3 dated May 26, 2004 to Purchase Agreement dated April 18, 2003 among Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc., Williams GP LLC and WEG Acquisitions, L.P. (filed as Exhibit 2.1 to Form 10-Q filed August 6, 2004).
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).
*(c)	Amendment No. 1 dated February 15, 2006 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 February 15, 2006).
*(d)	Amendment No. 2 dated February 9, 2006 to Fourth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated as of April 13, 2005 (filed as Exhibit 3.2 to Form 8-K filed February 15, 2006).

Exhibit No.	Description
*(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)	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).
*(g)	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).
*(h)	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 4	
*(a)	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).
*(b)	Amendment No. 1 dated February 15, 2006 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 February 15, 2006).
*(c)	Amendment No. 2 dated February 9, 2006 to Fourth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated as of April 13, 2005 (filed as Exhibit 3.2 to Form 8-K filed February 15, 2006).
*(d)	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).
*(e)	Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed May 25, 2004).
*(f)	First Supplemental Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.2 to Form 8-K filed May 25, 2004).
*(g)	Second Supplemental Indenture dated as of October 15, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed October 15, 2004).
*(h)	Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed April 20, 2007).
*(i)	First Supplemental Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed April 20, 2007).
Exhibit 10	
*(a)	Seventh Amended and Restated Magellan Midstream Partners Long-Term Incentive Plan effective October 26, 2006 (filed as Exhibit 10.1 to Form 8-K filed October 27, 2006).
*(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 2008 Annual Incentive Program.
(d)	Form of 2008 Phantom Unit Award Agreement pursuant to the Magellan Midstream Partners Long-Term Incentive Plan.
*(e)	Summary of Independent Director Compensation Program (filed as Exhibit 10.1 to Form 8-K/A filed February 3, 2005).

Exhibit No.	Description
*(f)	Director Deferred Compensation Plan effective October 1, 2006 (filed as Exhibit 10.1 to Form 8-K filed October 4, 2006).
*(g)	New Omnibus Agreement dated June 17, 2003 among WEG Acquisitions, L.P., Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc. and The Williams Companies, Inc. (filed as Exhibit 10.3 to Form 8-K filed June 17, 2003).
*(h)	Services Agreement dated December 24, 2005 between Magellan Midstream Partners, L.P. and Magellan Midstream Holdings GP, LLC (filed as Exhibit 10.1 to Form 8-K filed December 27, 2005).
*(i)	$550,000,000 Second Amended and Restated Credit Agreement dated as of September 20, 2007 among Magellan Midstream Partners, L.P., as Borrower, the Lenders party thereto and Wachovia Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to Form 8-K filed September 21, 2007).
*(j)	Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed May 25, 2004).
*(k)	First Supplemental Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.2 to Form 8-K filed May 25, 2004).
*(l)	Second Supplemental Indenture dated as of October 15, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed October 15, 2004).
*(m)	Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed April 20, 2007).
*(n)	First Supplemental Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed April 20, 2007).
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	
(a)	Certification of Don R. Wellendorf, principal executive officer.
(b)	Certification of John D. Chandler, principal financial officer.
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, 2007 and 2006 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 28, 2008

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 28, 2008
/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 28, 2008
/s/ JOHN P. DESBARRES **John P. DesBarres**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 28, 2008
/s/ PATRICK C. EILERS **Patrick C. Eilers**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 28, 2008
/s/ THOMAS T. MACEJKO,JR. **Thomas T. Macejko, Jr.**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 28, 2008
/s/ JAMES R. MONTAGUE **James R. Montague**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 28, 2008
/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 28, 2008
/s/ THOMAS S. SOULELES **Thomas S. Souleles**	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 28, 2008

INDEX TO EXHIBITS

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Exhibit 2	
*(a)	Purchase Agreement dated April 18, 2003 among Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc., Williams GP LLC and WEG Acquisitions, L.P. (filed as Exhibit 99.1 to Form 8-K of The Williams Companies, Inc. filed April 21, 2003).
*(b)	Amendment No. 1 dated May 5, 2003 to Purchase Agreement dated April 18, 2003 among Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc., Williams GP LLC and WEG Acquisitions, L.P. (filed as Exhibit 99.2 to Schedule 13D/A filed June 20, 2003).
*(c)	Amendment No. 2 dated January 6, 2004 to Purchase Agreement dated April 18, 2003 among Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc., Williams GP LLC and WEG Acquisitions, L.P. (filed as Exhibit 2(c) to Form 10-K filed March 10, 2004).
*(d)	Amendment No. 3 dated May 26, 2004 to Purchase Agreement dated April 18, 2003 among Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc., Williams GP LLC and WEG Acquisitions, L.P. (filed as Exhibit 2.1 to Form 10-Q filed August 6, 2004).
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).
*(c)	Amendment No. 1 dated February 15, 2006 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 February 15, 2006).
*(d)	Amendment No. 2 dated February 9, 2006 to Fourth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated as of April 13, 2005 (filed as Exhibit 3.2 to Form 8-K filed February 15, 2006).
*(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)	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).
*(g)	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).
*(h)	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 4	
*(a)	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).
*(b)	Amendment No. 1 dated February 15, 2006 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 February 15, 2006).

Exhibit No.	Description
*(c)	Amendment No. 2 dated February 9, 2006 to Fourth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated as of April 13, 2005 (filed as Exhibit 3.2 to Form 8-K filed February 15, 2006).
*(d)	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).
*(e)	Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed May 25, 2004).
*(f)	First Supplemental Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.2 to Form 8-K filed May 25, 2004).
*(g)	Second Supplemental Indenture dated as of October 15, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed October 15, 2004).
*(h)	Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed April 20, 2007).
*(i)	First Supplemental Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed April 20, 2007).
Exhibit 10	
*(a)	Seventh Amended and Restated Magellan Midstream Partners Long-Term Incentive Plan effective October 26, 2006 (filed as Exhibit 10.1 to Form 8-K filed October 27, 2006).
*(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 2008 Annual Incentive Program.
(d)	Form of 2008 Phantom Unit Award Agreement pursuant to the Magellan Midstream Partners Long-Term Incentive Plan.
*(e)	Summary of Independent Director Compensation Program (filed as Exhibit 10.1 to Form 8-K/A filed February 3, 2005).
*(f)	Director Deferred Compensation Plan effective October 1, 2006 (filed as Exhibit 10.1 to Form 8-K filed October 4, 2006).
*(g)	New Omnibus Agreement dated June 17, 2003 among WEG Acquisitions, L.P., Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc. and The Williams Companies, Inc. (filed as Exhibit 10.3 to Form 8-K filed June 17, 2003).
*(h)	Services Agreement dated December 24, 2005 between Magellan Midstream Partners, L.P. and Magellan Midstream Holdings GP, LLC (filed as Exhibit 10.1 to Form 8-K filed December 27, 2005).
*(i)	$550,000,000 Second Amended and Restated Credit Agreement dated as of September 20, 2007 among Magellan Midstream Partners, L.P., as Borrower, the Lenders party thereto and Wachovia Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to Form 8-K filed September 21, 2007).
*(j)	Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed May 25, 2004).

Exhibit No.	Description
*(k)	First Supplemental Indenture dated as of May 25, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.2 to Form 8-K filed May 25, 2004).
*(l)	Second Supplemental Indenture dated as of October 15, 2004 between Magellan Midstream Partners, L.P. and SunTrust Bank, as trustee (filed as Exhibit 4.1 to Form 8-K filed October 15, 2004).
*(m)	Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed April 20, 2007).
*(n)	First Supplemental Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed April 20, 2007).
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	
(a)	Certification of Don R. Wellendorf, principal executive officer.
(b)	Certification of John D. Chandler, principal financial officer.
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, 2007 and 2006 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.