MAGELLAN MIDSTREAM PARTNERS LP
Form 10-K
February 28, 2007

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, 2006
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 or a non-accelerated filer.

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

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, 2006 was $2,250,606,888.

As of February 27, 2007, there were 66,546,297 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 2007 Annual Meeting of Limited Partners are incorporated by reference in Part III of this Form 10-K.

MAGELLAN MIDSTREAM PARTNERS, L.P.

FORM 10-K

PART I

ITEM 1. ***Business***

(a) General Development of Business

We were formed as a limited partnership under the laws of the State of Delaware in August 2000. Our common units representing limited partner interests in us (limited partner units) trade on the New York Stock Exchange under the symbol MMP. Our general partner is Magellan GP, LLC, a Delaware limited liability company. Magellan Midstream Holdings, L.P. (NYSE: MGG) has been the owner of our general partner since June 2003.

(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, 2006, our asset portfolio consists of:

- an 8,500-mile petroleum products pipeline system, including 45 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;
- 29 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 # 6 fuel oil and vacuum gas oil; and

crude oil and condensate, which are used as feedstocks by refineries.

The Gulf Coast region is a significant supply source for our facilities and is a major hub for petroleum refining. According to the Petroleum Supply Annual for 2005 published by the Energy Information Administration (EIA), the Gulf Coast region accounted for approximately 41% of total U.S. daily refining capacity and 64% of U.S. refining capacity expansion from 1999 to 2005. 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 and Illinois. Our pipeline system transports petroleum products and LPGs and includes 45 terminals. The products transported on our pipeline system are largely transportation fuels, and in 2006 were comprised of 53% gasoline, 37% distillates (which include diesel fuels and heating oil) and 10% LPGs and aviation fuel. 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 83%, 89% and 86% of our consolidated total revenues in 2004, 2005 and 2006, respectively. See Note 17 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 it serves through their shipments on our pipeline system. According to statistics provided by the EIA, the demand for refined petroleum products in the primary market areas served by our petroleum products pipeline system, known as Petroleum Administration for Defense District (PADD) II, is expected to grow at an average rate of approximately 1.3% per year over the next 10 years. The total production of refined petroleum products from refineries located in PADD II is currently insufficient to meet the demand for refined petroleum products in PADD II. The excess PADD II 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 PADD III, which represents the Gulf Coast region, and, to a lesser degree, from expansion of PADD II refineries.

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, CITGO and Seaway/ConocoPhillips pipelines. These connections to Gulf Coast refineries, together with our pipeline s extensive network throughout PADD II and connections to PADD II 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 18% from 2004 to 2006. These volume increases are a result of our October 2004 petroleum products pipeline system acquisition as well as 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:

	2004	2005	2006
Shipments (thousands of barrels):			
Refined products			
Gasoline	140,320	161,204	164,548
Distillates	89,614	106,137	113,217
Aviation fuel	16,709	21,792	21,100
LPGs	8,385	8,520	9,812
Total product shipments	255,028	297,653	308,677
Capacity leases	25,324	25,234	21,605
Total shipments, including capacity leases	280,352	322,887	330,282
Daily average (thousands of barrels)	766	885	905

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 2006, our petroleum products pipeline system generated 79% 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 45 terminals. Revenues from terminalling and storage at our other seven terminals are at privately negotiated rates.

In 2006, our petroleum products pipeline system generated the remaining 21% 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 pipelines for others. In January 2004, we began serving as a subcontractor for the operation of Longhorn Partners Pipeline, L.P. and in April 2005 we took over as operator. In March 2004 we began operating the Osage Pipeline system.

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 $265.0 million, $625.7 million and $643.6 million in 2004, 2005 and 2006, respectively, the difference between product sales and product purchases, which we believe better represents the importance of these activities, was $15.9 million, $46.9 million and $50.0 million in 2004, 2005 and 2006, respectively, as product purchases were $249.1 million, $578.8 million and $593.6 million in 2004, 2005 and 2006, respectively.

Facilities. Our petroleum products pipeline system consists of an 8,500-mile pipeline with 45 terminals and includes more than 27.0 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 2006, 53% of the petroleum products transported on our petroleum products pipeline system originated from 11 direct refinery connections and 47% 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 Corporation	El Dorado, KS
Gary Williams Energy Corporation	Wynnewood, OK
Marathon Ashland Petroleum Company	St. Paul, MN
Murphy Oil USA, Inc.	Superior, WI
National Cooperative Refining Association	McPherson, KS
Sinclair Oil Corporation	Tulsa, OK
Sunoco, Inc.	Tulsa, OK
Valero Energy Corporation	Ardmore, OK

The most significant of our pipeline connections is to 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
CITGO	Drumright, OK	Various Gulf Coast refineries
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
Kinder Morgan	Plattsburg, MO; Des Moines, IA; Wayne, IL	Bushton, KS storage and Chicago, IL area refineries
Mid-America (Enterprise)	El Dorado, KS	Conway, KS storage
Sinco	East Houston, TX	Deer Park, TX refinery
Valero, L.P.	El Dorado, KS; Minneapolis, MN; Wynnewood, OK	Various OK & KS refineries and Mandan, ND 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 57% of the shipments in 2006 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, 2006, our petroleum products pipeline system had approximately 50 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, 2006 represented 34% of total revenues for our petroleum products pipeline system and 52% 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.

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.

In 2007, government mandates will require fuel marketers in the United States to blend up to 4.7 billion gallons of renewable fuels (primarily ethanol), growing to 7.5 billion gallons by 2012. Furthermore, federal legislators are evaluating increasing these requirements. 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, with a majority of the ethanol being shipped by railroad or truck. The increased use of ethanol has and will continue to compete with shipments on pipeline systems. However, terminals on pipeline systems, including ours, 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 while also producing an attractive return on the investments made in blending infrastructure.

PETROLEUM PRODUCTS TERMINALS

Within our petroleum products terminals network, we operate two types of terminals: marine terminals and inland terminals. Our marine terminals are located in close proximity to refineries and are large storage and distribution facilities that handle refined petroleum products, blendstocks, ethanol, heavy oils, feedstocks, crude oil and condensate. Our inland terminals are primarily located in the southeastern United States along third-party pipelines such as those operated by Colonial Pipeline Company (Colonial), Explorer Pipeline Company (Explorer), Plantation Pipe Line Company (Plantation) and TEPPCO Partners, L.P. (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 15%, 10% and 13% of our consolidated total revenues in 2004, 2005 and 2006, respectively. See Note 17 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 22.0 million barrels, which provide inventory management, storage and distribution 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 2006, approximately 97% of our marine terminal capacity was utilized. As of December 31, 2006, approximately 90% of our usable storage capacity was under long-term contracts with remaining terms in excess of one year or that renew on an annual basis. We have entered into two storage agreements pursuant to which we receive 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 29 refined petroleum products terminals located primarily in the southeastern United States. We wholly own 26 of the 29 terminals in our portfolio. Our terminals have a combined capacity of almost 6.0 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. During 2006, gasoline represented approximately 58% of the product volume distributed through our inland terminals, with the remaining 42% consisting of distillates.

Our inland terminals typically consist of multiple storage tanks that are connected to a third-party pipeline system. 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.

We are an independent provider of storage and distribution services. We operate our inland terminals as distribution terminals and we primarily serve 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. Ammonia is the primary feedstock for the production of upgraded nitrogen fertilizers and chemicals. The ammonia pipeline system segment accounted for 2% of our consolidated revenues in 2004 and 1% in both 2005 and 2006. See Note 17 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 provides the operating services and a portion of the general and administrative services for our ammonia pipeline system under an operating agreement with us.

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. 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, 2006 through June 30, 2007 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 Valero L.P., which originates on the Gulf Coast and transports domestically produced and imported ammonia.

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 are customers of both our petroleum products pipeline system and petroleum products terminals segments. Customer A purchased petroleum products from us pursuant to a third-party supply agreement we assumed in connection with our pipeline system acquisition in October 2004. In August 2006, this third-party supply agreement was assigned to Customer B. No other customer accounted for more than 10% of our consolidated total revenues for 2004, 2005 or 2006. 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.

	2004	**2005**	**2006**
Customer A	13%	42%	29%
Customer B	0%	0%	18%
Customer C	19%	9%	11%
Total	32%	51%	58%

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 in its initial form allowed a pipeline to change its rates based on the annual change in the producer price index for finished goods (PPI-FG) less 1%. As required by its own regulations, the FERC must review the index methodology every five years to determine if the then current index is still appropriate or if the index should be adjusted. After the first five year period, the FERC changed the rate indexing methodology to the PPI-FG, but without the subtraction of 1% as had been done previously. In 2006, at the end of the second five-year period, the FERC again changed the index methodology. The index for the current five-year period is set at 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 a shipper 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 July 2004, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued its opinion in *BP West Coast Products, LLC v. FERC*, which upheld, among other things, the FERC s determination that certain rates of an interstate petroleum products pipeline, SFPP, L.P. (SFPP), were grandfathered rates under the Energy Policy Act of 1992 and that SFPP s shippers had not demonstrated substantially changed circumstances that would justify modification of those rates. The court also vacated the portion of the FERC s decision applying the *Lakehead* policy. In the *Lakehead* decision, the FERC allowed an oil pipeline publicly traded partnership to include in its cost-of-service an income tax allowance to the extent that its unitholders were corporations subject to income tax. In May and June 2005, the FERC issued a statement of general policy, as well as an order on remand of *BP West Coast*, respectively, in which the FERC stated it will permit pipelines to include in cost of service a tax allowance to reflect actual or potential tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such 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 are 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 in the SFPP proceeding, reaffirming its new income tax allowance policy and directing SFPP to provide certain evidence necessary for the pipeline to determine its income tax allowance. Further, in the December 2005 order, the FERC concluded that for tax allowance purposes, the FERC would apply a rebuttable presumption that corporate partners of pass-through entities pay the maximum marginal tax rate of 35% and that non-corporate partners of pass-through entities pay a marginal rate of 28%. The FERC indicated that it would address the income tax allowance issues further in the context of SFPP s compliance submitted in March 2006. In December 2006, the FERC ruled on some of the issues raised as to the March 2006 SFPP compliance filing, upholding most of its determinations in the December 2005 order. The FERC did revise its rebuttable presumption as to corporate partners marginal tax rate from 35% to 34%. The FERC s *BP West Coast* remand decision, the new tax allowance policy and the December 2005 order have been appealed to the D.C. Circuit. Oral argument was held in December 2006. As a result, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC s treatment of income tax allowances in cost of service.

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 holds market power, then we may be required to show that our 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.

In December 2000, the Department of Transportation adopted new regulations requiring 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. We expect to complete the initial assessments by the March 2008 deadline. The regulations also require ongoing reassessments.

In 2003, the seller of the pipeline and terminal assets we acquired in October 2004 entered into a consent decree with the Environmental Protection Agency (EPA) arising out of a June 1999 incident unrelated to the assets we acquired. In order to resolve its civil liability for the incident, the seller agreed to pay civil penalties and to comply with certain terms set out in the consent decree. These terms include requirements for testing and maintenance of a number of the seller s pipelines, including certain of the pipelines we acquired, the creation of a damage prevention program, submission to independent monitoring and various reporting requirements. The consent decree extends until 2008. Under our purchase agreement, we agreed, at our own expense, to complete any remaining remediation work required under the consent decree with respect to these pipelines and assumed a liability of approximately $8.6 million at the time of the acquisition for this remediation work. As of December 31, 2006, this liability was $2.4 million. The seller has retained responsibility to the EPA for compliance with the terms of the consent decree.

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 $58.2 million and $57.8 million at December 31, 2005 and 2006, respectively. Environmental liabilities have been classified as current or noncurrent based on scheduled payments for certain of our environmental liabilities and management s estimates regarding the timing of actual payments for all other environmental liabilities. Management estimates that expenditures associated with these environmental remediation liabilities will be paid over the next ten years.

During the third quarter of 2006, we entered into a risk transfer agreement with a contractor pursuant to which the contractor assumed the responsibility for the remediation of certain of our environmental sites in exchange for $14.0 million to be paid over the next 10 years. Further, the agreement required the contractor to purchase a cost cap insurance policy, under which we are an additional named insured party. The cost of this policy was $2.2 million, which we were required to pay. At the time we entered into this agreement, we adjusted our environmental liabilities associated with these sites to $11.9 million, which represented the discounted amount of the cash payments to be made to this contractor. That adjustment resulted in our recognizing environmental expense of $2.9 million, which, when combined with the $2.2 million of expense recognized associated with the cost cap insurance policy, resulted in our recognizing $5.1 million of environmental expense in the third quarter of 2006. We discounted this liability as the amount and timing of cash payments to be made are reliably determinable. The liability estimates for all of our other environmental sites are provided on an undiscounted basis.

In July 2001, the EPA, pursuant to Section 308 of the Clean Water Act (the Act) served an information request to a former affiliate with regards to petroleum discharges from its pipeline operations. That inquiry primarily focused on Magellan Pipeline Company, L.P. (Magellan Pipeline), which 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 assumes that all releases were 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 (SPCC) 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 that is less than $22.0 million associated with this matter. Most of the amounts we have accrued for this matter were included as part of the environmental indemnification settlement we reached with our former affiliate (see Note 18 Commitments and Contingencies in the accompanying consolidated financial statements). Due to the uncertainties described above, it is reasonably possible that the amounts we have recorded for this environmental liability could change in the near term. Management is in ongoing discussions with the EPA, however, we are unable to determine with any accuracy what our ultimate liability could be for this matter. Adjustments from amounts we currently have recorded to the final settlement amounts reached with the EPA could be material to our results of operations and cash flows.

During the second quarter of 2005, we experienced a line break and release of approximately 2,900 barrels of product on our petroleum products pipeline near our Kansas City, Kansas terminal. As of December 31, 2006, we have estimated costs associated with this release of approximately $2.8 million. Through December 31, 2006, we have spent $1.9 million on remediation associated with this release and as of December 31, 2006 have recorded associated environmental liabilities of $0.9 million. We have recognized a receivable of $1.2 million from our insurance carrier for this matter. We will include this release with the 32 other releases discussed above in negotiating any penalties or other injunctive relief that might be assessed.

During the first quarter of 2006, we experienced a line break and release of approximately 3,200 barrels of product on our petroleum products pipeline near Independence, Kansas. As of December 31, 2006, we have estimated remediation costs associated with this release of approximately $5.0 million. Through December 31, 2006, we have spent $3.0 million on remediation associated with this release and, as of December 31, 2006, have recorded associated environmental liabilities of $2.0 million and a receivable of $3.5 million from our insurance carrier for this matter. We will include this release with the 32 other releases discussed above in negotiating any penalties or other injunctive relief that might be assessed.

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 was liable for penalties pursuant to Section 103 of the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) for failing to timely report the releases and that the statutory maximum for those penalties could be as high as $4.2 million. We are evaluating whether or not we have an indemnity obligation to the third party operator for all or a portion of the CERCLA penalties. Additionally, 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 and that it may seek injunctive relief if the parties cannot agree on any necessary corrective actions. We are currently in discussions with the EPA and DOJ regarding these two releases; however, we do not believe that the ultimate resolution of this matter will have a material impact on our results of operations, financial position or cash flows.

Environmental Indemnification Settlement. Prior to May 2004, The Williams Companies, Inc. (Williams), a former affiliate of ours, had agreed to indemnify us against certain environmental losses, among other things, associated with assets that Williams contributed to us at the time of our initial public offering or which we subsequently acquired from Williams. In May 2004, we and our general partner entered into an agreement with Williams under which Williams agreed to pay us $117.5 million to release it from these indemnifications. Pursuant to this agreement, we received $35.0 million, $27.5 million and $20.0 million on July 1, 2004, 2005 and 2006, respectively, and we expect to receive the final installment payment of $35.0 million on July 1, 2007.

As of December 31, 2005 and 2006, known liabilities that would have been covered by the aforementioned indemnity agreements were $43.1 million and $45.7 million, respectively. Through December 31, 2006, we have spent $31.7 million of the $117.5 million indemnification settlement amount for indemnified matters, including $13.4 million of capital costs. The cash we have received from the indemnity settlement was not reserved and has been used by us for various other cash needs, including expansion capital spending.

Environmental Receivables. In June 2003, concurrent with its acquisition of limited and general partner interests in us, MGG agreed to assume obligations for $21.9 million of our environmental liabilities. As of December 31, 2006, all of these obligations have been paid by MGG.

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 do not hold ourselves out as 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 have been 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. Although potential costs associated with the removal or remediation of previously disposed wastes are unknown, we do not expect these potential costs to have a material adverse effect on our results of operations, financial position or cash flows.

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 one of our petroleum products terminals that we are in the process of delineating. It is possible that in the near term after our delineation 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.

Natural Resource Damages. As a result of an ammonia pipeline release that occurred in October 2004, the Kansas Department of Health and Environment (KDHE), acting as the natural resource trustee under federal law and in cooperation with the United States Fish and Wildlife Services, presented a claim to us for natural resource damages. The principal concern was the impact the release had on the Arkansas darter, a small fish protected as a threatened species under Kansas law. The KDHE has tentatively approved our proposal to acquire a conservation easement as settlement for the natural resource related damages. The estimated cost for the project is $0.5 million.

Above Ground Storage Tanks. Many of our above ground storage tanks containing liquid substances are required under federal 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 $5.0 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 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, as amended and comparable state and local laws. Under such laws, permits are typically required to emit pollutants into the atmosphere. Pursuant to the Clean Air Act and a 2003 consent decree, the EPA has issued a Notice of Proposed Rulemaking relating to certain gasoline distribution facilities that is generally known as the Generally Available Control Technology Rule for Area Sources. A final regulation is anticipated in December 2007. We are currently in the process of assessing the impact the proposed regulation could have on our facilities. If the final rule is passed as currently drafted, the regulation could require us to invest significant capital to meet the new compliance rules. Once the regulation and related cost estimates are finalized, we will assess whether we can justify the cost to convert the various facilities or whether we should close the impacted locations. The proposed rule also is expected to affect industries other than gasoline distribution terminals, and we are working with the petroleum industry to provide extensive comments to the EPA regarding the overall impact of the proposed rule. Under EPA and applicable state and local regulations, our facilities that emit volatile organic compounds or nitrogen oxides are subject to increasingly stringent regulations, including requirements that some sources install maximum achievable control technology or reasonably available control technology. In addition, the regulations include an operating permit for major sources of volatile organic compounds, which applies to some of our facilities. We believe that we currently hold or have applied for all necessary air permits.

Safety. Our assets are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes. The OSHA hazard communication standard and comparable state statutes require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to employees, state and local governmental authorities and local citizens upon request. At qualifying facilities, we are subject to OSHA Process Safety Management regulations that are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals.

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, 2006, MGG GP employed approximately 1,064 employees, of whom 569 were assigned to conduct the operations of our petroleum products pipeline system, 236 were assigned to conduct the operations of our petroleum products terminals and 259 were assigned to provide general and administrative (G&A) services.

(d) Financial Information About Geographical Areas

We have no revenue or segment profit or loss 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 2006.

ITEM 1A. *Risk Factors*

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 government mandated increase in the use of alternative fuel sources, such as biofuels, fuel cells and solar, electric and battery-powered engines.

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 financial position, results of operations 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 had agreements with a customer pursuant to which we charged 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, we recognized revenues of $9.4 million combined from two agreements, one of which expired January 31, 2006 and the other on December 31, 2006. We have negotiated a similar agreement pursuant to which we will receive a share of any net trading profits above a specified amount during 2007, 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 this agreement in 2007 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 by a percentage equal to the change in the PPI-FG to the new ceiling level. 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.

In July 2004, the D.C. Circuit issued its opinion in *BP West Coast Products, LLC v. FERC*, which upheld, among other things, the FERC s determination that certain rates of an interstate petroleum products pipeline, SFPP, were grandfathered rates under the Energy Policy Act of 1992 and that SFPP s shippers had not demonstrated substantially changed circumstances that would justify modification of those rates. The court also vacated the portion of the FERC s decision applying the *Lakehead* policy. In the *Lakehead* decision, the FERC allowed an oil pipeline publicly traded partnership to include in its cost-of-service an income tax allowance to the extent that its unitholders were corporations subject to income tax. In May and June 2005, the FERC issued a statement of general policy, as well as an order on remand of *BP West Coast*, respectively, in which the FERC stated it will permit pipelines to include in cost of service a tax allowance to reflect actual or potential tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such 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 are 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 in the SFPP proceeding, reaffirming its new income tax allowance policy and directing SFPP to provide certain evidence necessary for the pipeline to determine its income allowance. Further, in the December 2005 order, the FERC concluded that for tax allowance purposes, the FERC would apply a rebuttable presumption that corporate partners of pass-through entities pay the maximum marginal tax rate of 35% and that non-corporate partners of pass-through entities pay a marginal rate of 28%. The FERC indicated that it would address the income tax allowance issues further in the context of SFPP s compliance filing submitted in March 2006. In December 2006, the FERC ruled on some of the issues raised as to the March 2006 SFPP compliance filing, upholding most of its determinations in the December 2005 order. The FERC did revise its rebuttable presumption as to corporate partners marginal tax rate from 35% to 34%. The FERC s *BP West Coast* remand decision, the new tax allowance policy and the December 2005 order have been appealed to the D.C. Circuit. Oral argument was held in December 2006. As a result, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC s treatment of income tax allowances in cost of service.

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 successfully challenged, the FERC could take away our ability to establish market-based rates. We would then be required to establish rates that would be justified 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.

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/State civil and/or criminal penalties that could be material to our results of operations and cash flows.

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 flow 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 flow 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 could reduce our throughput volume, require us to incur additional handling costs or require capital expenditures. For instance, different product specifications for different markets impact the fungibility of the products in our system and could require the construction of additional storage. If we are unable to recover these costs through increased revenues, our cash flows and ability to pay cash distributions could be adversely affected. In addition, changes in the product quality of the products we receive on our petroleum products pipeline system could reduce or eliminate our ability to blend products.

Terrorist attacks aimed at our facilities 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.

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, 2006, we had fixed-rate debt of $772.6 million outstanding, excluding unaccreted discounts and fair value adjustments for interest rate hedges. We have effectively converted $350.0 million of this debt to floating-rate debt using interest rate swap agreements. In addition, we had $20.5 million of floating rate borrowings outstanding on our revolving credit facility as of December 31, 2006. As a result of these swap agreements and revolver borrowings, 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.

The terms of our indemnification settlement agreement require Williams to make a payment to us in July 2007, exposing us to credit risk.

In May 2004, we, MGG and our general partner entered into an agreement with Williams under which Williams agreed to pay us $117.5 million to release Williams from its environmental and certain other indemnification obligations to us, consisting primarily of costs related to environmental remediation matters related to assets that were contributed to us by Williams or which we acquired from Williams. Pursuant to this agreement, we have received $82.5 million as of December 31, 2006, and we expect to receive the remaining balance of $35.0 million in July of 2007. Williams credit ratings are below investment grade and its failure to perform on its payment obligations under the settlement agreement could adversely affect our ability to meet these obligations and pay cash distributions.

Restrictions contained in our debt instruments and the debt instruments of Magellan Pipeline may limit our financial flexibility.

We and our subsidiary, Magellan Pipeline, 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 or the debt of Magellan Pipeline 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 will reimburse our general partner and its affiliates, including officers and directors of our general partner, for expenses they incur on our behalf. The reimbursement of expenses 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, subject to certain annual limits. 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 Midstream Holdings, L.P. amounting to approximately 5% of its total ownership. MGG Midstream Holdings, L.P. currently owns the general partner interest and 65% of the 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 Buckeye Partners, L.P. (Buckeye), and the general partner of SemGroup, L.P. (SemGroup), both of which are engaged in the transportation, storage and distribution of refined petroleum products and may acquire other entities that compete with us. Although we do not have extensive operations in the geographic areas primarily served by Buckeye, we will compete directly with Buckeye, SemGroup and perhaps other entities in which CRF has an interest for acquisition opportunities throughout the United States and potentially will compete with Buckeye, SemGroup 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.

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 will be subject to a new entity level tax on the portion of our income that is generated in Texas beginning in 2007. Imposition of such a tax on us by Texas, or 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 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.

Our partnership will be considered to have been terminated for federal income tax purposes if, within a 12-month period, there is a sale or exchange of 50% or more of the total interests in our capital and profits. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income, resulting in more income being allocated to our unitholders during that tax year.

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.

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. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our limited partner units.

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***

In July 2001, the 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 Magellan Pipeline, which we subsequently acquired from the affiliate. 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 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 assumes 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 SPCC 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 that is less than $22.0 million.

Most of the amounts we have accrued for this matter were included as part of the environmental indemnification settlement we reached with our former affiliate (see Note 18 Commitments and Contingencies in the accompanying consolidated financial statements). Due to the uncertainties described above, it is reasonably possible that the amounts we have recorded for this environmental liability could change in the near term. Management is in ongoing discussions with the EPA; however, we are unable to determine what our ultimate liability could be for this matter. Adjustments from amounts we currently have recorded to the final settlement amounts reached with the EPA could be material to our results of operations and cash flows.

During the second quarter of 2005, we experienced a product release involving approximately 2,900 barrels of gasoline from our petroleum products pipeline near our Kansas City, Kansas terminal. Further, during the first quarter of 2006, we experienced a line break and release of approximately 3,200 barrels of product on our petroleum products pipeline near Independence, Kansas. Per discussions with the EPA and DOJ, we will include settlement of any alleged Section 308 violations associated with these two releases in conjunction with the 32 other releases discussed, including negotiating any penalties or other injunctive relief that might be assessed.

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 was liable for penalties pursuant to Section 103 of the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) for failing to timely report the releases and that the statutory maximum for those penalties could be as high as $4.2 million. We are evaluating whether or not we have an indemnity obligation to the third party operator for all or a portion of the CERCLA penalties. Additionally, 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 and that it may seek injunctive relief if the parties cannot agree on any necessary corrective actions. We are currently in discussions with the EPA and DOJ regarding these two releases; however, we do not believe that the ultimate resolution of this matter will have a material impact on our results of operations, financial position or cash flows.

We are also a party to various legal actions that have arisen in the ordinary course of our business. We do not believe that the resolution of these matters will have a material adverse effect on our financial condition or results of operations.

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 New York Stock Exchange under the ticker symbol MMP .

At the close of business on February 20, 2007, we had 243 registered holders and approximately 52,000 beneficial holders of record of our limited partner units. The high and low closing sales price ranges for and distributions paid on our limited partner units by quarter for 2005 and 2006 are as follows:

	2005			2006		
Quarter	**High**	**Low**	**Distribution***	**High**	**Low**	**Distribution***
1st	$ 31.50	$ 29.28	$ 0.48000	$ 33.27	$ 30.82	$ 0.56500
2nd	$ 33.01	$ 30.45	$ 0.49750	$ 35.20	$ 32.80	$ 0.57750
3rd	$ 35.30	$ 31.74	$ 0.53125	$ 36.93	$ 33.65	$ 0.59000
4th	$ 34.65	$ 31.75	$ 0.55250	$ 39.24	$ 36.85	$ 0.60250

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

In addition to common units, we also issued 11,359,388 subordinated units as part of our initial public offering. Because we exceeded certain cash distribution requirements identified in our partnership agreement, these subordinated units converted to an equal number of common units over the past three years, with the remaining 5,679,696 subordinated units converting to common units on January 31, 2006. Therefore, we no longer have subordinated units.

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. Until January 26, 2007, the percentage of distributions paid was 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%	2%	0%
Above $0.289 up to $0.328	85%	2%	13%
Above $0.328 up to $0.394	75%	2%	23%
Above $0.394	50%	2%	48%

On January 26, 2007, we issued 185,673 limited partner units primarily to settle award grants under our long-term incentive compensation plan that vested on December 31, 2006. Our general partner did not make an equity contribution associated with this equity issuance which resulted in its general partner ownership interest in us changing from 2.000% to 1.995%. As a result, cash distributions paid after January 26, 2007, 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	98.005%	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%

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 $0.6025 per limited partner unit, which entitles our general partner to receive approximately 29% of the total cash distributions paid. In general, we 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 December 31, 2001. 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), TEPPCO Partners, L.P. (NYSE: TPP) and Valero L.P. (NYSE: VLI).

	12/31/01	12/31/02	12/31/03	12/31/04	12/30/05	12/29/06
Magellan Midstream Partners, L.P.	100.0	83.5	138.1	173.0	202.0	258.4
Peer Index	100.0	96.3	139.9	144.1	150.1	177.9
S&P 500	100.0	78.0	100.3	111.2	116.6	135.0

Equity Compensation Plans

The information relating to our equity compensation plans required by Item 5 is incorporated by reference to information shown in Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters contained in this Annual Report on Form 10-K.

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. Due to the April 2002 acquisition of Magellan Pipeline, we adjusted our consolidated financial statements and notes to reflect the results of operations, financial position and cash flows of Magellan Midstream Partners, L.P. and Magellan Pipeline on a combined basis for 2002. This financial information is an integral part of, and should be read in conjunction with, the consolidated financial statements and notes thereto. All other amounts have been prepared from our financial records. 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 (see Note 6 Acquisitions in the accompanying consolidated financial statements), 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 18 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 premiums, write-off of unamortized debt placement fees, debt placement fee amortization, interest expense (net of interest income and capitalized interest) 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 17 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 G&A expenses, which management does not consider when evaluating the core profitability of an operation.

	Year Ended December 31, 2002	2003	2004	2005	2006
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenues	$ 363,740	$ 372,848	$ 419,117	$ 500,196	$ 558,301
Product sales revenues	70,527	112,312	275,769	636,209	664,569
Affiliate management fee revenues	210		488	667	690
Total revenues	434,477	485,160	695,374	1,137,072	1,223,560
Operating expenses	155,146	166,883	179,657	229,795	244,526
Product purchases	63,982	99,907	255,599	582,631	605,341
Equity earnings			(1,602)	(3,104)	(3,324)
Operating margin	215,349	218,370	261,720	327,750	377,017
Depreciation and amortization expense	35,096	36,081	41,845	56,307	60,852
Affiliate G&A expense	43,182	56,846	54,466	61,131	67,112
Operating profit	137,071	125,443	165,409	210,312	249,053
Interest expense, net	21,758	34,536	35,435	48,258	53,010
Debt prepayment premiums			12,666		
Write-off of unamortized debt placement costs			5,002		
Debt placement fee amortization	9,950	2,830	3,056	2,871	2,681
Other (income) expense, net	(2,112)	(92)	(953)	(300)	634
Income before income taxes	107,475	88,169	110,203	159,483	192,728
Provision for income taxes[(a)]	8,322				
Net income	$ 99,153	$ 88,169	$ 110,203	$ 159,483	$ 192,728
Basic net income per limited partner unit	$ 1.84	$ 1.66	$ 1.72	$ 2.04	$ 2.24
Diluted net income per limited partner unit	$ 1.84	$ 1.66	$ 1.72	$ 2.03	$ 2.24
Balance Sheet Data:					
Working capital (deficit)[(b)]	$ 47,328	$ 77,438	$ 71,737	$ (206)	$ (341,371)
Total assets	1,120,359	1,194,624	1,817,832	1,876,518	1,952,649
Long-term debt[(b)]	570,000	569,100	789,568	782,639	518,609
Partners capital	451,757	498,149	789,109	807,990	806,482
Cash Distribution Data:					
Cash distributions declared per unit[(c)]	$ 1.36	$ 1.59	$ 1.76	$ 2.06	$ 2.34
Cash distributions paid per unit[(c)]	$ 1.29	$ 1.53	$ 1.72	$ 1.97	$ 2.29

	Year Ended December 31,				
	2002	2003	2004	2005	2006
	(in thousands, except operating statistics)				
Other Data:					
Operating margin:					
Petroleum products pipeline system	$ 163,233	$ 162,494	$ 192,841	$ 247,245	$ 279,596
Petroleum products terminals	43,844	46,909	58,522	69,414	91,297
Ammonia pipeline system	8,272	8,094	7,328	7,685	2,541
Allocated partnership depreciation costs[d]		873	3,029	3,406	3,583
Operating margin	$ 215,349	$ 218,370	$ 261,720	$ 327,750	$ 377,017
EBITDA:					
Net income	$ 99,153	$ 88,169	$ 110,203	$ 159,483	$ 192,728
Provision for income taxes[a]	8,322				
Debt prepayment premiums			12,666		
Write-off of unamortized debt placement fees			5,002		
Debt placement fee amortization	9,950	2,830	3,056	2,871	2,681
Interest expense, net	21,758	34,536	35,435	48,258	53,010
Depreciation and amortization	35,096	36,081	41,845	56,307	60,852
EBITDA	$ 174,279	$ 161,616	$ 208,207	$ 266,919	$ 309,271
Operating statistics:					
Petroleum products pipeline system:					
Transportation revenue per barrel shipped	$ 0.949	$ 0.964	$ 0.997	$ 1.026	$ 1.060
Transportation barrels shipped (millions)	234.6	237.6	255.0	297.7	308.7
Petroleum products terminals:					
Marine terminal average storage utilized (million barrels)[e]	16.2	15.2	16.4	18.6	19.1
Inland terminal throughput (million barrels)	57.3	61.2	101.2	111.1	121.9
Ammonia pipeline system:					
Volume shipped (thousand tons)	712	614	765	713	726

(a) Prior to our acquisition of Magellan Pipeline on April 11, 2002, Magellan Pipeline was subject to income taxes. Because we are a partnership, Magellan Pipeline was no longer subject to income taxes following our acquisition of it.

(b) The Magellan Pipeline notes (see Note 13 Debt in the accompanying consolidated financial statements) mature on 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. We intend to refinance this debt before its maturity in October 2007.

(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. Prior to 2003, all property, plant and equipment was recorded 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. Consequently, segment operating margins were reduced by these costs.

(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 (0.6 million barrels) and the weighted average storage capacity utilized for the full year at our other marine terminals (15.8 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 (16.8 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, 2006, our three operating segments include:

- petroleum products pipeline system, which is primarily comprised of our 8,500-mile petroleum products pipeline system, including 45 terminals;
- petroleum products terminals, which principally includes our seven marine terminal facilities and 29 inland terminals; and
- ammonia pipeline system, representing our 1,100-mile ammonia pipeline and six associated terminals.

The following discussion provides an analysis of the results for each of our operating segments, an overview of our liquidity and capital resources and other items related to our company. 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, 2006.

Recent Developments

Distribution. On January 25, 2007 the board of directors of our general partner declared a quarterly cash distribution of $0.6025 per unit for the period of October 1 through December 31, 2006. We declared distributions equal to $2.34 per unit related to 2006 compared to $2.06 per unit related to 2005, an increase of 14%. The $0.6025 per unit distribution was paid on February 14, 2007 to unitholders of record on February 5, 2007.

Board of director changes. Our general partner is partially owned by Carlyle/Riverstone Global Energy and Power Fund II, L.P. (CRF). CRF is part of an investment group that has agreed to purchase Kinder Morgan, Inc. To alleviate competitive concerns the Federal Trade Commission ("FTC") raised regarding the transaction, CRF agreed with the FTC to remove their representatives from our general partner s board of directors. This agreement was announced on January 25, 2007. One of CRF s representatives, Jim H. Derryberry, had previously resigned from our general partner s board of directors effective October 24, 2006 and its other representative, N. John Lancaster, Jr., resigned as a director effective January 30, 2007. On January 29, 2007, our general partner s board of directors elected Thomas T. Macejko, Jr., a Vice President of Madison Dearborn Partners, LLC to fill one of the vacancies created by these resignations. The other vacancy has not yet been filled.

Overview

Our petroleum products pipeline system and petroleum products terminals generate substantially all of our cash flows. 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. 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. The pipeline generates approximately 80% 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.

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 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. Effective February 2003, we entered into an agreement with a third-party pipeline company to operate our ammonia pipeline system. Operating costs and expenses charged to us are principally fixed costs related to maintenance and field personnel. Other costs, including power, fluctuate with volumes transported on the pipeline.

Acquisition History

We have significantly increased our operations over the past three years, including the following acquisitions:

- in November and December 2005, the acquisition of two terminals on our petroleum products pipeline system, located in Wichita, Kansas and Aledo, Texas;

- in September 2005, the acquisition of a marine terminal near Wilmington, Delaware;

- in October 2004, the acquisition of a 2,000-mile petroleum products pipeline system;
- in March 2004, the acquisition of a 50% ownership interest in a crude oil pipeline company; and
- in January 2004, the acquisition of six inland terminals and the remaining 21% ownership interest in eight terminals.

Organic Growth Projects

We also have increased our operations through organic growth projects that expand or upgrade our existing facilities. During 2006, we spent $135.6 million on organic growth projects, which was more than double our 2005 spending on these projects. Further, we expect to spend approximately $115.0 million in 2007 on projects that are currently underway or in advanced stages of development and $20.0 million in 2008 to complete these projects.

Our current organic growth is driven by a number of economic and business factors, including:

- growing demand for refined petroleum products in the markets currently served by our petroleum products pipeline system and petroleum products terminals;
- new government regulations, including the reduction of sulfur in diesel fuel and increasing usage of 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
- increased petroleum storage demand driven by increased imports and our customers desire for security of supply, providing us opportunities to build additional storage tanks along our petroleum products pipeline system and at our petroleum products terminals.

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

	Year Ended		Variance	
	December 31,		Favorable (Unfavorable)	
	2005	**2006**	**$ Change**	**% Change**
Financial Highlights ($ in millions, except operating statistics)				
Revenues:				
Transportation and terminals revenues:				
Petroleum products pipeline system	$ 381.9	$ 413.3	$ 31.4	8
Petroleum products terminals	105.6	131.9	26.3	25
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	185.4	187.7	(2.3)	(1)
Petroleum products terminals	42.3	49.3	(7.0)	(17)
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 expense	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	$ 1.026	$ 1.060		
Transportation barrels shipped (million barrels)	297.7	308.7		
Petroleum products terminals:				
Marine terminal average storage utilized (million barrels)[a]	18.6	19.1		
Inland terminal throughput (million barrels)	111.1	121.9		
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 (16.8 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 $31.4 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 $26.3 million due in part to additional revenue from our Wilmington, Delaware marine terminal, which we acquired in September 2005, and revenue from two marine terminal variable-rate storage agreements in 2006. We have negotiated a similar variable-rate storage agreement in 2007, pursuant to which we will receive a discounted storage rate fee plus a share of any net trading profits above a specified level during 2007, but we will not share in any net trading losses. We expect revenue from the 2007 agreement to be less than the $9.4 million realized in 2006. Revenues also increased at our inland terminals due to higher additive fees and record throughput volumes and at our marine terminals primarily due to higher storage rates and additive fees and expansion projects completed over the past year; and

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

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

- an increase in petroleum products pipeline system expenses of $2.3 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 principally reflecting higher commodity prices and sales of accumulated system overages, which reduce operating expenses;

- an increase in petroleum products terminals expenses of $7.0 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. We expect the amount of system integrity spending to continue to increase in 2007 on our ammonia system due to the timing of 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 $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. As we have previously disclosed, 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 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 expense increased by $4.6 million related to asset acquisitions and capital improvements over the past year.

Affiliate G&A expenses increased by $6.0 million. We recognized $3.0 million of non-cash expense associated with certain distribution payments made over the past three years by our affiliate, MGG Midstream

Holdings, L.P., to an executive officer of our general partner who left the company during the fourth quarter of 2006. 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 the current period and increases in the number of units management estimates will vest under our equity-based incentive compensation 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 Midstream Holdings, L.P. s distribution payments to our general partner s former executive officer and equity-based incentive compensation expense, the amount of cash we spend for G&A costs is determined by an agreement we have with Magellan Midstream Holdings, L.P. (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, excluding equity-based incentive compensation expense. The amount of G&A reimbursed to us for the years ended 2006 and 2005 was $1.7 million and $3.3 million, respectively. Based on our agreement with MGG, the amount of G&A costs we pay increases by 7% annually and by incremental G&A expenses related to completed acquisitions. Based on our current asset portfolio, we expect to pay G&A costs, net of reimbursements, of approximately $57.0 million during 2007.

Interest expense, net of capitalized interest, was $55.1 million for the year ended December 31, 2006 compared to $52.6 million for the year ended December 31, 2005, an increase of $2.5 million, or 5%. The weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, increased to 7.0% for the 2006 period from 6.6% for the 2005 period primarily due to rising interest rates. 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 amount of capitalized interest in the current period associated with our capital spending program also increased, further reducing the net interest expense in 2006.

Interest income was $2.1 million during 2006 compared to $4.3 million in 2005, a decline of $2.2 million, primarily as a result of a lower cash balance. During 2006 we used available cash to fund our increased expansion capital projects, resulting in average lower cash balances for financial investment.

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

Year Ended December 31, 2004 Compared to Year Ended December 31, 2005

	Year Ended		Variance	
	December 31,		Favorable (Unfavorable)	
	2004	2005	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Revenues:				
Transportation and terminals revenues:				
Petroleum products pipeline system	$ 315.0	$ 381.9	$ 66.9	21
Petroleum products terminals	91.3	105.6	14.3	16
Ammonia pipeline system	13.9	15.8	1.9	14
Intersegment eliminations	(1.1)	(3.1)	(2.0)	(182)
Total transportation and terminals revenues	419.1	500.2	81.1	19
Product sales	275.8	636.2	360.4	131
Affiliate management fees	0.5	0.7	0.2	40
Total revenues	695.4	1,137.1	441.7	64
Operating expenses:				
Petroleum products pipeline system	140.2	185.4	(45.2)	(32)
Petroleum products terminals	37.1	42.3	(5.2)	(14)
Ammonia pipeline system	6.6	8.2	(1.6)	(24)
Intersegment eliminations	(4.2)	(6.1)	1.9	45
Total operating expenses	179.7	229.8	(50.1)	(28)
Product purchases	255.6	582.7	(327.1)	(128)
Equity earnings	(1.6)	(3.1)	1.5	94
Operating margin	261.7	327.7	66.0	25
Depreciation and amortization expense	41.8	56.3	(14.5)	(35)
Affiliate G&A expense	54.5	61.1	(6.6)	(12)
Operating profit	$ 165.4	$ 210.3	$ 44.9	27
Operating Statistics				
Petroleum products pipeline system:				
Transportation revenue per barrel shipped	$ 0.997	$ 1.026		
Transportation barrels shipped (million barrels)	255.0	297.7		
Petroleum products terminals:				
Marine terminal average storage utilized (million barrels)[(a)]	16.4	18.6		
Inland terminal throughput (million barrels)	101.2	111.1		
Ammonia pipeline system:				
Volume shipped (thousand tons)	765	713		

(a) For the year ended December 31, 2004, represents the average storage capacity utilized for the three months we owned our East Houston, Texas facility (0.6 million barrels) and the average storage capacity utilized for the full year at our other marine terminals (15.8 million barrels). 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 (16.8 million barrels).

Transportation and terminals revenues increased by $81.1 million resulting from higher revenues for each of our business segments as shown below:

an increase in petroleum products pipeline system revenues of $66.9 million primarily attributable to revenues from our October 2004 pipeline system acquisition. In addition, our existing pipeline system experienced higher revenues because of increased diesel fuel shipments. Further, we earned more ancillary revenues related to services such as additives, ethanol blending, terminal services and management fee income;

- an increase in petroleum products terminals revenues of $14.3 million. The 2005 period benefited from our East Houston marine terminal, which was acquired as part of our pipeline system acquisition in October 2004, and our Wilmington marine facility, which we acquired in September 2005. Revenues at our other marine terminals increased as well due to higher storage capacities, utilization and rates. Increased throughput and higher additive fees at our inland terminals further benefited the 2005 period; and

- an increase in ammonia pipeline system revenues of $1.9 million. Higher tariffs associated with new transportation agreements, which became effective July 1, 2005, more than offset reduced volumes. The lower volumes primarily reflect customers continued maintenance of tight inventory levels due to increased production costs as a result of higher natural gas prices in 2005.

Operating expenses increased by $50.1 million. Each of our business segments incurred additional expenses as follows:

- an increase in petroleum products pipeline system expenses of $45.2 million, primarily attributable to operating costs associated with the pipeline system we acquired in October 2004. Increased expenses related to higher environmental accruals associated with historical incidents, power costs and system integrity spending for tank maintenance and pipeline testing also impacted the 2005 period;

- an increase in petroleum products terminals expenses of $5.2 million. Expenses increased due to operating costs associated with the acquisitions of our East Houston and Wilmington marine facilities. In addition, 2005 expenses were higher because of environmental accruals associated with historical incidents, asset retirements and property taxes; and

- an increase in ammonia pipeline system expenses of $1.6 million, primarily attributable to increased system integrity costs and higher property taxes due to an adjustment that positively impacted the 2004 period.

Revenues from product sales were $636.2 million for the year ended December 31, 2005, while product purchases were $582.7 million, resulting in gross margin from these transactions of $53.5 million. The gross margin resulting from product sales and purchases for the 2005 period increased $33.3 million compared to gross margin for the 2004 period of $20.2 million, resulting from product sales for the year ended December 31, 2004 of $275.8 million and product purchases of $255.6 million. The gross margin increase in 2005 primarily resulted from the impact of very high and increasing gasoline prices on our petroleum products blending and fractionation operations and the third-party supply agreement we assumed as part of the pipeline assets we acquired in October 2004.

Equity earnings increased by $1.5 million due primarily to increased shipments on our 50%-owned crude oil pipeline company that we acquired in March 2004 and a full year ownership in 2005 compared to 10 months in 2004.

Operating margin increased $66.0 million, primarily due to incremental operating results associated with acquisitions, higher gross margin from product sales and improved utilization of our other assets.

Depreciation and amortization expense increased by $14.5 million related to asset acquisitions and capital improvements.

Affiliate G&A expenses increased by $6.6 million. This increase was primarily attributable to additional G&A personnel and costs resulting from our October 2004 pipeline system acquisition. Higher equity-based incentive compensation expense during the 2005 period was partially offset by transition costs associated with our separation from the former owner of our general partner during the 2004 period. Excluding equity-based incentive compensation expense, our actual cash outlay for G&A costs, as determined by our agreement with MGG, was $49.9 million for 2005 and $42.1 million for 2004.

Interest expense, net of capitalized interest, was $52.6 million for the year ended December 31, 2005 compared to $37.9 million for the year ended December 31, 2004, an increase of $14.7 million, or 39%. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased to $799.4 million during 2005 from $622.6 million during 2004 primarily due to the financing associated with our October 2004 pipeline system acquisition. Further, the weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, increased to 6.6% for the 2005 period from 6.1% for the 2004 period primarily due to rising interest rates.

Interest income increased from $2.5 million for the 2004 period to $4.3 million for the 2005 period, primarily because of the increase in cash available for short-term investments during 2005.

While we had no refinancing costs in 2005, net refinancing costs were $16.7 million during 2004. These costs included a $12.7 million debt prepayment premium related to the early extinguishment of a portion of our Magellan Pipeline Company, L.P. (Magellan Pipeline) notes in May 2004 and a $5.0 million write-off for unamortized debt placement fees associated with the retired debt. Partially offsetting these charges was a $1.0 million gain on an interest rate hedge related to the refinancing.

Net income was $159.5 million for the year ended December 31, 2005 compared to $110.2 million for the year ended December 31, 2004, an increase of $49.3 million, or 45%.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $304.7 million for the year ended December 31, 2006, $224.8 million for 2005 and $236.5 million for 2004.

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

> a $33.2 million increase in net income in 2006;

> a $21.4 million increase in cash from operations relative to net changes in inventories. Although inventories increased $13.4 million in 2006 over 2005, that increase was $21.4 million less than the $34.8 million increase in inventories during 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; and

> a $21.9 million increase in cash relative to net changes in accounts payable and accrued product purchases. The increase is primarily due to the timing of invoices received from our vendors and suppliers.

The $11.7 million decrease from 2004 to 2005 was primarily attributable to:

> an increase in accounts receivable and inventory of $13.3 million and $34.8 million, respectively, primarily resulting from the third-party supply agreement we assumed in connection with our October 2004 pipeline system acquisition;

> a decrease in accrued product shortages of $7.5 million in 2005 compared to an increase in 2004 of $7.5 million; and

> a decrease in cash collateral associated with our third-party supply agreement of $1.5 million in 2005 compared to an increase in cash collateral in 2004 of $14.0 million.

These decreases were partially offset by:

> a $49.3 million increase in net income in 2005; and

> an increase in accrued product purchases of $17.5 million primarily due to the increase in inventory described above.

Net cash used by investing activities for the years ended December 31, 2006, 2005 and 2004 was $148.3 million, $75.7 million and $712.3 million, respectively. During 2006, we spent $168.5 million for capital expenditures, of which $32.9 million was for maintenance capital and $135.6 million was for expansion capital. Significant expenditures of expansion capital during 2006 included new storage tanks, including new tanks at our Galena Park, Texas terminal, new pipeline construction and pipeline connections, equipment to comply with ultra low sulfur diesel fuel mandates, additions to delivery racks and ethanol blending equipment. 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. These cash expenditures were partially offset by our sales of marketable securities which, net of purchases, generated $87.8 million of cash. During 2004, our net investments in marketable securities used $87.8 million of cash. In addition, we acquired the following assets during 2004: (i) ownership in 14 petroleum products terminals located in the southeastern United States for $25.4 million; (ii) a 50% ownership in a crude oil pipeline company for $25.0 million; and (iii) petroleum products pipeline system assets for $488.9 million plus $3.3 million of incurred transaction costs and $30.1 million for inventory.

Net cash provided by (used in) financing activities for the years ended December 31, 2006, 2005 and 2004 was $(186.5) million, $(142.5) million and $394.3 million, respectively. Cash was used during 2006 and 2005 primarily to pay cash distributions to our unitholders. Cash provided during 2004 principally included the debt and equity financings that were completed in conjunction with our pipeline system acquisition in October 2004, partially offset by the repayment of debt in connection with our May 2004 refinancing and cash distributions paid. Capital contributions from our general partner were $28.7 million, $20.1 million and $14.8 million during 2006, 2005 and 2004, respectively, which was primarily due to payments we received under the May 2004 environmental indemnity settlement and amounts received under the G&A cost cap agreement and in 2006, compensation costs paid by MGG Midstream Holdings, L.P.

During 2006, we paid $208.0 million in cash distributions to our unitholders. The quarterly distribution amount associated with the fourth quarter of 2006 was $0.6025 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 185,673 common units representing limited partner interests in us (limited partner units) on January 26, 2007 (see Note 24 Subsequent Events in the accompanying consolidated financial statements), total cash distributions of $225.2 million would be paid to our unitholders in 2007, of which $64.8 million, or 29%, 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, referred 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 2006, our maintenance capital spending was $26.2 million, excluding $6.5 million of spending that would have been covered by indemnifications settled in May 2004 and $0.2 million for which we expect to be reimbursed by insurance. Including the $20.0 million payment we received on July 1, 2006, we have received $82.5 million to date under an indemnification settlement agreement with a former affiliate. Please see Environmental below for additional discussion of this indemnification settlement.

For 2007, we expect to incur maintenance capital expenditures for our existing businesses of approximately $34.0 million, excluding $8.0 million of maintenance capital that would have been covered by the indemnification discussed above and $2.0 million we expect to receive from insurance reimbursements.

In addition to maintenance capital expenditures, we also incur expansion capital expenditures at our existing facilities. During 2006, we spent cash of approximately $135.6 million for organic growth projects. Based on projects currently underway or in advanced stages of development, we currently plan to spend $115.0 million on organic growth capital in 2007, excluding future acquisitions, and approximately $20.0 million in 2008 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.

As of December 31, 2006, total debt reported on our consolidated balance sheet was $789.4 million, as described below. The difference between this amount and the $793.1 million face value of our outstanding debt is due to adjustments associated with the fair value hedges we have in place for a portion of our outstanding debt and unamortized discounts on debt issuances.

Magellan Pipeline Notes. Magellan Pipeline entered into a private placement debt agreement with a group of financial institutions for $480.0 million of fixed rate senior notes, comprised of $178.0 million of Series A notes and $302.0 million of Series B notes. We repaid the Series A notes in 2004 and we made scheduled payments on the Series B notes of $15.1 million on October 7, 2005 and $14.3 million on October 7, 2006. The face value of the notes outstanding on December 31, 2006 was $272.6 million. The maturity date of the notes is October 7, 2007; therefore, we have classified these notes as current liabilities on our December 31, 2006 consolidated balance sheet. We anticipate refinancing this debt prior to its maturity in October 2007. The weighted-average interest rate for the notes, including the impact of the swap of $250.0 million of the notes from fixed-rate to floating-rate, was approximately 8.6% at December 31, 2006. We guarantee payment of interest and principal by Magellan Pipeline.

The note purchase agreement under which these notes were issued, as amended in May 2004, requires Magellan Pipeline to maintain specified ratios of: (i) consolidated debt to EBITDA of no greater than 3.50 to 1.00, and (ii) consolidated EBITDA to interest expense of at least 3.25 to 1.00. It also requires us to maintain specified ratios of: (i) consolidated debt to EBITDA of no greater than 4.50 to 1.00, and (ii) consolidated EBITDA to interest expense of at least 2.50 to 1.00. In addition, the note purchase agreement contains additional covenants that limit Magellan Pipeline s ability to, among other things, incur additional indebtedness, encumber its assets, make debt or equity investments, make loans or advances, engage in certain transactions with affiliates, merge, consolidate, liquidate or dissolve, sell or lease a material portion of its assets, engage in certain sale and leaseback transactions and change the nature of its business. We are in compliance with these covenants.

Revolving Credit Facility. Our current revolving credit facility has a borrowing capacity of $400.0 million. The facility s maturity date is May 2011 and the interest rate on borrowings under the facility is 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 credit facility are unsecured. As of December 31, 2006, $20.5 million was outstanding under this facility, and $1.1 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, 2006, the weighted-average interest rate on borrowings outstanding under this facility was 5.8%.

The revolving credit facility requires us to maintain specified ratios of consolidated debt to EBITDA of no greater than 4.75 to 1.0. In addition, the facility contains other covenants limiting our ability to incur additional indebtedness or modify our other debt instruments, encumber our assets, make debt or equity investments, make loans or advances, engage in certain transactions with affiliates, engage in sale and leaseback transactions, merge, consolidate, liquidate, dissolve or sell or lease all or substantially all of our assets or change the nature of our business. We are in compliance with these covenants.

6.45% Senior Notes due 2014. On May 25, 2004, we sold $250.0 million of 6.45% senior notes due 2014 in an underwritten public offering at 99.8% of par. We received proceeds after underwriters fees and expenses of approximately $246.9 million. Including the impact of pre-issuance hedges associated with these notes, the effective interest rate on these notes at December 31, 2006 was 6.3%.

5.65% Senior Notes due 2016. On October 15, 2004, we sold $250.0 million of 5.65% senior 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, and we received proceeds after underwriters fees and expenses of approximately $247.6 million. Including the impact of pre-issuance hedges associated with these notes and the swap of $100.0 million of the notes from fixed-rate to floating-rate, the weighted-average interest rate on the notes at December 31, 2006 was 6.0%.

The indentures under which both the 6.45% and 5.65% notes were issued do not limit our ability to incur additional unsecured debt. The indentures contain covenants limiting, among other things, our ability to incur indebtedness secured by certain liens, engage in certain sale-leaseback transactions, and consolidate, merge or dispose of all or substantially all of our assets. We are in compliance with these covenants.

Interest Rate Derivatives. We utilize interest rate derivatives to manage interest rate risk. We were engaged in the following derivative transactions as of December 31, 2006:

In September and November 2006, we entered into a total of $250.0 million of forward starting interest rate swap agreements to hedge against variability of future interest payments on a portion of the debt we anticipate issuing no later than October 2007. Proceeds of the anticipated debt issuance will be used to refinance the Magellan Pipeline notes, which mature in October 2007. The interest rate swap agreements have a 30-year term, which matches the expected tenor of the anticipated debt. The effective date of the agreements is October 9, 2007, at which time the agreements require a mandatory cash settlement. The fixed rate provided in the agreements is 5.3%; assuming no changes in swap spreads between the date we entered these agreements and the date we settle these agreements, these agreements will effectively fix the rate on the treasury component of our anticipated debt issuance at approximately 4.8%;

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% senior 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% senior notes; and

In May 2004, we entered into $250.0 million of interest rate swap agreements to hedge against changes in the fair value of a portion of the Magellan Pipeline notes. These agreements effectively change the interest rate on $250.0 million of the senior notes from a fixed rate of 7.7% to a floating rate of six-month LIBOR plus 3.4%, with LIBOR set in arrears. These swap agreements expire on October 7, 2007, the maturity date of the Magellan Pipeline notes.

Credit Ratings. Our current corporate credit ratings are BBB by Standard and Poor s and Baa3 by Moody s Investor Services.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2006 (in millions):

	Total	< 1 year	1-3 years	3-5 years	> 5 years
Long-term and current debt obligations[1]	$ 793.1	$ 272.6	$	$ 20.5	$ 500.0
Interest obligations	276.1	47.5	62.2	60.5	105.9
Operating lease obligations	18.8	3.0	3.5	2.9	9.4
Pension and postretirement medical obligations	29.4	4.7	4.9	5.5	14.3
Purchase commitments:					
Affiliate operating and G&A[2]					
Petroleum product purchases[3]	4.4	2.5	1.7	0.1	0.1
Utility purchase commitments	4.0	2.8	1.0	0.2	
Derivative financial instruments[4]					
Equity-based incentive awards[5]	20.7	11.0	9.7		
Environmental remediation[6]	24.6	8.2	7.7	5.0	3.7
Capital project purchase obligations	43.3	43.3			
Maintenance and facility security purchase obligations	1.7	1.5	0.2		
Other purchase obligations	1.4	0.8	0.6		
Long-term deposit	13.5				13.5
Total	$ 1,231.0	$ 397.9	$ 91.5	$ 94.7	$ 646.9

(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, 2006 ($20.5 million) will not be repaid until the maturity date of the facility in October 2011. The notes mature in October 2007 and their $270.8 million carrying value at December 31, 2006 was classified as a current liability on our consolidated balance sheet. We intend to refinance this debt with 30-year notes prior to its October 2007 maturity date.

(2) 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 2006 was $136.1 million.

(3) 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 of that commitment will be.

(4) On December 31, 2006, we had outstanding interest rate swap agreements to hedge against the fair value of $350.0 million of our long-term debt. Further, on December 31, 2006, we had outstanding $250.0 million of forward starting interest rate swap agreements to hedge against the variability of future interest payments on a portion of the debt we anticipate issuing no later than October 2007. Because future cash outflows under these derivative agreements, if any, are uncertain, they have been excluded from this table.

(5) Represents amounts we have accrued for equity-based incentive compensation through December 31, 2006 based on when those existing liabilities will be settled. We expect the amounts that will ultimately vest to our employees will exceed these amounts primarily due to anticipated compensation liabilities that will be recognized over the remainder of the vesting periods and changes in our unit prices between December 31, 2006 and the date the unit awards actually vest.

(6) On December 31, 2005, we entered into a 10-year agreement to reach contractual endpoint (as defined in the agreement) for 26 remediation sites. This contract obligates us to pay the remediation costs incurred by the contract counterparty associated with these 26 sites up to a maximum of $14.0 million. The amounts in the table above include the remaining amounts to be paid under this agreement ($12.4 million) and the estimated timing of these payments. 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. We incurred $4.3 million of costs associated with this agreement during 2006. The amounts in the table above include the remaining amounts to be paid under this agreement ($11.9 million) and the contractually-determined timing of those payments.

Environmental

Various governmental authorities in the jurisdictions in which we conduct our operations subject us to environmental laws and regulations. We have accrued liabilities for estimated site restoration costs to be incurred in the future at our facilities and properties, including liabilities for environmental remediation obligations at various sites where we have been identified as a possible responsible party. Under our accounting policies, we record liabilities when site restoration and environmental remediation obligations are either known or considered 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.

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. Including the $20.0 million payment we received on July 1, 2006, we have received $82.5 million pursuant to this agreement and expect to receive the remaining balance of $35.0 million on July 1, 2007. As of December 31, 2006, known liabilities that would have been covered by these indemnifications were $45.7 million. In addition, we have spent $31.7 million through December 31, 2006 that would have been covered by these indemnifications, including $13.4 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.

During the third quarter of 2006, we entered into an agreement with a contractor to mitigate against the risk of increases in certain of our existing environmental liabilities. The agreement requires that the contractor assume responsibility for the environmental remediation of certain sites and purchase cost cap insurance from an insurance company. We are an additional named insured under that policy and were required to pay the related insurance premium. In connection with this agreement, we increased the related environmental liabilities by $2.9 million, to equal the discounted value of the cash payments to be made to the contractor pursuant to the agreement, and recorded $2.2 million of expense to reflect risk and insurance premiums paid for a total charge of $5.1 million in 2006.

When MGG purchased our general partner interest in June 2003, MGG assumed obligations to indemnify us for $21.9 million of known environmental liabilities. As of December 31, 2006, we have incurred the entire $21.9 million of costs associated with this obligation and have been reimbursed by MGG. Therefore, we no longer have a receivable balance with MGG related to these environmental indemnities.

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 Magellan Pipeline, which 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 assumes 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 amounts we have accrued for this matter were included as part of the environmental indemnification settlement we reached with our former affiliate (see Note 18 Commitments and Contingencies in the accompanying consolidated financial statements). Due to the uncertainties described above, it is reasonably possible that the amounts we have recorded for this environmental liability could change in the near term. Management is in ongoing discussions with the EPA; however, we are unable to determine with any accuracy what our ultimate liability could be for this matter. Adjustments from amounts we currently have recorded to the final settlement amounts reached with the EPA could be material to our results of operations or cash flows.

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 was liable for penalties pursuant to Section 103 of the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) for failing to timely report the releases and that the statutory maximum for those penalties could be as high as $4.2 million. We are evaluating whether or not we have an indemnity obligation to the third party operator for all or a portion of the CERCLA penalties. Additionally, 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 and that it may seek injunctive relief if the parties cannot agree on any necessary corrective actions. We are currently in discussions with the EPA and DOJ regarding these two releases; however, we do not believe that the ultimate resolution of this matter will have a material impact on our results of operations, financial position or cash flows.

Polychlorinated Biphenyls (PCB) Impacts. We have identified PCB impacts at one of our petroleum products terminals that we are in the process of delineating. It is possible that in the near term after our delineation 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.

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 FERC reviews this approved methodology on a periodic basis. During March 2006, the FERC approved the methodology of producer price index for finished goods (PPI-FG) plus 1.3% for the annual adjustment related to the next five year period, commencing July 1, 2006. Based on an actual 2005 annual change in PPI-FG of approximately 4.8%, the 2006 mid-year adjustment resulted in an allowed increase on indexed tariffs of approximately 6.1%. We increased virtually all of our published tariffs by approximately 6.1% effective July 1, 2006. Preliminary data estimates PPI-FG for 2006 to be approximately 2.9%. Once PPI-FG is finalized, we would expect to increase the majority of our tariffs by the resulting PPI-FG plus 1.3% on July 1, 2007.

Galena Park marine terminal expansion. During late 2005 and early 2006, we executed a series of long-term terminalling agreements with several customers pursuant to which we will construct 30 new storage tanks at our Galena Park, Texas marine terminal. Construction is complete for 10 of the tanks which will be operational for all of 2007 and we expect the remaining 20 new tanks to be placed into service at intervals during the remainder of 2007 and in 2008. We believe these new agreements will significantly contribute to our results of operations and cash flows once construction is complete and all 30 new tanks have been placed into service.

***Unrecognized product gains*.** Our operations generate product overages and shortages. When we experience net product shortages, we recognize expense for those losses in the period in which they occur. When we experience product overages, we have product on hand for which we have no cost basis. Therefore, these 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 operations had a market value of approximately $8.7 million as of December 31, 2006. 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.

Postretirement benefit obligations. Assuming market conditions remain constant, we expect to contribute $5.7 million, $3.7 million and $5.7 million in 2007, 2008 and 2009, respectively to fund our postretirement pension obligations, which primarily include pension benefits for employees supporting our operations. In addition, we will fund retiree medical obligations as claims are made.

***State tax issues*.** Texas legislators recently passed a law that, without amendment, will impose a partnership-level tax beginning in 2007 based on the financial results of our assets apportioned to the state of Texas. While we currently expect our tax obligation to be less than $3.0 million per year, this tax will impact the amount of cash available for distributions to our unitholders. If other states create a similar tax, the impact could be material to our results of operations or cash flows.

Contract expiration. In connection with our October 2004 acquisition of a petroleum products pipeline system, we entered into three-year terminalling and transportation agreements with the seller for average minimum revenue commitments of approximately $27.0 million per year through September 30, 2007. We currently expect to retain most of this revenue. However, if we are unsuccessful in retaining this business, it could have a significant impact on our revenues, results of operations and cash flows after the current contracts expire.

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 to be 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 and (4) changes in federal, state and local environmental regulations could significantly increase the amount of the liability.

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.

Each quarter, 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, 2004 were as follows (in millions):

Balance	**2005**		**Balance**	**2006**		**Balance**
12-31-04	**Accruals**	**Expenditures**	**12-31-05**	**Accruals**	**Expenditures**	**12-31-06**
$60.8	$12.7	$(15.3)	$58.2	$16.4	$(16.8)	$57.8

In May 2004, we entered into an agreement with a former affiliate under which our former affiliate agreed to pay us $117.5 million to release it from its environmental and certain other indemnification obligations to us. From the effective date of our environmental indemnification settlement with our former affiliate, all accrual adjustments associated with amounts that would have been previously indemnified are no longer reimbursed and therefore impact our net income.

During 2005, we increased our environmental liability accruals by $12.7 million, of which $3.2 million related to pipeline product releases, $0.2 million related to acquisitions and the remainder was primarily attributable to our annual site assessment process. Our 2005 accruals included $0.7 million of amounts we recorded as accounts receivable from our insurance carriers.

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.

Our environmental liabilities at December 31, 2006 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 15% and assuming that none of this increase was covered by indemnifications or insurance, our expenses would increase by $8.7 million. Because we pay no income taxes, operating profit and net income would decrease by the same amount, which represents a decrease of 4% of our operating profit and 5% of our net income for 2006. Assuming our current distribution levels 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 and assets recorded in transactions designated as the acquisition of a business. Impaired assets are recorded at fair value on the last impairment evaluation date for which an adjustment was required. Assets recorded in transactions designated as the acquisition of a business are recorded at the fair value of the asset acquired. 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 incurred evenly over the life of the asset. At December 31, 2005 and 2006, the gross book value of our property, plant and equipment was $2.1 billion and $2.3 billion, respectively, and we recorded depreciation expense of $54.9 million and $59.3 million during 2005 and 2006, respectively.

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 2006 would increase by $9.3 million. Because we pay no income taxes, operating profit and net income would decrease by the same amount, which represents a decrease of 4% of our operating profit and 5% of our net income for 2006. Assuming our current distribution levels for the entire year, this additional expense would reduce basic net income per limited partner unit by $0.09 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 October 2006, the Financial Accounting Standards Board (FASB) adopted Statement of Financial Accounting Standard (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 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 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. 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 are considering adopting this standard for 2007 but have not yet made a final decision. The adoption of this standard will 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 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.

In November 2005, the FASB issued FSP No. FAS 115-1 and FAS 124-1, The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments. This FSP addresses the determination as to when an investment is considered impaired, whether that impairment is other than temporary and the measurement of an impairment loss. This FSP also includes accounting considerations subsequent to the recognition of an other-than-temporary impairment and requires certain disclosures about unrealized losses that have not been recognized as other-than-temporary impairments. The guidance in this FSP amends FASB Statement No. 115, Accounting for Certain Investments in Debt and Equity Securities, FASB Statement No. 124, Accounting for Certain Investments Held by Not-for-Profit Organizations, and Accounting Principles Board (APB) Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock. The guidance in this FSP is to be applied to reporting periods beginning after December 15, 2005. We adopted this FSP on January 1, 2006, and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In October 2005, the FASB issued FSP No. 13-1, Accounting for Rental Costs Incurred During a Construction Period. This FSP requires entities who incur rental costs associated with operating leases to expense such costs as a continuing operating expense. This FSP is required to be implemented beginning January 1, 2006, with early adoption permitted. We adopted the FSP on January 1, 2006, and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In September 2005, the FASB issued Emerging Issue Task Force (EITF) issue No. 04-13, Accounting for Purchases and Sales of Inventory With the Same Counterparty. In EITF No. 04-13, the FASB reached a tentative conclusion that inventory purchases and sales transactions with the same counterparty that are entered into in contemplation of one another should be combined for purposes of applying APB No. 29, Accounting for Nonmonetary Transactions. The tentative conclusions reached by the FASB are required to be applied to transactions completed in reporting periods beginning after March 15, 2006. We adopted this EITF on March 16, 2006, and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In May 2005, the FASB published SFAS No. 154, Accounting Changes and Error Corrections. SFAS No. 154 requires retrospective application to prior periods financial statements of every voluntary change in accounting principle unless it is impracticable to do so. SFAS No. 154 also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. SFAS No. 154 requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle, such as a change in nondiscretionary profit-sharing payments resulting from an accounting change, should be recognized in the period of the accounting change. We adopted this SFAS No. 154 on January 1, 2006, and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In March 2005, the FASB issued Financial Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations (as amended). FIN 47 clarified that the term *conditional asset retirement obligation* as used in SFAS No. 143, Accounting for Asset Retirement Obligations, refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing or method of settlement. Thus, the timing or method of settlement may be conditional on a future event. Accordingly, 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 reasonably estimated. The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred generally upon acquisition, construction or development or through the normal operation of the asset. Uncertainty about the timing or method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. SFAS No. 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. This Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN No. 47 was required to be adopted no later than the end of fiscal years ending after December 15, 2005, with retrospective application for interim financial information permitted. We adopted FIN No. 47 in 2005, and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In December 2004, the FASB issued a revision to SFAS No. 123, Share-Based Payment, as amended, referred to as SFAS No. 123(R). This Statement and subsequent amendments establish accounting standards for transactions in which an entity exchanges its equity instruments for goods or services. This SFAS requires that all equity-based compensation awards to employees be recognized in the income statement based on their fair values, eliminating the alternative to use APB No. 25 s intrinsic value method. SFAS No. 123(R) was effective as of the beginning of the first interim period that began after December 31, 2005. SFAS No. 123(R) applies to all awards granted after the required effective date but was not to be applied to awards granted in periods before the required effective date except to the extent that awards from prior periods were modified, repurchased or cancelled after the required effective date. We adopted SFAS No. 123(R) on January 1, 2006, using the modified prospective application method. Under the modified prospective method, we were required to account for all of our equity-based incentive awards granted prior to January 1, 2006, using the fair value method as defined in SFAS No. 123 instead of our then-current methodology of using the intrinsic value method as defined in APB No. 25. Due to the structure of our awards, we recognized compensation expense under APB No. 25 in much the same manner as that required under SFAS No. 123. Consequently, for the awards granted prior to January 1, 2006, the initial adoption and application of SFAS No. 123(R) did not have a material impact on our results of operations, financial position or cash flows.

Related Party Transactions

In March 2004, we acquired a 50% ownership interest in a crude oil pipeline company and began operating the related pipeline, for which we received operating fees of $0.5 million during 2004 and $0.7 million during both 2005 and 2006, which we reported as affiliate management fee revenues. In 2004, we also received $0.3 million for fees to transition accounting, billing and other administrative functions to us. We recorded these fees as a reduction to operating expenses in our results of operations.

Transactions between us and our affiliates are accounted for as affiliate transactions. The following table summarizes affiliate costs and expenses that are reflected in our consolidated statements of income (in thousands):

	Year Ended December 31,		
	2004	**2005**	**2006**
MGG allocated operating expenses	$ 58,777	$ 65,360	$
MGG allocated G&A expenses	54,466	60,261	
MGG GP allocated operating expenses		1,551	73,611
MGG GP allocated G&A expenses		870	40,830
MGG Midstream Holdings, L.P. allocated G&A expenses			3,000

Under our services agreement with MGG, we reimbursed MGG for all payroll and benefit costs it incurred from January 1, 2004 through December 24, 2005. On December 24, 2005, the employees necessary to conduct our operations were transferred to Magellan Midstream Holdings GP, LLC (MGG GP), MGG s general partner, 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, 2005 and 2006 was $17.0 million and $18.7 million, respectively, and the long-term affiliate pension and benefits accruals associated with this agreement at December 31, 2005 and December 31, 2006 were $9.8 million and $29.3 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 contributions to MGG when MGG makes contributions to MGG GP s pension fund.

In June 2003, we and our general partner entered into an agreement with MGG 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 was $6.4 million, $3.3 million and $1.7 million in 2004, 2005 and 2006, respectively.

A former executive officer of our general partner had an investment in MGG Midstream Holdings, L.P., which is an affiliate of ours and our general partner. This former executive officer left the company during the fourth quarter of 2006 and at that time we were allocated $3.0 million of G&A compensation expense associated with certain distribution payments made by MGG Midstream Holdings, L.P. to this individual over the past three years.

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 18 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 the Carlyle/Riverstone Global Energy and Power Fund II, L.P. (CRF). As of December 31, 2006, one 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 had adopted a policy to address board of director conflicts of interests. In compliance with this policy, CRF had adopted procedures internally to assure that our proprietary and confidential information is protected from disclosure to competing companies in which CRF owns an interest. As part of these procedures, CRF had agreed that none of its representatives would serve on our general partner s board of directors and on the boards of directors of competing companies in which CRF owns an interest. Effective January 30, 2007, all of the representatives of CRF have resigned from the board of directors of our general partner. See Note 24 Subsequent Events in the accompanying consolidated financial statements for a discussion of this matter.

On January 25, 2005, CRF, through affiliates, acquired general and limited partner interests of SemGroup, L.P. (SemGroup). CRF s total combined general and limited partner interests in SemGroup are approximately 30%. One of the members of the seven-member board of directors of SemGroup s general partner is a representative of CRF, with three votes on that board. We are a party to a number of transactions with SemGroup and its affiliates. A summary of these transactions is provided in the following table (in millions):

	January 25, 2005 through December 31, 2005	Year Ended December 31, 2006
Product sales revenues	$ 144.8	$ 177.1
Product purchases	90.0	63.2
Terminalling and other services revenues	5.9	4.4
Storage tank lease revenue	2.8	3.4
Storage tank lease expense	1.0	1.0

In addition to the above, we provide common carrier transportation services to SemGroup. As of December 31, 2005 and 2006, we had recognized a receivable of $6.2 million and $4.0 million, respectively, from and a payable of $6.1 million and $18.8 million, respectively, to SemGroup and its affiliates. The receivable is included with the trade accounts receivable amounts and the payable is included with the accounts payable amounts on our 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. During 2006, we incurred construction costs of $6.1 million for these tanks and we estimate we will incur additional costs of approximately $1.0 million in 2007. The loss on sale of these tanks will be deferred and amortized over the 10-year life of the lease. We and SemGroup s affiliate have further agreed that in exchange for its lease to us of these tanks, we will provide 400,000 barrels of storage on our pipeline system. In addition, we and SemGroup s affiliate have entered into a separate storage tank maintenance agreement which specifies that we will, at our own cost, provide routine maintenance for the tanks over the initial 10-year term of the lease. The fair value of this maintenance agreement is estimated at $0.1 million, which was recorded as a deferred cost and will be recognized over the 10-year life of the lease. In return for these agreements, SemGroup agreed to a three-year throughput agreement on our pipeline.

CRF also has 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 Partners, L.P. We incurred no operating expenses with Buckeye or its subsidiaries during 2004 or 2006.

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. For the period May 1, 2005 through December 31, 2005, and the year ended December 31, 2006, our operating expenses included $1.7 million and $2.9 million, respectively, of principally power costs that we incurred with Public Service Company of Oklahoma, which is a subsidiary of American Electric Power Company, Inc. We had no amounts payable to or receivable from Public Service Company of Oklahoma or American Electric Power Company Inc. at either December 31, 2005 or December 31, 2006.

Because our distributions have exceeded target levels as specified in our partnership agreement, our general partner receives 50% of any incremental cash distributed per limited partner unit. As of December 31, 2006, our executive officers collectively owned approximately 5% of MGG Midstream Holdings, L.P., which owns 65% of MGG. Therefore, our executive officers indirectly benefit from distributions paid to our general partner. In 2004, 2005 and 2006, distributions paid to our general partner, based on its general partner interest and incentive distribution rights, totaled $16.7 million, $30.1 million and $56.3 million, respectively. In addition, during 2004 and 2005, MGG received distributions totaling $28.7 million and $5.0 million, respectively, 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 do not expect our ownership structure or operations to be 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. See Note 24 Subsequent Events in the accompanying consolidated financial statements for a discussion of changes to our general partner s ownership interest in us after December 31, 2006. 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.

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;
- 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 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 or the debt of our subsidiaries 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 under indemnification agreements;

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

As of December 31, 2006, we had $20.5 million outstanding on our variable rate revolving credit facility. We had no other variable rate debt outstanding; however, because of certain interest rate swap agreements discussed below, we are exposed to interest rate market risk on an additional $350.0 million of our debt; however, $250.0 million of these interest rate swaps expire in October 2007. Considering these interest rate swap agreements and the amount outstanding on our revolving credit facility as of December 31, 2006, our annual interest expense would change by $0.4 million if LIBOR were to change by 0.125%.

During May 2004, we entered into four separate interest rate swap agreements to hedge against changes in the fair value of a portion of the Magellan Pipeline notes. We have accounted for these interest rate hedges as fair value hedges. The notional amounts of the interest rate swap agreements total $250.0 million. Under the terms of the agreements, we receive 7.7% (the interest rate on the Magellan Pipeline notes) and pay LIBOR plus 3.4%. These hedges effectively convert $250.0 million of our fixed-rate debt to floating-rate debt. The interest rate swap agreements began on May 25, 2004 and expire on October 7, 2007. Payments settle in April and October of each year with LIBOR set in arrears. We recognized liabilities of $2.5 million and $1.8 million for the fair value of these agreements on December 31, 2005 and 2006, respectively.

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 non-current asset of $0.3 million at December 31, 2005, and deferred liabilities of $1.2 million at December 31, 2006, for the fair value of this agreement.

In September 2006 and November 2006, we entered into a total of $250.0 million of forward starting interest rate swap agreements to hedge against variability of future interest payments on a portion of the debt we anticipate issuing no later than October 2007. Proceeds of the anticipated debt issuance will be used to refinance the Magellan Pipeline notes, which mature in October 2007. The interest rate swap agreements have a 30-year term, which matches the expected tenor of the anticipated debt. The effective date of the agreements is October 9, 2007, at which time the agreements require a mandatory cash settlement. The fixed rate provided in the agreements is 5.3%; assuming no changes in swap spreads between the date we entered these agreements and the date we settle these agreements, these agreements will effectively fix the rate on the treasury component of our anticipated debt issuance at approximately 4.8%. The fair value of these agreements at December 31, 2006 was $0.2 million, which was recorded to other current assets and other comprehensive income. A 0.125% change in interest rates would result in an increase or decrease in the fair value of these agreements of approximately $4.5 million.

As of December 31, 2006, we had entered into futures contracts, qualifying as normal purchases, for the purchase of approximately 25,000 barrels of petroleum products. The notional value of these agreements on December 31, 2006 was approximately $1.7 million.

As of December 31, 2006, we had entered into futures contracts, qualifying as normal sales, for the sale of approximately 0.5 million barrels of petroleum products. The notional value of these agreements on December 31, 2006 was approximately $36.1 million.

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, 2006 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, 2006, 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, 2006, 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 management s assessment of our internal control over financial reporting as of December 31, 2006. The report, which expresses unqualified opinions on management s assessment and on the effectiveness of our internal control over financial reporting as of December 31, 2006, 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
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 management s assessment, included in the accompanying Management s Annual Report on Internal Control Over Financial Reporting, that Magellan Midstream Partners, L.P. maintained effective internal control over financial reporting as of December 31, 2006, 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. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of 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, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control 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, management s assessment that Magellan Midstream Partners, L.P. maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Magellan Midstream Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006 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, 2006 and 2005, and the related consolidated statements of income, partners capital and cash flows for each of the three years in the period ended December 31, 2006 of Magellan Midstream Partners, L.P. and our report dated February 26, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma

February 26, 2007

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, 2006 and 2005, and the related consolidated statements of income, partners capital and cash flows for each of the three years in the period ended December 31, 2006. 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, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 11 to the consolidated financial statements, effective December 31, 2006, Magellan Midstream Partners, L.P. adopted Statement of Financial Accounting Standard No. 158, Employers Accounting for Defined Benefit Pension and other Postretirement Plans .

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Magellan Midstream Partners, L.P. s internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2007, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma

February 26, 2007

MAGELLAN MIDSTREAM PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

(In thousands, except per unit amounts)

	Year Ended December 31, 2004	2005	2006
Transportation and terminals revenues	$ 419,117	$ 500,196	$ 558,301
Product sales revenues	275,769	636,209	664,569
Affiliate management fee revenues	488	667	690
Total revenues	695,374	1,137,072	1,223,560
Costs and expenses:			
Operating	179,657	229,795	244,526
Product purchases	255,599	582,631	605,341
Depreciation and amortization	41,845	56,307	60,852
Affiliate general and administrative	54,466	61,131	67,112
Total costs and expenses	531,567	929,864	977,831
Equity earnings	1,602	3,104	3,324
Operating profit	165,409	210,312	249,053
Interest expense	38,319	53,371	57,478
Interest income	(2,458)	(4,296)	(2,097)
Interest capitalized	(426)	(817)	(2,371)
Debt prepayment premium	12,666		
Write-off of unamortized debt placement costs	5,002		
Debt placement fee amortization	3,056	2,871	2,681
Other (income) expense	(953)	(300)	634
Net income	$ 110,203	$ 159,483	$ 192,728
Allocation of net income:			
Limited partners interest	$ 101,140	$ 135,579	$ 148,881
General partner s interest	9,063	23,904	43,847
Net income	$ 110,203	$ 159,483	$ 192,728
Basic net income per limited partner unit	$ 1.72	$ 2.04	$ 2.24
Weighted average number of limited partner units outstanding used for basic net income per unit calculation	58,716	66,361	66,361
Diluted net income per limited partner unit	$ 1.72	$ 2.03	$ 2.24
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation	58,844	66,625	66,613

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS

(In thousands)

	December 31, 2005	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 36,489	$ 6,390
Restricted cash	5,537	5,283
Accounts receivable (less allowance for doubtful accounts of $133 and $51 at December 31, 2005 and 2006, respectively)	49,373	51,730
Other accounts receivable	5,566	13,288
Affiliate accounts receivable	5,535	483
Inventory	78,155	91,550
Other current assets	5,034	8,294
Total current assets	185,689	177,018
Property, plant and equipment	2,116,143	2,260,608
Less: accumulated depreciation	506,626	557,869
Net property, plant and equipment	1,609,517	1,702,739
Equity investments	24,888	24,087
Long-term receivables	7,327	6,920
Long-term affiliate receivables	1,245	
Goodwill	24,430	23,945
Other intangibles (less accumulated amortization of $3,607 and $5,196 at December 31, 2005 and 2006, respectively)	11,652	8,633
Debt placement costs (less accumulated amortization of $6,911 and $9,592 at December 31, 2005 and 2006, respectively)	8,084	5,829
Other noncurrent assets	3,686	3,478
Total assets	$ 1,876,518	$ 1,952,649
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable	$ 25,508	$ 55,549
Affiliate accounts payable	5,821	11,008
Affiliate payroll and benefits	17,028	18,676
Accrued interest payable	9,628	9,266
Accrued taxes other than income	17,307	17,460
Environmental liabilities	30,840	34,952
Deferred revenue	17,522	22,901
Accrued product purchases	34,772	63,098
Current portion of long-term debt	14,345	270,839
Other current liabilities	13,124	14,640
Total current liabilities	185,895	518,389
Long-term debt	782,639	518,609
Long-term affiliate payable	10,091	8,133
Long-term affiliate pension and benefits	9,766	29,278
Other deferred liabilities	52,773	48,945
Environmental liabilities	27,364	22,813
Commitments and contingencies		

Partners capital:		
Common unitholders (60,681 units and 66,361 units outstanding at December 31, 2005 and 2006, respectively)	1,097,391	1,166,600
Subordinated unitholders (5,680 units outstanding at December 31, 2005)	67,925	
General partner	(355,271)	(341,267)
Accumulated other comprehensive loss	(2,055)	(18,851)
Total partners capital	807,990	806,482
Total liabilities and partners capital	$ 1,876,518	$ 1,952,649

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Year Ended December 31, 2004	2005	2006
Operating Activities:			
Net income	$ 110,203	$ 159,483	$ 192,728
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	41,845	56,307	60,852
Debt placement fee amortization	3,056	2,871	2,681
Debt prepayment premium	12,666		
Write-off of unamortized debt placement costs	5,002		
Loss on sale and retirement of assets	5,164	8,334	8,031
Gain on interest rate hedge	(953)		
Equity earnings	(1,602)	(3,104)	(3,324)
Distributions from equity investment	1,550	3,300	4,125
Equity method incentive compensation expense			1,770
Changes in operating assets and liabilities (Note 4)	59,570	(2,389)	37,816
Net cash provided by operating activities	236,501	224,802	304,679
Investing Activities:			
Purchases of marketable securities	(320,205)	(50,500)	
Sales of marketable securities	232,403	138,302	
Property, plant and equipment:			
Additions to property, plant and equipment	(53,545)	(92,791)	(168,544)
Proceeds from sale of assets	1,794	2,994	6,313
Changes in accounts payable			13,934
Equity investments	(25,032)		
Partial buyout of third-party supply agreement		(7,566)	
Acquisitions of businesses	(25,441)	(55,263)	
Acquisition of assets	(522,300)	(10,863)	
Net cash used by investing activities	(712,326)	(75,687)	(148,297)
Financing Activities:			
Distributions paid	(116,943)	(160,494)	(207,966)
Net borrowings under revolver		13,000	7,500
Borrowings under credit facility	50,000		
Payments on credit facility	(140,000)		
Borrowings under notes	799,182		
Payments on notes	(478,000)	(15,100)	(14,345)
Capital contributions by affiliate	14,807	20,087	28,742
Sales of common units to public (less underwriters commissions and payment of formation and offering costs)	286,523		
Debt placement costs	(8,394)		(426)
Payment of debt prepayment premium	(12,666)		
Other	(208)	48	14
Net cash provided by (used in) financing activities	394,301	(142,459)	(186,481)
Change in cash and cash equivalents	(81,524)	6,656	(30,099)
Cash and cash equivalents at beginning of period	111,357	29,833	36,489
Cash and cash equivalents at end of period	$ 29,833	$ 36,489	$ 6,390

Supplemental non-cash investing and financing transactions:						
Contributions by affiliate of property, plant and equipment and other assets and liabilities to partners capital	$	2,396	$		$	

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, December 31, 2003	$ 737,715	$ 135,085	$ (373,880)	$ (771)	$ 498,149
Comprehensive income:					
Net income	86,136	15,004	9,063		110,203
Amortization of loss on cash flow hedges				9	9
Net loss on cash flow hedges				(1,160)	(1,160)
Total comprehensive income					109,052
Conversion of subordinated units to common units (2.8 million units)	33,024	(33,024)			
Issuance of common units to public (11.6 million units)	286,523				286,523
Affiliate capital contributions			12,411		12,411
Distributions	(84,414)	(15,832)	(16,697)		(116,943)
Other	(71)	(11)	(1)		(83)
Balance, December 31, 2004	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	(148,496)	(3,138)	(56,332)		(207,966)
Equity method incentive compensation expense	1,770				1,770
Other	14				14

Balance, December 31, 2006	$ 1,166,600	$	$ (341,267)	$ (18,851)	$ 806,482

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 were formed in August 2000 as a Delaware limited partnership to own, operate and acquire a diversified portfolio of complementary energy assets. Magellan GP, LLC, a Delaware limited liability company, serves as our general partner and through December 31, 2006 owned a 2% general partner interest in us and owns all of our incentive distribution rights. See Note 24 Subsequent Events for a discussion of changes in our general partner s ownership interest in us after December 31, 2006. Magellan Midstream Holdings, L.P. (MGG) owns all of the membership interests of Magellan GP, LLC.

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 45 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, diesel fuels, 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, airlines and other end-users. As part of a pipeline system acquisition completed during October 2004, we assumed 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 are included in the petroleum products pipeline segment. We acquired an ownership interest in Osage Pipe Line Company, LLC (Osage Pipeline) during 2004. This system includes the 135-mile Osage pipeline, which 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 petroleum products blending operation is 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 and heavy oils and feedstocks. The terminal network consists of marine terminals and inland terminals. In September 2005, we acquired a refined petroleum products terminal near Wilmington, Delaware (see Note 6 Acquisitions), increasing the number of marine terminals we operate to seven. Five of our marine terminal facilities are located along the Gulf Coast and two marine terminal facilities are located on the East Coast. As of December 31, 2006, we owned 29 inland terminals located primarily in the southeastern United States.

Ammonia Pipeline System. The ammonia pipeline system consists of an 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.

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 includes cash held by us pursuant to the terms of the Magellan Pipeline Company, L.P. (Magellan Pipeline) notes (see Note 13 Debt).

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.

Trade Receivables 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 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.

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 and assets recorded in transactions designated as the acquisition of a business. Impaired assets are recorded at fair value on the last impairment evaluation date for which an adjustment was required. Assets recorded in transactions designated as the acquisition of a business are recorded at the fair value of the assets acquired.

Assets are depreciated individually on a straight-line basis over their useful lives. We assign these lives based on reasonable estimates when the 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 individual components of certain assets, such as tanks,

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

are grouped together into a composite asset. Those assets are depreciated using a composite rate. The range of depreciable lives by asset category is detailed in Note 8 Property, Plant and Equipment.

The carrying value of property, plant and equipment sold or retired and the related accumulated depreciation is removed from the accounts and any associated gains or losses are recorded in the 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 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. We capitalize interest for capital projects with expenditures over $0.5 million that require three months or longer to complete. Expenditures for maintenance, repairs and minor replacements are charged to operating expense in the period incurred.

Asset Retirement Obligation. We have adopted Statement of Financial Accounting Standard (SFAS) No. 143, Accounting for Asset Retirement Obligations. 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. In March 2005, the Financial Accounting Standards Board (FASB) issued Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations (as amended). 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 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 exceeds 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 2004, 2005 or 2006.

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 at December 31, 2005 and 2006 was $24.4 million and $23.9 million, respectively.

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 general and administrative (G&A) costs, with an assumed growth of 3.0% per year, (iii) weighted-average cost of capital of 10.25% 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, 2005 or 2006. If impairment were to occur, the amount of the impairment recognized would be determined by subtracting the implied fair value of the reporting unit goodwill from the carrying amount of the goodwill.

All of our other intangible assets are being amortized over their useful lives. 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 2004, 2005 or 2006. Other intangible assets are amortized on a straight-line basis over their estimated useful lives of 5 years up to 25 years. The weighted-average asset lives of our other intangible assets at December 31, 2006 was approximately 10 years. Amortization of other intangible assets was $1.3 million, $1.4 million and $1.6 million during 2004, 2005 and 2006, respectively.

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.

Impairment of Long-Lived Assets. We have adopted SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. In accordance with this Statement, we evaluate our long-lived assets of identifiable business activities, other than those held for sale, for impairment when events or changes in circumstances indicate, in management s judgment, that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on management s estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. The amount of the impairment recognized is calculated as the excess of the carrying amount of the asset over the fair value of the assets, as determined either through reference to similar asset sales or by estimating the fair value using a discounted cash flow approach.

Long-lived assets to be disposed of through sales of assets 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.

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 2004 or 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, which we may close in 2007. This impairment charge is 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 17 Segment Disclosures for the year ended December 31, 2006. The carrying value of the

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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.

Capitalization of Interest. Interest on borrowed funds is capitalized on projects during construction based on the approximate average interest rate of our debt. We capitalize interest on all construction projects requiring three months or longer to complete with total costs exceeding $0.5 million.

Pension and Postretirement Medical and Life Benefit Obligations. Prior to December 2005, MGG maintained defined benefit plans and a defined contribution plan, which provided retirement benefits to substantially all of its employees. In December 2005, the employees of MGG were transferred to Magellan Midstream Holdings GP, LLC (MGG GP), which is MGG s general partner. Accordingly, the defined benefit plans and defined contribution plan were also transferred to MGG GP (see Note 11 Employee Benefit Plans). At December 31, 2005, the affiliate pension and postretirement medical and life liabilities reported on our consolidated balance sheets represented the funded status of the present value of benefit obligations net of unrecognized prior service costs/credits and unrecognized actuarial gains/losses of the aforementioned plans. In 2006 we adopted SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans and, as of December 31, 2006, our pension and postretirement benefit obligations represent the funded status of the present value of benefit obligations of the aforementioned plans.

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 $6.8 million and $8.0 million at December 31, 2005 and 2006, 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 accrued affiliate payroll and benefits balances of the consolidated balance sheets.

Derivative Financial Instruments. We account for hedging activities 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. Furthermore, we assess the creditworthiness of the counterparties to manage against the risk of default. If we

MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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, 2006, we had commitments under future contracts for product purchases that will be accounted for as normal purchases totaling approximately $1.7 million. Additionally, we had commitments under future contracts for product sales that will be accounted for as normal sales totaling approximately $36.1 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 hedges 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 other comprehensive income.

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 and 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.

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, we had terminalling agreements with a third-party customer under which we provided 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. Under these agreements, we recognized the storage rental and throughput fees as the services were performed; however, we would not have received any revenue from the variable fee if the net trading profits had fallen below a specified amount or were negative. Therefore, the income we earned related to the shared trading profits was not determinable until the end of the contract term. We have elected to 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 one contract expired on January 31, 2006, and an additional $3.0 million of terminalling revenues when a second contract expired on December 31, 2006.

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. We are the primary obligor on these transactions and we assume credit risk and risk of ownership for the associated products. Accordingly, under Emerging Issues Task Force (EITF) Issue No. 99-19, Recording Revenue Gross as a Principle Versus Net as an Agent, we have included the gross amounts of these transactions in our consolidated statements of income. Amounts associated with these buy / sell arrangements included in product sales revenues and in product purchases were $23.1 million, $2.4 million and $0.7 million, respectively, for the years ended December 31, 2004, 2005 and 2006. Had these transactions been reported net, our product sales and

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

product purchases during 2004, 2005 and 2006 would have been reduced by $23.1 million, $2.4 million and $0.7 million, respectively.

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. See *Reimbursement of G&A Expense* in Note 12 Related Party Transactions for a detailed discussion of this matter. 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 its directors and certain employees of MGG GP who support us. These awards were accounted for as prescribed in SFAS No. 123(R), which required us to account for all of our equity-based incentive award grants prior to January 1, 2006 using the fair value method as defined in SFAS No. 123 instead of our previous methodology of using the intrinsic value method as defined in Accounting Principles Board (APB) Opinion No. 25. Due to the structure of our award grants prior to January 1, 2006, we recognized compensation expense under APB No. 25 in much the same manner as that required under SFAS No. 123; therefore, the impact of the change from accounting for the award grants under APB No. 25 to SFAS No. 123 was insignificant to our consolidated statements of income. The unit-based awards granted during 2006 have been accounted for under the provisions of SFAS No. 123(R).

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 of unit award grants, which generally is the vesting period remaining on the grant date. Fair value for equity awards is calculated as the closing price of our common units representing limited partner interests in us (limited partner units) on the grant date reduced by the present value of expected per-unit distributions to be paid during the requisite service period of the unit award grants. 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 rendered 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 double 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 independently of any potential claim for recovery. Accruals related to environmental matters are generally determined based on site-specific plans for remediation, taking into account currently available facts, existing technologies and presently enacted laws and regulations. Accruals for environmental matters reflect our prior remediation experience and include an estimate for costs such as fees paid to contractors and outside engineering, consulting and law firms. Furthermore, costs include compensation and benefit expense of internal employees directly involved in remediation efforts. We maintain selective insurance coverage, which may cover

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

all or portions of certain environmental expenditures. Receivables are recognized in cases where the realization of reimbursements of remediation costs is considered probable.

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 18 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 will impose a partnership-level tax on us beginning in 2007 based on the financial results of our assets apportioned to the state of Texas. We estimate that our tax obligation under this law will be approximately $3.0 million for the 2007 fiscal year. This tax will be reflected as provision for income taxes in our results of operations for 2007 and beyond.

***Allocation of Net Income*.** For purposes of calculating earnings per unit, we allocate net income to our general partner and limited partners each quarter 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 21 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 5 Allocation of Net Income). For periods where net income exceeds distributions, net income is allocated to our general and limited partners each quarter based on their proportionate share of pro forma cash distributions assuming that distributions for the period were equal to net income, with adjustments made for any charges specifically allocated to our general partner.

For purposes of determining capital balances, 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.

Net Income Per Unit. Basic net income per unit is determined each quarter by dividing the limited partners allocation of net income by the weighted-average number of limited partner units outstanding for the period. Phantom units with distribution equivalent rights that have been awarded to directors of our general partner are included in the weighted-average number of limited partner units outstanding. Diluted net income per unit for each quarter is the same calculation, except the weighted-average units outstanding include any dilutive effect of other phantom unit grants.

Comprehensive Income. We account for comprehensive income in accordance with SFAS No. 130, Reporting Comprehensive Income. Our comprehensive income is determined based on net income adjusted for

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. SFAS No. 130 requires us to report total comprehensive income, which we have included with our consolidated statement of partners capital.

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, 2004	$ (771)	$	$	$ (771)
Amortization of loss on cash flow hedges	9			9
Net loss on cash flow hedges	(1,160)			(1,160)
Balance, December 31, 2004	(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 hedge	236			236
Adjustment to additional minimum pension liability		343		343
Adjustment to recognize the funded status of the postretirement benefit plans			(17,587)	(17,587)
Balance, December 31, 2006	$ (1,264)	$	$ (17,587)	$ (18,851)

Recent Accounting Standards. 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 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 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 were 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 be no

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longer 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 are 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 have an impact on 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. 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 are considering adopting this standard for 2007 but have not yet made a final decision. The adoption of this standard will 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 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* 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 February 2006 and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In November 2005, the FASB issued FSP No. FAS 115-1 and FAS 124-1, The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments. This FSP addresses the determination as to when an investment is considered impaired, whether that impairment is other than temporary and the measurement of an impairment loss. This FSP also includes accounting considerations subsequent to the recognition of an other-than-temporary impairment and requires certain disclosures about unrealized losses that have not been recognized as other-than-temporary impairments. The guidance in this FSP amends FASB Statement No. 115, Accounting for Certain Investments in Debt and Equity Securities, FASB Statement No. 124, Accounting for Certain Investments Held by Not-for-Profit Organizations, and APB No. 18, The Equity Method of Accounting for Investments in Common Stock. The guidance in this FSP is to be applied to reporting periods beginning after December 15, 2005. We adopted this FSP on January 1, 2006, and its adoption did not have a material impact on our financial position, results of operations or cash flows.

In October 2005, the FASB issued FSP No. 13-1, Accounting for Rental Costs Incurred During a Construction Period. This FSP requires entities who incur rental costs associated with operating leases to

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

expense such costs as a continuing operating expense. This FSP is required to be implemented beginning January 1, 2006, with early adoption permitted. We adopted the FSP on January 1, 2006, and its adoption did not have a material impact on our financial position, results of operations or cash flows.

In September 2005, the FASB issued EITF issue No. 04-13, Accounting for Purchases and Sales of Inventory With the Same Counterparty. In EITF No. 04-13, the FASB reached a tentative conclusion that inventory purchases and sales transactions with the same counterparty that are entered into in contemplation of one another should be combined for purposes of applying APB No. 29, Accounting for Nonmonetary Transactions. The tentative conclusions reached by the FASB are required to be applied to transactions completed in reporting periods beginning after March 15, 2006. We adopted this EITF on March 16, 2006, and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In May 2005, the FASB published SFAS No. 154, Accounting Changes and Error Corrections. SFAS No. 154 requires retrospective application to prior periods financial statements of every voluntary change in accounting principle unless it is impracticable to do so. SFAS No. 154 also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. SFAS No. 154 requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle, such as a change in nondiscretionary profit-sharing payments resulting from an accounting change, should be recognized in the period of the accounting change. We adopted this SFAS No. 154 on January 1, 2006, and its adoption did not have a material impact on our financial position, results of operations or cash flows.

In March 2005, the FASB issued FIN No. 47, Accounting for Conditional Asset Retirement Obligations (as amended). FIN No. 47 clarified that the term *conditional asset retirement obligation* as used in SFAS No. 143, Accounting for Asset Retirement Obligations, refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. Accordingly, 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 reasonably estimated. The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred generally upon acquisition, construction, or development and (or) through the normal operation of the asset. Uncertainty about the timing and (or) method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. SFAS No. 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. This Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN No. 47 was required to be adopted no later than the end of fiscal years ending after December 15, 2005, with retrospective application for interim financial information permitted. We adopted FIN No. 47 in March 2005, and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In December 2004, the FASB issued a revision to SFAS No. 123, Share-Based Payment, as amended, referred to as SFAS No. 123(R). This Statement and subsequent amendments establishes accounting standards for transactions in which an entity exchanges its equity instruments for goods or services. This SFAS requires that all equity-based compensation awards to employees be recognized in the income statement based on their fair values, eliminating the alternative to use APB No. 25 s intrinsic value method. SFAS No. 123(R) was effective as of the beginning of the first interim period that began after December 31, 2005. SFAS No. 123(R) applied to all awards granted after the required effective date but was not to be applied to awards granted in periods before the required effective date except to the extent that awards from prior periods were modified,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

repurchased or cancelled after the required effective date. We adopted SFAS No. 123(R) on January 1, 2006, using the modified prospective application method. Under the modified prospective method, we were required to account for all of our equity-based incentive awards granted prior to January 1, 2006 using the fair value method as defined in SFAS No. 123 instead of our then-current methodology of using the intrinsic value method as defined in APB No. 25. Due to the structure of our award grants, we recognized compensation expense under APB No. 25 in much the same manner as that required under SFAS No. 123. Consequently, for the awards granted prior to January 1, 2006, the initial adoption and application of SFAS No. 123(R) did not have a material impact on our financial position, results of operations or cash flows.

3. Debt and Equity Offerings

During May 2004, we executed a refinancing plan to improve our credit profile and increase our financial flexibility by removing all of the secured debt from our capital structure. The proceeds and use of cash from the transactions associated with this refinancing plan were as follows:

Total proceeds from our 2.0 million common unit equity offering at a price of $23.80 per unit were $47.6 million. Associated with this offering, our general partner contributed $1.0 million to us to maintain its 2% general partner interest. Of the proceeds received, $2.0 million was used to pay underwriting discounts and commissions. Legal, professional and other costs associated with the equity offering were approximately $0.2 million.

Total proceeds from the note issuance were $249.5 million. Of the proceeds received from the note issuance, $1.8 million was used to pay underwriting discounts and commissions and $0.8 million was used to pay legal, professional and other fees.

We used the total net proceeds of $293.3 million from these equity and debt offerings as follows:

- repaid all of the outstanding $178.0 million principal amount of Series A senior notes (see Note 13 Debt for a description of these notes) issued by Magellan Pipeline;
- paid $12.7 million of prepayment premiums associated with the early repayment of the Magellan Pipeline notes;
- repaid the $90.0 million outstanding principal balance of our then outstanding term loan;
- paid $1.9 million to Magellan Pipeline s Series B noteholders (see Note 13 Debt for a description of these notes) to release the collateral held by them and $0.8 million of associated legal costs;
- paid $0.9 million of legal and professional fees associated with establishing a new unsecured revolving credit facility (see Note 13 Debt for a description of this facility); and
- partially replenished the cash used to fund acquisitions completed in 2003 and early 2004.

In conjunction with the repayment of the Magellan Pipeline Series A senior notes and our term loan in May 2004, we recognized $5.0 million of expense associated with the write-off of unamortized debt placement costs.

On October 1, 2004, we completed an acquisition of assets from Shell Pipeline Company LP and Equilon Enterprises LLC doing business as Shell Oil Products US (collectively Shell) (see Note 6 Acquisitions). The debt and equity offerings discussed below were completed as part of the financing requirements associated with that acquisition:

During August 2004, in anticipation of the acquisition, we issued and sold 3.6 million limited partner units. Total proceeds from the sale, at a price of $24.89 per unit, were $89.6 million. Associated with

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

this offering, our general partner made a $1.8 million contribution to us to maintain its 2% general partner interest. Net proceeds, after underwriter discounts of $3.8 million and offering expenses of approximately $0.5 million, were $87.1 million;

On October 1, 2004, we borrowed $300.0 million under a short-term acquisition facility and $50.0 million under our revolving credit facility to help finance this acquisition. We incurred debt issuance costs of $0.1 million associated with the $300.0 million short-term acquisition facility;

On October 4, 2004, we issued and sold 5.2 million limited partner units. The units were sold at a price of $27.25 for total proceeds of $141.7 million. Associated with this offering, our general partner contributed $2.9 million to us to maintain its 2% general partner interest. Of the proceeds received, $6.0 million was used to pay underwriting discounts and commissions. Legal, professional and other costs associated with the equity offering were approximately $0.3 million. We used the net proceeds of $138.3 million to repay a portion of the amounts borrowed under the short-term acquisition facility. The underwriters exercised their over-allotment option associated with the October 2004 offering and on November 1, 2004, we issued and sold an additional 0.8 million limited partner units. Total proceeds from this sale were $21.3 million, of which we paid $0.9 million for underwriting discounts and commissions. Our general partner made an additional $0.4 million contribution to maintain its 2% general partner interest. The net proceeds of $20.8 million from the over-allotment sale were used to replace cash we used to pay for other investments; and

On October 15, 2004, we issued $250.0 million of senior notes. The notes were issued for the discounted price of 99.9%, or $249.7 million. The net proceeds from this debt issuance, after underwriter discounts of $1.8 million and debt issuance fees of $0.3 million, were $247.6 million. We used these net proceeds to: (i) repay the remaining $161.7 million outstanding under the acquisition facility (the original $300.0 million borrowed less $138.3 million partial repayment from the October 4, 2004 equity offering discussed above) plus accrued interest costs of $0.2 million, and (ii) repay the $50.0 million amount previously borrowed under the revolver plus accrued interest costs of $0.1 million. The remaining proceeds of $35.6 million from this debt offering were used to replenish cash used in the acquisition of assets from Shell.

4. Consolidated Statements of Cash Flows

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

	Year Ended December 31,		
	2004	**2005**	**2006**
Accounts receivable and other accounts receivable	$ (21,646)	$ 901	$ (8,843)
Affiliate accounts receivable	687	3,102	5,052
Inventory	3,864	(34,758)	(13,395)
Accounts payable	(380)	5,114	16,107
Affiliate accounts payable	158	5,208	5,187
Affiliate payroll and benefits	4,532	(2,247)	1,488
Accrued interest payable	1,664	(232)	(362)
Accrued taxes other than income	(1,074)	1,028	153
Accrued product purchases	5,728	17,459	28,326
Accrued product shortages	7,507	(7,507)	
Cash deposit	14,000	(1,500)	1,000
Current and noncurrent environmental liabilities	27,894	(3,006)	(439)
Other current and noncurrent assets and liabilities	16,636	14,049	3,542
Total	$ 59,570	$ (2,389)	$ 37,816

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. We have excluded these non-cash amounts from the statement of cash flows.

5. 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):

	2004	2005	2006
Allocation of net income to general partner:			
Net income	$ 110,203	$ 159,483	$ 192,728
Direct charges to general partner:			
Reimbursable G&A costs	6,397	3,294	1,665
Other G&A Costs[(a)]			3,000
Previously indemnified environmental charges	1,351	8,502	8,987
Transition charges	823		
Total direct charges to general partner	8,571	11,796	13,652
Income before direct charges to general partner	118,774	171,279	206,380
General partner s share of income[(b)]	14.85%	20.84%	27.86%
General partner s allocated share of net income before direct charges	17,634	35,700	57,499
Direct charges to general partner	(8,571)	(11,796)	(13,652)
Net income allocated to general partner	$ 9,063	$ 23,904	$ 43,847
Net income	$ 110,203	$ 159,483	$ 192,728
Less: net income allocated to general partner	9,063	23,904	43,847
Net income allocated to limited partners	$ 101,140	$ 135,579	$ 148,881

(a) A former executive officer of our general partner had an investment in MGG Midstream Holdings, L.P., which is an affiliate of ours and our general partner. This former executive officer left the company during the fourth quarter of 2006 and at that time we were allocated $3.0 million of G&A compensation expense associated with certain distribution payments made by MGG Midstream Holdings, L.P. to this individual over the past three years. Because the limited partners did not share in these costs, we allocated all of this expense to our general partner.

(b) For those periods when net income exceeds distributions, net income is allocated between the general partner and limited partners each quarter based on the contractually-determined proportion of cash distributions paid, adjusted for any direct charges to the general partner. Because our net income for the second and fourth quarters of 2006 exceeded cash distributions, under the two class method of computing earnings per share, as prescribed by SFAS No. 128, Earnings Per Share , earnings were allocated to the general partner and limited partners assuming that all of the 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.

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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:

	2004	2005	2006
Allocation of net income to general partner:			
Net income	$ 110,203	$ 159,483	$ 192,728
Direct charges to general partner:			
Reimbursable G&A costs	6,397	3,294	1,665
Other G&A costs			3,000
Previously indemnified environmental charges	1,351	8,502	8,987
Transition charges	823		
Total direct charges to general partner	8,571	11,796	13,652
Income before direct charges to general partner	118,774	171,279	206,380
General partner s share of income[(a)]	14.85%	20.84%	26.77%
General partner s allocated share of net income before direct charges	17,634	35,700	55,246
Direct charges to general partner	(8,571)	(11,796)	(13,652)
Net income allocated to general partner	$ 9,063	$ 23,904	$ 41,594
Net income	$ 110,203	$ 159,483	$ 192,728
Less: net income allocated to general partner	9,063	23,904	41,594
Net income allocated to limited partners	$ 101,140	$ 135,579	$ 151,134

(a) We allocate net income to our general partner and limited partners each quarter 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.

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. During 2004, we and our general partner entered into an agreement with a former affiliate to settle certain of its indemnification obligations to us (see Note 18 Commitments and Contingencies). Following this settlement, the expenses associated with these previously indemnified costs are allocated directly to our general partner. We have received $82.5 million of the $117.5 million settlement and the final $35.0 million installment payment is due on July 1, 2007. Accordingly, we will continue to allocate amounts associated with previously indemnified costs to our general partner. The transition charges represented our costs for transitioning from a former affiliate to a stand-alone enterprise in excess of the amount we were contractually required to pay. Consequently, we allocated all of these costs directly to our general partner.

6. Acquisitions

The acquisitions discussed below were accounted for as acquisitions of businesses. These acquisitions were accounted for under the purchase method and the assets acquired and liabilities assumed were recorded at their estimated fair market values as of the respective acquisition dates.

Petroleum Products Terminals

On January 29, 2004, we acquired ownership in 14 petroleum products terminals located in the southeastern United States. The results of operations from this acquisition have been included with the petroleum products

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

terminals segment results since its acquisition date. We paid $24.8 million for these facilities, incurred $0.6 million of closing costs and assumed $3.8 million of environmental liabilities. We previously owned a 79% interest in eight of these terminals and purchased the remaining ownership interest from Murphy Oil USA, Inc. In addition, the acquisition included sole ownership of six terminals that were previously jointly owned by Murphy Oil USA, Inc. and Colonial Pipeline Company. The allocation of the purchase price to assets acquired and liabilities assumed was as follows (in thousands):

Purchase price:	
Cash paid, including transaction costs	$ 25,441
Environmental liabilities assumed	3,815
Total purchase price	$ 29,256
Allocation of purchase price:	
Property, plant and equipment	$ 29,256

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 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Pro Forma Information (unaudited)

The following summarized pro forma consolidated income statement information assumes that the two petroleum product terminals acquisitions 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 these acquisitions as of the periods 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, 2004			Year Ended December 31, 2005		
	As Reported	Pro Forma Adjustments	Pro Forma	As Reported	Pro Forma Adjustments	Pro Forma
Revenues	$ 695,374	$ 8,903	$ 704,277	$ 1,137,072	$ 5,585	$ 1,142,657
Net income	$ 110,203	$ 3,881	$ 114,084	$ 159,483	$ 2,508	$ 161,991
Basic net income per limited partner unit	$ 1.72	$ 0.06	$ 1.78	$ 2.04	$ 0.03	$ 2.07
Diluted net income per limited partner unit	$ 1.72	$ 0.05	$ 1.77	$ 2.03	$ 0.03	$ 2.06
Weighted average number of limited partner units used for basic net income per unit calculation	58,716	58,716	58,716	66,361	66,361	66,361
Weighted average number of limited partner units used for diluted net income per unit calculation	58,844	58,844	58,844	66,625	66,625	66,625

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

The following acquisitions were accounted for as acquisitions of assets:

Pipeline Asset Acquisition. On October 1, 2004, we acquired more than 2,000 miles of petroleum products pipeline system assets from Shell for approximately $488.9 million. In addition to the purchase price, we paid approximately $30.1 million for inventory related to a third-party supply agreement under which we received $14.0 million cash collateral, assumed approximately $57.6 million of existing liabilities and incurred approximately $3.3 million for transaction costs. During June 2004, we paid Shell $24.6 million as earnest money associated with the acquisition, which was applied against the purchase price at closing.

The assets we acquired from Shell had not been operated historically as a separate division or subsidiary. Shell operated these assets as part of its more extensive transportation and terminalling and crude oil and refined products operations. As a result, Shell did not maintain complete and separate financial statements for these assets as an independent business unit. We have made significant changes to the assets, including construction of additional connections between the acquired assets and our existing infrastructure, resulting in significant operating differences and revenues generated. Additionally, differences in our operating approach have resulted in obtaining different revenues and results of operations than those historically achieved by Shell. For these reasons, this acquisition constituted an acquisition of assets, and not of a business.

The results of operations from this acquisition have been included in our results since October 1, 2004. We integrated most of the assets acquired from Shell into the operations of our petroleum products pipeline system

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

utilizing our existing accounting, financial reporting and measurement and control systems. In order to facilitate this integration, we entered into a transition services agreement with Shell which terminated at the end of February 2005. We also entered into transportation, terminalling and supply agreements with third parties, including Shell, for the refined petroleum products pipelines, terminals and system storage facilities that we acquired. We charge applicable tariffs and fees for transportation and terminalling services with respect to these assets in order to generate revenues and cash for distribution to our general partner and unitholders.

Assumed Liabilities. In conjunction with the acquisition, we agreed to assume from Shell a third-party supply agreement, the terms of which management believed to be significantly below-market rates, and we recognized the $43.5 million fair value of the supply agreement as an increase in the recorded book value of the assets acquired with an offsetting liability. This liability was reduced $7.6 million in conjunction with our acquisition of a terminal in Aledo, Texas (see *Petroleum Products Pipeline Terminals* below for further discussion of this matter). The unamortized amount of this liability at December 31, 2005 and 2006 was $32.0 million and $29.5 million, respectively.

In 2003, Shell entered into a consent decree with the United States Environmental Protection Agency (EPA) arising out of a June 1999 incident unrelated to the assets we acquired from Shell. In order to resolve Shell s civil liability for the incident, Shell agreed to pay civil penalties and to comply with certain terms set out in the consent decree. These terms include requirements for testing and maintenance of a number of Shell s pipelines, including two of the pipelines we acquired, the creation of a damage prevention program, submission to independent monitoring and various reporting requirements. The consent decree imposes penalties for non-compliance for a period of at least five years from the date of the consent decree. Under our purchase agreement with Shell, we agreed, at our expense, to complete any remaining remediation work required under the consent decree with respect to the acquired pipelines. We recognized a liability of approximately $8.6 million associated with this agreement. Shell has agreed to retain responsibility under the consent decree for the ongoing independent monitoring obligations. The unamortized amount of this liability at December 31, 2005 and 2006 was $5.6 million and $2.6 million, respectively.

As part of the acquisition, Shell agreed to retain liabilities and expenses related to active environmental remediation projects, other than those relating to the consent decree discussed above. We recorded approximately $2.1 million of environmental liabilities related to our estimates for remediation sites that Shell did not consider to be currently active. Also, upon closing of this acquisition, we were assessed a use tax liability of $1.1 million by the State of Oklahoma.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Allocation of Purchase Price. The purchase price allocation of the assets acquired and liabilities assumed from Shell was as follows (in millions):

Purchase price:	
Cash paid for pipeline systems	$ 488.9
Cash paid for inventory	30.1
Capitalized portion of transaction costs	3.3
Liabilities assumed:	
Fair value of third-party supply agreement	43.5
Consent decree	8.6
Property tax liability	2.3
Environmental	2.1
Use tax liability	1.1
Total liabilities assumed	57.6
Total purchase price	$ 579.9
Allocation of purchase price:	
Property, plant and equipment	$ 548.3
Inventory	30.1
Prepaid assets	1.5
Total purchase price	$ 579.9

Financing. The transactions completed to finance the assets acquired from Shell are discussed in detail in Note 3 Debt and Equity Offerings.

Agreements with Shell. In connection with our acquisition of this refined petroleum products pipeline system, we entered into three-year terminalling and transportation agreements and a five-year storage lease agreement with Shell for a combined minimum revenue commitment averaging approximately $28.1 million per year through September 30, 2007 and approximately $0.8 million per year thereafter through September 30, 2009. Management concluded that these contracts reflected market prices in effect at the time.

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)

7. Inventory

Inventories at December 31, 2005 and 2006 were as follows (in thousands):

	December 31,	
	2005	2006
Refined petroleum products	$ 56,680	$ 45,839
Natural gas liquids	9,693	28,848
Transmix	9,589	14,449
Additives	1,805	2,026
Other	388	388
Total inventories	$ 78,155	$ 91,550

The increase in the natural gas liquids inventory at December 31, 2006 compared to December 31, 2005 is the result of purchasing significantly higher volumes of natural gas liquids used in our petroleum products blending operation during the fourth quarter of 2006 due to favorable product prices.

8. Property, Plant and Equipment

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

	December 31,		Estimated Depreciable
	2005	2006	Lives
Construction work-in-progress	$ 28,657	$ 67,330	
Land and rights-of-way	51,476	53,400	
Carrier property	1,370,793	1,400,326	24 50 years
Buildings	12,264	12,717	20 53 years
Storage tanks	285,884	306,966	20 40 years
Pipeline and station equipment	100,398	114,298	4 59 years
Processing equipment	221,804	255,846	3 53 years
Other	44,867	49,725	3 48 years
Total	$ 2,116,143	$ 2,260,608	

Carrier property is defined as pipeline assets regulated by the FERC. Other includes capitalized interest at December 31, 2005 and 2006 of $19.2 million and $19.3 million, respectively. Depreciation expense for the years ended December 31, 2004, 2005 and 2006 was $40.5 million, $54.9 million and $59.3 million, respectively.

9. Equity Investments

Effective March 2, 2004, we acquired a 50% ownership in Osage Pipeline for $25.0 million. The remaining 50% interest is owned by the National Cooperative Refinery Association in McPherson, Kansas (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 is included with our petroleum products pipeline system segment.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We use the equity method of accounting for this investment. Summarized financial information for Osage Pipeline is presented below (in thousands):

	March 2, 2004 Through December 31, 2004	Year Ended December 31, 2005	Year Ended December 31, 2006
Revenue	$ 9,814	$ 12,573	$ 14,446
Net income	$ 4,310	$ 7,537	$ 7,976

The condensed balance sheet for Osage Pipeline as of December 31, 2005 and 2006 is presented below (in thousands):

	December 31, 2005	December 31, 2006
Current assets	$ 4,767	$ 5,015
Noncurrent assets	$ 4,535	$ 4,278
Current liabilities	$ 431	$ 697
Members equity	$ 8,871	$ 8,596

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

	December 31, 2005	December 31, 2006
Investment at beginning of period	$ 25,084	$ 24,888
Earnings in equity investment:		
Proportionate share of earnings	3,768	3,988
Amortization of excess investment	(664)	(664)
Net earnings in equity investment	3,104	3,324
Cash distributions	(3,300)	(4,125)
Equity investment at end of period	$ 24,888	$ 24,087

Our investment in Osage Pipeline included an excess net investment amount of $21.7 million. Excess investment is the amount by which our initial investment exceeded our proportionate share of the book value of the net assets of the investment. The unamortized excess net investment amount at December 31, 2005 and 2006 was $20.5 million and $19.8 million, respectively, and represents additional value of the underlying identifiable assets.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Major Customers and Concentration of Risks

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 both our petroleum products pipeline system and petroleum products terminals segments. Customer A purchased petroleum products from us pursuant to a third-party supply agreement we assumed in connection with our pipeline system acquisition in October 2004. In August 2006, this third-party supply agreement was assigned to Customer B. No other customer accounted for more than 10% of our consolidated total revenues for 2004, 2005 or 2006. 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.

	2004	2005	2006
Customer A	13%	42%	29%
Customer B	0%	0%	18%
Customer C	19%	9%	11%
Total	32%	51%	58%

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 are generally unsecured, and the financial condition and creditworthiness of customers are periodically evaluated. We have the ability with many of our pipeline and terminals contracts to sell stored customer products to recover unpaid receivable balances, if necessary. We also require additional security, as considered necessary.

Since December 24, 2005, the employees assigned to conduct our operations were employees of MGG GP. Prior to December 24, 2005, the employees assigned to conduct our operations were employees of MGG. On December 24, 2005, MGG transferred all of its employees to its general partner, MGG GP. As of December 31, 2006, MGG GP employed approximately 1,064 employees. We consider our employee relations to be good.

At December 31, 2006, the labor force of 569 employees assigned to our petroleum products pipeline system was concentrated in the central United States. Approximately 38% of these employees were represented by the United Steel Workers Union and covered by collective bargaining agreements that extend through January 31, 2009. The labor force of 236 employees assigned to our petroleum products terminals operations at December 31, 2006 was primarily concentrated in the southeastern and Gulf Coast regions of the United States. On August 10, 2006, the 27 non-supervisory employees at our New Haven, Connecticut terminal elected the International Union of Operating Engineers as their bargaining agent and we are currently in the process of negotiating an agreement with these employees. Our ammonia pipeline is operated by a third-party contractor and no employees are specifically assigned to those operations.

11. Employee Benefit Plans

On January 1, 2004, MGG assumed sponsorship of a union pension plan for certain hourly employees. Additionally, MGG began sponsorship of a pension plan for certain non-union employees, a postretirement benefit plan for selected employees and a defined contribution plan effective January 1, 2004. The sponsorship of these plans was transferred from MGG to MGG GP on December 24, 2005. 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 obligation of MGG GP s pension plans and its postretirement medical and life benefit plan. The effect of adopting SFAS No. 158 on amounts reported in our consolidated balance sheets is described later in this note. SFAS No. 158 prohibited retroactive application of this accounting standard.

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, 2005 and 2006. The table also presents a reconciliation of the funded status of these benefits to the amount recorded in the consolidated balance sheet at December 31, 2005 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2005	2006	2005	2006
Change in affiliate benefit obligation:				
Affiliate benefit obligation at beginning of year	$ 33,897	$ 39,122	$ 12,999	$ 19,280
Service cost	4,215	5,587	530	469
Interest cost	1,866	2,206	994	834
Plan participants contributions			39	55
Actuarial loss	1,199	332	4,834	720
Plan amendment[(a)]				(6,159)
Benefits paid	(2,055)	(3,398)	(116)	(195)
Affiliate benefit obligation at end of year	39,122	43,849	19,280	15,004
Change in plan assets:				
Fair value of plan assets at beginning of year	22,146	25,465		
Employer contributions	4,813	5,259	77	140
Plan participants contributions			39	55
Actual return on plan assets	561	2,090		
Benefits paid	(2,055)	(3,398)	(116)	(195)
Fair value of plan assets at end of year	25,465	29,416		
Funded status at end of year	(13,657)	$ (14,433)	(19,280)	$ (15,004)
Unrecognized net actuarial loss[(b)]	6,780	N/A	5,366	N/A
Unrecognized prior service cost[(b)]	5,487	N/A	7,313	N/A
Accrued benefit cost	$ (1,390)	N/A	$ (6,601)	N/A
Accumulated affiliate benefit obligation	$ 28,629	$ 32,042	N/A	N/A

(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 medical and life benefit plan.

(b) Prior to the adoption in 2006 of SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*, these amounts were not recognized as liabilities in our consolidated balance sheets as prescribed under SFAS No. 87, *Employers Accounting for Pensions* and SFAS No. 106, *Employers Accounting for Postretirement Benefits Other Than Pensions*.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The amounts included in pension benefits in the above table combine the union pension plan with the non-union pension plan. At December 31, 2005 the accumulated benefit obligations of both plans exceeded the fair value of their respective plan assets. At December 31, 2006, the union pension plan had an accumulated benefit obligation of $23.2 million, which exceeded the fair value of plan assets of $20.4 million. Amounts recognized in our consolidated balance sheets were as follows (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2005	2006	2005	2006
Amounts recognized in the consolidated balance sheet:				
Current accrued benefit cost	$	$	$	$ (159)
Long-term accrued benefit cost	(3,165)	(14,433)	(6,601)	(14,845)
Intangible assets	1,432			
	(1,733)	(14,433)	(6,601)	(15,004)
Accumulated other comprehensive income:				
Net loss	343	6,390	N/A	5,411
Prior service cost		4,809	N/A	977
Net amount recognized in consolidated balance sheet	$ (1,390)	$ (3,234)	$ (6,601)	$ (8,616)

Net pension and other postretirement benefit expense for the years ended December 31, 2004, 2005 and 2006 consisted of the following (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2004	2005	2006	2004	2005	2006
Components of net periodic pension and postretirement benefit expense:						
Service cost	$ 3,647	$ 4,215	$ 5,587	$ 324	$ 530	$ 469
Interest cost	1,707	1,866	2,206	682	994	834
Expected return on plan assets	(1,637)	(1,918)	(1,906)			
Amortization of prior service cost	677	677	678	1,798	1,798	177
Amortization of actuarial loss		25	538		575	675
Net periodic expense	$ 4,394	$ 4,865	$ 7,103	$ 2,804	$ 3,897	$ 2,155

Additionally, expenses related to the defined contribution plan were $3.1 million, $3.8 million and $4.1 million, in 2004, 2005 and 2006, 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 2007 are $0.2 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 2007 are $0.4 million and $0.2 million, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The effect of SFAS No. 158 on amounts reported in our consolidated balance sheet as of December 31, 2006 was as follows (in thousands):

	Before Application of SFAS No. 158	SFAS No. 158 Adjustments	As Reported
Affiliate payroll and benefits	$ 18,517	$ 159	$ 18,676
Total current liabilities	518,230	159	518,389
Long-term affiliate pension and benefits	11,850	17,428	29,278
Accumulated other comprehensive loss	(1,264)	(17,587)	(18,851)
Total partners capital	824,069	(17,587)	806,482

The weighted-average rate assumptions used to determine benefit obligations as of December 31, 2005 and 2006 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2005	2006	2005	2006
Discount rate	5.50%	5.75%	5.50%	6.00%
Rate of compensation increase non-union plan	5.00%	5.00%	N/A	N/A
Rate of compensation increase union plan	5.00%	4.50%	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, 2004, 2005 and 2006 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2004	2005	2006	2004	2005	2006
Discount rate	6.25%	5.75%	5.50%	6.25%	5.75%	5.50%
Expected rate of return on plan assets	8.50%	8.50%				