MAGELLAN MIDSTREAM PARTNERS LP
Form 10-K
February 25, 2011
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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, 2010
OR

o	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 (State or other jurisdiction of incorporation or organization)	73-1599053 (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 o
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 o
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 o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company.

Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller reporting company o
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No x
The aggregate market value of the registrant's voting and non-voting limited partner units held by non-affiliates computed by reference to the price at which the limited partner units were last sold as of June 30, 2010 was $4,972,148,283.
As of February 24, 2011, there were 112,736,571 limited partner units outstanding.
DOCUMENTS INCORPORATED BY REFERENCE
Portions of the registrant's Proxy Statement being prepared for the solicitation of proxies in connection with the 2011 Annual Meeting of Limited Partners are to be incorporated by reference in Part III of this Form 10-K.

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MAGELLAN MIDSTREAM PARTNERS, L.P.
FORM 10-K
PART I
Item 1. Business
(a) General Development of Business

We are a Delaware limited partnership formed in August 2000 and our limited partner units are traded on the New York Stock Exchange under the ticker symbol “MMP.” Magellan GP, LLC (“MMP GP”), a wholly-owned Delaware limited liability company, serves as our general partner. Unless indicated otherwise, the terms “our,” “we,” “us” and similar language refer to Magellan Midstream Partners, L.P. together with its subsidiaries.

Business Acquisition

In September 2010, we acquired an aggregate 7.8 million barrels of crude oil storage in the Cushing, Oklahoma area and more than 100 miles of active petroleum pipelines in the Houston, Texas area from BP Pipelines (North America), Inc. ("BP") for $291.3 million. Additionally, related to this transaction, during October 2010, we acquired certain crude oil working inventory at a fair value of approximately $53.0 million. These assets have improved our connectivity with existing markets as well as expanded our crude oil logistics infrastructure. We have leased a majority of the crude oil storage included in this acquisition to BP for an intermediate period.
(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 and crude oil. As of December 31, 2010, our asset portfolio consists of:

- petroleum pipeline system, comprised of approximately 9,600 miles of pipeline and 51 terminals;

- petroleum terminals, which includes storage terminal facilities (consisting of six marine terminals located along coastal waterways and crude oil storage in Cushing, Oklahoma) and 27 inland terminals; and

- ammonia pipeline system, representing our 1,100-mile ammonia pipeline and six associated terminals.

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

The Gulf Coast region is a significant supply source for our facilities and is a major hub for petroleum refining. According to the “Annual Refinery Report for 2010” published by the Energy Information Administration (“EIA”), the Gulf Coast region accounted for approximately 45% of total U.S. daily refining capacity and 76% of U.S. refining capacity expansion from 1999 to 2010. The growth in Gulf Coast refining capacity has resulted in part from consolidation in the petroleum industry to take advantage of economies of scale from operating larger refineries.

Crude Oil Logistics Industry Background

The crude oil slate available to U.S. and world-wide refineries consists of a substantial number of different grades and varieties of crude oil. This is due to crude oil grades produced from different producing regions, whether from within or outside the United States, that may have unique qualities, each with varying economic attributes. Consequently, different refineries have developed a distinct configuration of process units designed to handle particular grades of crude oil. This creates transportation, terminalling and storage challenges associated with regional volumetric supply and demand imbalances. In many cases, these factors result in the need for such grades to be batched or segregated in the transportation and storage

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processes or blended to precise specifications. One of the largest storage hubs for crude oil is in Cushing, Oklahoma, the delivery point for crude oil futures contracts traded on the New York Mercantile Exchange ("NYMEX"). From Cushing the crude oil is shipped to various refineries.

Petroleum Products Logistics

Petroleum products transported, stored and distributed through our petroleum pipeline system and petroleum terminals include:

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

- liquefied petroleum gases, or LPGs, which are produced as by-products of the crude oil refining process and in connection with natural gas production. LPGs include butane and propane;

- blendstocks, which are blended with petroleum products to change or enhance their characteristics such as increasing a gasoline's octane or oxygen content. Blendstocks include alkylates and oxygenates;

- heavy oils and feedstocks, which are used as burner fuels or feedstocks for further processing by refineries and petrochemical facilities. Heavy oils and feedstocks include No. 6 fuel oil and vacuum gas oil; and

- crude oil and condensate, which are used as feedstocks by refineries. In addition, we store, blend and distribute biofuels such as ethanol and biodiesel, which are increasingly required by government mandates.

Description of Our Businesses

PETROLEUM PIPELINE SYSTEM

Our common carrier petroleum pipeline system extends approximately 9,600 miles and covers a 13-state area, extending from the Gulf Coast refining region across Texas and through the Midwest to Colorado, North Dakota, Minnesota, Wisconsin and Illinois. Our pipeline system transports petroleum products and includes 51 terminals. The products transported on our pipeline system are largely transportation fuels and, in 2010, were comprised of 54% gasoline, 34% distillates (which include diesel fuels and heating oil), 8% aviation fuel and LPGs and 4% crude oil. Refined product and LPG shipments originate on our pipeline system from direct connections to refineries and interconnections with other interstate pipelines for transportation and ultimate distribution to retail gasoline stations, truck stops, railroads, airports and other end-users. Crude oil shipments originate on our pipeline system from connections to crude oil terminals as well as interconnections with other pipelines for transportation and distribution to refineries.

Our petroleum pipeline system segment accounted for the following percentages of our consolidated revenues, operating margin and total assets:

	Year Ended December 31,					
	2008		2009		2010	
Percent of consolidated revenues	84	%	80	%	85	%
Percent of consolidated operating margin	79	%	75	%	79	%
Percent of consolidated total assets	68	%	73	%	70	%

See Note 16—Segment Disclosures in the accompanying consolidated financial statements for additional financial information about our petroleum pipeline system segment.

The portion of our petroleum pipeline system that ships refined products and LPGs is dependent on the ability of refiners and marketers to meet the demand for those products in the markets they serve through their shipments on our pipeline system. According to December 2010 projections provided by the EIA, the demand for refined petroleum products in the primary market areas served by our petroleum pipeline system, known as West North Central and West South Central census districts, is expected to remain relatively stable over the next 10 years. The total production of refined petroleum products from refineries located in West North Central districts has historically been insufficient to meet the demand for refined petroleum products. Any excess West North Central demand has been and is expected to be met largely by imports of refined petroleum products

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via pipelines from Gulf Coast refineries that are located in the West South Central census region.
Our petroleum pipeline system is well-connected to Gulf Coast refineries. In addition to our own pipeline that originates in the Gulf Coast region, we also have interconnections with third-party pipelines that originate on the Gulf Coast. These connections to Gulf Coast refineries, together with our pipeline’s extensive network throughout the West North Central district should aid us in accommodating any demand growth or supply shifts that may occur.
The portion of our petroleum pipeline system that ships crude oil is dependent upon the production levels and related crude oil demand by Texas City, Texas refineries, predominantly BP's Texas City, Texas refinery. Additional connections for this pipeline are being evaluated that will provide access to a broader group of refineries in the Houston refining region.
The operating statistics below reflect our petroleum pipeline system’s operations for the periods indicated:

	Year Ended December 31,		
	2008	2009	2010
Shipments (thousand barrels):			
Refined products			
Gasoline	152,703	169,873	194,338
Distillates	114,751	100,214	122,929
Aviation fuel	22,190	19,843	22,612
LPGs	6,252	5,770	4,949
Crude oil	—	—	14,658
Total product shipments	295,896	295,700	359,486
Capacity leases	24,665	29,821	27,084
Total shipments, including capacity leases	320,561	325,521	386,570
Daily average (thousand barrels)	876	892	1,059

The maximum number of barrels our petroleum 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 pipeline system, if necessary.

Operations. Our petroleum pipeline system is the longest common carrier pipeline for refined petroleum products and LPGs in the United States. Through direct refinery connections and interconnections with other interstate pipelines, our system can access more than 44% of the refinery capacity in the continental United States. Most of the shipments on our pipeline system are for third parties and we do not take title to those products. We do take title to products related to our petroleum products blending and fractionation activities, the linefill related to the Houston-to-El Paso pipeline section we acquired in 2009 and petroleum products we transport on this pipeline section for sale in El Paso, Texas. Furthermore, under our tariffs, we are allowed to deduct from our shipper's inventory a prescribed quantity of the products our shippers transport on our pipeline to compensate us for metering inaccuracies, evaporation or other events that result in volume losses in the shipment process. To the extent we can manage our volume loss below the deducted amount, we take title to those products which we can sell, thereby reducing our operating expenses.

In 2010, our petroleum pipeline system generated 72% of its revenue, excluding product sales revenues, from transportation tariffs on volumes shipped. These transportation tariffs vary depending upon where the product originates, where ultimate delivery occurs and any applicable discounts. All interstate transportation rates and discounts are in published tariffs filed with the Federal Energy Regulatory Commission (“FERC”). Included as part of these tariffs are charges for terminalling and storage of products at 35 of our pipeline system's 51 terminals. Revenues from terminalling and storage at our other 16 terminals are at privately negotiated rates.

In 2010, our petroleum pipeline system generated the remaining 28% of its revenues, excluding product sales revenues, from leasing pipeline and storage tank capacity to shippers and from providing product and other services such as ethanol and biodiesel unloading and loading, additive injection, custom blending, laboratory testing and data services to shippers, which are performed under a mix of “as needed,” monthly and long-term agreements. We also receive a fee for operating a 135-mile pipeline (in which we have a 50% interest) that transports crude oil from Cushing, Oklahoma to El Dorado, Kansas and has

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connections to National Cooperative Refining Association's refinery in McPherson, Kansas and Frontier Oil Corporation's refinery in El Dorado, Kansas.

Product revenues for the petroleum pipeline system primarily results from our petroleum products blending and transmix fractionation activities and from linefill management and product marketing associated with our Houston-to-El Paso pipeline section. Our petroleum products blending activity involves purchasing LPGs and blending them into gasoline, which creates additional gasoline available for us to sell. This activity is limited by seasonal gasoline vapor pressure specifications and by the varying quality of the product delivered to us at our pipeline origins. We typically lock in most of the margin from this blending activity by entering into either forward physical or NYMEX gasoline futures contracts at the time we purchase the related LPGs. We also operate two fractionators along our pipeline system that separate transmix, which is an unusable mixture of various petroleum products, back into its original components. We purchase transmix from third parties and sell the resulting separated petroleum products. We also purchase petroleum products for shipment on the Houston-to-El Paso pipeline section to facilitate product shipments on the pipeline. We sell these products in the El Paso, Texas wholesale markets. Product margin from all of these activities was $114.4 million, $44.2 million and $81.3 million for the years ended December 31, 2008, 2009 and 2010, respectively. The amount of margin we earn from these activities fluctuates with changes in petroleum prices. Product margin is not a generally accepted accounting principle financial measure but its components are determined in accordance with generally accepted accounting principles. Product margin, which is calculated as product sales revenues less product purchases, is used by management to evaluate the profitability of our commodity-related activities.

Commodity Risk Management

Our blending, fractionation and pipeline linefill management activities require us to carry significant levels of inventories. As the volume of petroleum products sales has increased, risk management strategies have become increasingly important in creating and maintaining margins. We use derivative instruments to hedge margins involving our physical assets and manage risks associated with our various commodity purchase and sale obligations. Our risk management policies and procedures are designed to monitor our derivative instrument positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity to help ensure that our hedging activities address our risks. Our risk management function has direct responsibility and authority for our risk policies, related controls around commercial activities and procedures and certain other aspects of corporate risk management. Our approved strategies are primarily intended to mitigate and manage price risks that are inherent in our blending, fractionation and pipeline linefill activities. However, not all of our hedges will qualify for hedge accounting treatment given that these contracts are for commodities delivered in the New York harbor, while our physical commodity transactions are generally conducted in the Gulf Coast or mid continent markets in the United States.

Our policy is generally to purchase only those products necessary to conduct our normal business activities. We do not acquire and hold physical inventory, futures contracts or other derivative instruments for the purpose of speculating on commodity price changes as these activities could expose us to significant losses.

Facilities. Our petroleum pipeline system consists of an approximate 9,600-mile pipeline and 51 terminals and includes more than 37 million barrels of aggregate usable storage capacity. The terminals on our pipeline system deliver petroleum products primarily into tank trucks.

Petroleum Products Supply. Petroleum products originate from refineries, pipeline interconnection points and terminals along our pipeline system. In 2010, approximately 64% of the petroleum products transported on our petroleum pipeline system originated from 13 direct refinery connections and 36% originated from interconnections with other pipelines or terminals.

The portion of our system that transports refined petroleum products and LPGs is directly connected to and receives product from 13 refineries shown below:

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Major Origins—Refineries (Listed Alphabetically)

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

Our system is also connected to multiple pipelines and terminals, including those shown in the table below:

Major Origins—Pipeline and Terminal Connections (Listed Alphabetically)

Pipeline/Terminal	Connection Location	Source of Product
Refined Products:		
BP	Manhattan, IL	Whiting, IN refinery
Cenex	Fargo, ND	Laurel, MT refinery
Conoco Phillips	Kansas City, KS	Various Gulf Coast refineries (via Seaway/Standish Pipeline); Borger, TX refinery
Explorer	Glenpool, OK; Mt. Vernon, MO; Dallas, TX; East Houston, TX; Mt. Pleasant, TX	Various Gulf Coast refineries
Kinder Morgan	Galena Park and Pasadena, TX	Various Gulf Coast refineries and imports
Magellan Terminals Holdings	Galena Park, TX	Various Gulf Coast refineries and imports
Mid-America (Enterprise)	El Dorado, KS	Conway, KS storage
NuStar Energy	El Dorado, KS; Minneapolis, MN	Various OK & KS refineries and Mandan, ND refinery
ONEOK Partners	Plattsburg, MO; Des Moines, IA; Wayne, IL	Bushton, KS storage and Chicago, IL area refineries
Sinco	East Houston, TX	Deer Park, TX refinery
West Shore	Chicago, IL	Various Chicago, IL area refineries
Crude:		
Speed Junction	Houston, TX	Various Houston, TX terminals and two pipelines along the Houston ship channel
Genoa Junction	Houston, TX	Two pipelines near the Houston ship channel

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 refined product deliveries are primarily retail gasoline stations, truck stops, farm cooperatives, railroad fueling depots and military and commercial jet fuel users. LPG shippers include wholesalers and retailers who, in turn, sell to commercial, industrial, agricultural and residential heating customers, as well as utilities who use propane as a fuel source. Crude shippers are predominately refiners who ship crude oil for their own refinery needs. Published tariffs serve as contracts and shippers nominate the volume to be shipped up to a month in advance. In addition, we enter into supplemental agreements with shippers that commonly result in volume and/or term commitments by shippers in exchange for reduced tariff rates or capital expansion commitments on our part. For 2010, approximately 54% of the shipments on our pipeline system were subject to these supplemental agreements . While many of these agreements do not represent guaranteed volumes, they do reflect a significant

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level of shipper commitment to our petroleum pipeline system.

For the year ended December 31, 2010, our petroleum pipeline system had approximately 60 transportation customers. The top 10 shippers included independent refining companies, integrated oil companies and farm cooperatives. Revenues attributable to these top 10 shippers for the year ended December 31, 2010 represented 42% of total revenues for our petroleum pipeline system and 59% of revenues excluding product sales.

Our product sales have historically been primarily to trading and marketing companies. These sales agreements are generally short-term in nature.

Markets and Competition. In certain markets, barge, truck or rail provide an alternative source for transporting petroleum 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 agrees to supply a market near its refinery or terminal in exchange for receiving supply from another refinery or terminal in a more distant market. These agreements allow the two parties to reduce the volumes transported and the average transportation rate paid to us. We have been able to compete with these alternatives through price incentives and through long-term commercial arrangements with potential exchange partners. Nevertheless, a significant amount of exchange activity has occurred historically and is likely to continue.

Government mandates increasingly require the use of renewable fuels, particularly ethanol. Ethanol producers are responding to these mandates by significantly increasing their capacity for production of ethanol. Due to concerns regarding corrosion and product contamination, pipelines have generally not shipped ethanol and most ethanol is transported by railroad or truck. The increased use of ethanol has and will continue to compete with shipments on our pipeline systems. However, most terminals on our pipeline system have the necessary infrastructure to blend ethanol with refined products. We earn revenues for these services that to date have been more than sufficient to offset any reduction in transportation revenues due to ethanol blending.

PETROLEUM TERMINALS

We operate two types of terminals: storage terminals and inland terminals. Our storage terminals are large storage and distribution facilities that in many cases have marine access and in some cases are in close proximity to large refining complexes. Our crude storage terminal is located in Cushing, Oklahoma, one of the largest crude oil trading hubs in the United States. Our inland terminals are primarily located in the southeastern United States along third-party pipelines such as those operated by Colonial, Explorer, Plantation and TEPPCO. Our facilities receive products from pipelines and distribute them to third parties at the terminals, which in turn deliver them to end-users such as retail outlets. Because these terminals are unregulated, the marketplace determines the prices we can charge for our services. In general, we do not take title to the products that are stored in or distributed from our terminals. Our petroleum terminals segment accounted for the following percentages of our consolidated revenues, operating margin and total assets:

	Year Ended December 31,					
	2008		2009		2010	
Percent of consolidated revenues	14	%	18	%	14	%

Percent of consolidated operating margin	19 %	23 %	22 %
Percent of consolidated total assets	28 %	25 %	28 %

See Note 16—Segment Disclosures in the accompanying consolidated financial statements for additional financial information about our petroleum terminals segment.

Storage Terminals

We own and operate six storage terminals located along coastal waterways and a crude oil storage terminal in Cushing, Oklahoma. Our storage terminals have an aggregate storage capacity of approximately 31 million barrels and provide distribution, storage, blending, inventory management and additive injection services for refiners and other large end-users of petroleum products. Our crude oil terminal has an aggregate storage capacity of approximately 8 million barrels.

Our Cushing terminal primarily receives and distributes crude oil via common carrier pipelines and short-haul pipeline connections with neighboring crude oil terminals. Our other storage 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 these storage terminals by all of those means as well as by truck and rail. Products that we store include refined petroleum products, blendstocks, crude oils, heavy oils and feedstocks. In addition to providing storage and distribution services, our storage terminals provide ancillary services including heating, blending and mixing of stored products and additive injection services.

Our storage terminals generate revenues primarily through providing long-term storage services for a variety of customers. Refiners and chemical companies typically use our storage terminals because their facilities are inadequate, either because of size constraints or the specialized handling requirements of the stored product. We also provide storage services to marketers and traders that require access to large storage capacity.

Customers and Contracts. We have long-standing relationships with oil refiners, suppliers and traders at our facilities. During 2010, approximately 97% of our storage terminal capacity was utilized. As of December 31, 2010, approximately 95% of our usable storage capacity was under long-term contracts with remaining terms in excess of one year or that renew on an annual basis. These contracts obligate the customer to pay for terminal capacity reserved even if not used by the customer.

Markets and Competition. We believe that the continued strong demand for our storage terminals results from our cost-effective distribution services and key transportation links, which provide us with a stable base of storage fee revenues. The additional heating and blending services we provide at our storage terminals attract additional demand for our storage services and result in increased revenue opportunities. Demand can also be influenced by projected changes in and volatility of petroleum product prices.

Several major and integrated oil companies have their own proprietary storage terminals that are or have been used in their refining operations. If these companies choose to shut down their refining operations and elect to store and distribute petroleum products through their proprietary terminals, we could experience increased competition for the services we provide. In addition, other companies have facilities that offer competing storage and distribution services and a significant amount of additional competing storage capacity has been constructed recently.

Inland Terminals

We own and operate a network of 27 refined petroleum products terminals located primarily in the southeastern United States. We wholly own 25 of the 27 terminals in our portfolio. Our terminals have a combined capacity of more than 5 million barrels. Our customers utilize these facilities to take delivery of refined petroleum products transported on major common carrier interstate pipelines. The majority of our inland terminals connect to the Colonial, Explorer, Plantation or TEPPCO pipelines, and some facilities have multiple pipeline connections. We load and unload products through an automated system that allows products to move from the common carrier pipelines to our storage tanks and from our storage tanks to a truck or railcar loading rack. During 2010, gasoline represented approximately 66% of the product volume distributed through our inland terminals, with the remaining 34%

consisting of distillates.

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

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

Customers and Contracts. We enter into contracts with customers that typically last for one year with a provision that, at the end of each contract's term, automatically renews the contract for another one-year period unless we or our customer provide written notice to cancel the contract. A number of these contracts contain a minimum throughput provision that obligate

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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, other independent terminal operators and refining and marketing companies.

AMMONIA PIPELINE SYSTEM

We own an 1,100-mile common carrier ammonia pipeline system. Our pipeline system transports ammonia from production facilities in Texas and Oklahoma to terminals in the Midwest. The ammonia we transport is primarily used as a nitrogen fertilizer. The ammonia pipeline system segment accounted for the following percentages of our consolidated revenues, operating margin and total assets:

	Year Ended December 31,		
	2008	2009	2010
Percent of consolidated revenues	2 %	2 %	1 %
Percent of consolidated operating margin	2 %	1 %	(1)%
Percent of consolidated total assets	1 %	1 %	1 %

See Note 16–Segment Disclosures in the accompanying consolidated financial statements for additional financial information about the ammonia pipeline system segment.

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

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

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 rolling three-year transportation agreements with our three customers. Each transportation agreement contains a ship-or-pay provision whereby each customer committed a tonnage that it expects to ship. If a customer fails to ship its annual commitment, that customer must pay for the unused pipeline capacity. Aggregate annual commitments from our customers for the period July 1, 2010 through June 30, 2011 are 550,000 tons.

Markets and Competition. Demand for nitrogen fertilizer typically follows a combination of weather patterns, 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 during periods of high natural gas prices.

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

GENERAL BUSINESS INFORMATION

Major Customers

The percentage of revenue derived by customers that accounted for 10% or more of consolidated total revenues is provided in the table below. No other customer accounted for more than 10% of our consolidated total revenues for 2008, 2009

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or 2010. The majority of the revenues from Customers A and B resulted from sales to those customers of refined petroleum products that were generated in connection with our petroleum products blending and fractionation activities, which is included in our petroleum pipeline system segment. In general, accounts receivable from these customers are due within 3 days of sale. If these customers were unable to purchase petroleum products from us, we believe that other companies would purchase the products from us.

	Year Ended December 31,		
	2008	2009	2010
Customer A	12 %	5 %	13 %
Customer B	12 %	11 %	11 %
Total	24 %	16 %	24 %

Tariff Regulation

Interstate Regulation. Our petroleum 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, including rates for all petroleum products, 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 pipeline system, are currently regulated by FERC primarily through an index methodology, which for the five-year period ending July 2010, was set at the change in the producer price index for finished goods (“PPI-FG”) plus 1.3%. In December 2010, the FERC established a new price index of PPI-FG plus 2.65% for the five-year period beginning July 1, 2011. Certain shippers have requested a rehearing of this matter by the FERC and other shippers have asked a U.S. court of appeals to review FERC's decision. At this time, management is unable to determine whether the FERC will rehear this matter or whether the court of appeals will review it or what outcome might result should such rehearing or court review occur.

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 pipeline system is subject to this indexing methodology. In addition to rate indexing and cost-of-service filings, interstate oil pipeline companies may elect to support rate filings by obtaining authority to charge market-based rates, by settlement with respect to existing rates or through an agreement with an unaffiliated person who intends to use the related service. Approximately 60% of our petroleum pipeline system's markets are deemed competitive by the FERC and we are allowed to charge market-based rates in these markets.

In May 2005, the FERC adopted a policy statement indicating it would permit entities owning public utility assets, including oil pipelines, to include an income tax allowance in such utilities' cost-of-service rates to reflect actual or potential tax liability attributable to their public utility income, regardless of the form of ownership. Pursuant to this policy statement, a tax pass-through entity seeking such an income tax allowance would have to establish that its partners or members have an actual or potential income tax obligation on the entity's public utility income. This tax allowance policy was upheld by the D.C. Circuit in May 2007. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although this policy is generally favorable for pipelines that are organized as pass-through entities such as a partnership, it still entails rate risk due to the case-by-case review requirement.

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

Intrastate Regulation. Some shipments on our petroleum pipeline system move within a single state and thus are considered to be intrastate commerce. Our petroleum 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

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pipelines.

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

Market Manipulation Regulations

Wholesale sales of petroleum are subject to provisions of the Energy Independence and Security Act of 2007 (“EISA”) and regulations by the Federal Trade Commission (“FTC”) with respect to trading and market manipulation. The Commodity Futures Trading Commission (the “CFTC”) has similar authority over commodities trading and futures contracts pursuant to the Commodity Exchange Act. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation. In addition, our rates for interstate pipeline transportation services are regulated by the FERC under the Interstate Commerce Act (“ICA”). Should we violate anti-manipulation laws and regulations or the ICA and FERC's regulations under the ICA, we could also be subject to disgorgement of profits or the payment of refunds and to recommended criminal penalties. Should we violate these laws and regulations, we could also be subject to related third-party damage claims.

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

Environmental, Maintenance, Safety & Security

General. The operation of our pipeline systems, terminals and associated facilities is subject to strict and complex laws and regulations relating to the protection of the environment and providing an employment workplace that is free from recognized hazards. These bodies of laws and regulations govern many aspects of our business including the work environment, the generation and disposal of waste, discharge of process and storm water, air emissions, remediation requirements as well as facility design requirements to protect against releases into the environment. We believe our assets are operated and maintained in material compliance with these laws and regulations and in accordance with other generally accepted industry standards and practices.

Environmental. Estimates for remediation costs assume that we will be able to use traditionally acceptable remedial and monitoring methods, as well as associated engineering or institutional controls to comply with applicable regulatory requirements. These estimates include the cost of performing environmental assessments, remediation and monitoring of the impacted environment such as soils, groundwater and surface water conditions. Remediation costs are estimates and total remediation costs may exceed current estimated amounts.

We may experience future releases of regulated materials into the environment or discover historical releases that were previously unidentified or not assessed. While an asset integrity and maintenance program designed to prevent, promptly detect and address releases is an integral part of our operations, damages and liabilities arising out of any environmental release from our assets identified in the future have the potential to have a material adverse effect on our results of operations, financial position and cash flow.

Environmental Liabilities. Liabilities recognized for estimated environmental costs were $34.4 million and $32.8 million at December 31, 2009 and December 31, 2010, respectively. Environmental liabilities have been classified as current or noncurrent based on management's estimates regarding the timing of actual payments. Management estimates that expenditures associated with these environmental liabilities will be paid over the next ten years.

Environmental Receivables. Receivables from insurance carriers related to environmental matters were $3.9 million and $2.2 million at December 31, 2009 and December 31, 2010, respectively.

Environmental Insurance Policies. We have insurance policies which provide coverage for environmental matters associated with liabilities arising from sudden and accidental releases of products applicable to all of our assets. We have pollution legal liability insurance policies to cover pre-existing unknown conditions on the majority of our petroleum pipeline system that have various terms, with most expiring between 2014 and 2017.

Clean Air Act. Our operations are subject to the federal Clean Air Act ("CAA"), as amended, and comparable state and

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local laws. The CAA requires sources of emissions to obtain construction permits or approvals for new construction and operating permits for existing operations. We believe that we currently hold or have applied for all necessary air permits.

Petroleum Products Blending Review. As a result of an internal operational review of our petroleum products blending activity, we have disclosed instances of regulatory non-compliance to the Environmental Protection Agency ("EPA"). We have not received a response from the EPA on this matter and management believes that this situation will not result in the imposition of material fines or penalties on us by the EPA.

Department of Homeland Security Appropriation Act of 2007. This act requires the Department of Homeland Security ("DHS") to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present "high levels of security risk." The DHS has issued rules that establish chemicals of interest and their respective threshold quantities that will trigger compliance with these standards. The owners of facilities covered by these DHS rules that are determined by the DHS to pose a higher level of security risk will be required to prepare and submit Security Vulnerability Assessments and Site Security Plans as well as comply with other regulatory requirements, including those regarding inspections, audits, recordkeeping and protection of chemical-terrorism vulnerability information.

DHS has determined that one of our facilities storing butane met their security risk screening threshold and is regulated under DHS's Chemical Facility Anti-Terrorism Standards ("CFATS"). We have submitted a security plan for this facility and are awaiting a response from the DHS as to whether additional security measures will be needed for this facility to be in compliance with CFATS. With regard to gasoline storage facilities, the DHS has decided to delay final security risk determinations and issued a notice in the Federal Register asking for comments on including gasoline as a chemical of interest under CFATS. Management believes that our costs to comply with CFATS will not be material to our operating results, financial position or cash flows.

Hazardous Substances and Wastes. In most instances, the environmental laws and regulations affecting our operations relate to the release of hazardous substances or solid wastes into water or soils, and include measures to control pollution of the environment. For instance, the Comprehensive Environmental Response, Compensation and Liability Act, also known as the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment.

Our operations also generate wastes, including hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. We are not currently required to comply with a substantial portion of the RCRA requirements because our operations routinely generate only small quantities of hazardous wastes, and we are not a hazardous waste treatment, storage or disposal facility operator that is required to obtain a RCRA hazardous waste permit. While RCRA currently exempts a number of wastes from being subject to hazardous waste requirements, including many oil and gas exploration and production wastes, the EPA can consider the adoption of stricter disposal standards for non-hazardous wastes. Moreover, it is possible that additional wastes, which could include non-hazardous wastes currently generated during operations, may be designated as hazardous wastes. Hazardous wastes are subject to more rigorous and costly storage and disposal requirements than non-hazardous wastes. Changes in the regulations could materially increase our expenses.

We own or lease properties where hydrocarbons are being or have been handled for many years. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on, under or from the properties owned or leased by us or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties were previously operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and wastes disposed thereon may be subject to the Superfund law, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed of or released by prior owners or operators, to remediate contaminated property, including groundwater contaminated by prior owners or operators, or to make capital improvements to prevent future contamination.

As part of our assessment of facility operations, we have identified some above ground tanks at our terminals that either are, or are suspected of being, coated with lead-based paints. The removal and disposal of any paints that are found to be lead-based, whenever such activities are conducted in the future as part of our day-to-day maintenance activities, will require increased handling. However, we do not expect the costs associated with this increased handling to be significant.

Water Discharges. Our operations can result in the discharge of pollutants, including oil and petroleum products. The Oil Pollution Act amended provisions of the Federal Water Pollution Control Act of 1972 (“Water Pollution Control Act”) and other statutes as they pertain to prevention and response to oil and refined product spills. The Oil Pollution Act subjects owners of facilities to strict, joint and potentially significant liability for removal costs and certain other consequences of an oil spill such as natural resource damages, where the product spills into navigable waters, along shorelines or in the exclusive economic zone of the United States. In the event of an oil spill from one of our facilities into navigable waters, substantial liabilities could be imposed. States in which we operate have also enacted similar laws. The Water Pollution Control Act imposes restrictions and strict controls regarding the discharge of pollutants into navigable waters. This law and comparable state laws require that permits be obtained to discharge pollutants into state and federal waters and impose substantial potential liability for the costs of non-compliance and damages. Where required, we hold discharge permits that were issued under the Water Pollution Control Act or a state-delegated program. While we have occasionally exceeded permit discharges at some of our terminals, we do not expect our non-compliance with existing permits to have a material adverse effect on our results of operations, financial position or cash flows.

Greenhouse Gas Emissions. In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. Consequently, the EPA proposed two sets of regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and, also, could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010.

Further, Congress has actively considered various proposals to reduce greenhouse gas emissions that may impose a carbon emissions tax, a cap-and-trade program or other programs aimed at carbon reduction, including the American Clean Energy and Security Act of 2009, passed by the U.S. House of Representatives in June 2009 and a similar bill in the U.S. Senate. Either bill would have established an economy-wide cap-and-trade program to reduce United States emissions of greenhouse gases including carbon dioxide and methane that may contribute to the warming of the earth's atmosphere and other climatic changes. Future laws might require reduction in greenhouse gas emissions by 2020 with a further reduction of such emissions by 2050. Allowances under a future cap-and-trade program would be expected to significantly escalate in cost over time. The net effect of such potential legislature would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products and natural gas. President Obama has indicated his support of legislation to reduce greenhouse gas emissions through an emission allowance system. In addition, at least one-third of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap-and-trade programs. Our compliance with any future legislation or regulation of greenhouse gases, if it occurs, may result in increased compliance and operating costs. It is not possible at this time to predict with any accuracy the structure or outcome of any future legislative or regulatory efforts to address such emissions or the eventual costs to us of compliance.

Maintenance. Our pipeline systems are subject to regulation by the United States Department of Transportation under the Hazardous Liquid Pipeline Safety Act ("HLPSA") of 1979, as amended, and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. HLPSA covers petroleum, petroleum products and anhydrous ammonia and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to make certain reports and provide information as required by the Department of Transportation. Our assets are also subject to various federal security regulations, and we believe we are in substantial compliance with all applicable regulations.

The Department of Transportation requires operators of hazardous liquid interstate pipelines to develop and follow an integrity management program that provides for assessment of the integrity of all pipeline segments that could affect designated “high consequence areas,” including high population areas, drinking water, commercially navigable waterways and ecologically sensitive resource areas. Segments of our pipeline systems have the potential to impact high consequence areas.

Our marine terminals along coastal waterways are subject to United States Coast Guard regulations and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of these assets.

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

Changes to federal pipeline safety laws and regulations are being considered by Congress and the Pipeline Hazardous Materials Safety Administration ("PHMSA") of the U.S. Department of Transportation ("DOT"). Legislation requiring more stringent regulation was passed by the U.S. House of Representatives in 2010 but was not put to a vote in the U.S. Senate. Similar legislation is expected to be considered in the current session of Congress. The DOT has proposed legislation providing for more stringent oversight of pipelines and increased penalties. PHMSA has also announced an intention to strengthen its rules and regulations. Such legislative and regulatory changes could have a material effect on our operations and costs of transportation service due to more stringent and comprehensive safety regulation and higher penalties for violations of those regulations.

Title to Properties

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

Some of the leases, easements, rights-of-way, permits and licenses that have been transferred to us are only transferable with the consent of the grantor of these rights, which in some instances is a governmental entity. We believe that we have obtained or will obtain sufficient third-party consents, permits and authorizations for the transfer of the assets necessary for us to operate our business in all material respects. We believe that a failure to obtain all consents, permits or authorizations will not have a material adverse effect on the operation of our business.

We believe that we have satisfactory title to all of our assets or are entitled to indemnification from former affiliates for title defects to our ammonia pipeline that arise before February 2016 and title defects related to the portion of our petroleum 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 the acquisition of real property, liens that can be imposed in some jurisdictions for government-initiated action to clean up environmental contamination, liens for current taxes and other burdens, and easements, restrictions and other encumbrances to which the underlying properties were subject at the time of acquisition by us or our predecessor, we believe that none of these burdens should materially detract from the value of our properties or from our interest in them or should materially interfere with their use in the operation of our business.

Employees

As of December 31, 2010, we had 1,271 employees. At December 31, 2010, the labor force of 542 employees assigned to our petroleum pipeline system was concentrated in the central United States. Approximately 39% of these employees were represented by the United Steel Workers Union ("USW"). Our collective bargaining agreement with the USW expires January 31, 2012. The labor force of 284 employees assigned to our petroleum terminals operations at December 31, 2010 was primarily concentrated in the southeastern and Gulf Coast regions of the United States. Approximately 9% of these employees were represented by the International Union of Operating Engineers ("IUOE") and covered by a collective bargaining agreement that expires in October 2013. At December 31, 2010, the labor force of 20 employees assigned to our ammonia pipeline system was concentrated in the central United States. None of these employees was covered by a collective bargaining agreement.

(d) Financial Information About Geographical Areas

We have no international activities. For all periods included in this report, all our revenues were derived from operations conducted in, and all of our assets were located in, the United States. See Note 16–Segment Disclosures in the notes to consolidated financial statements for information regarding our revenues and total assets.

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(e) Available Information

We file annual, quarterly and current reports, proxy statements and other information electronically with the Securities and Exchange Commission ("SEC"). You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC, including our filings.

Our internet address is www.magellanlp.com. We make available free of charge on or through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Item 1A. Risk Factors

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

Risks Related to Our Business

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

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

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

Any sustained decrease in demand for petroleum products in the markets served by our pipeline and terminals could result in a significant reduction in the volume of products that we transport, store and distribute, and thereby reduce our cash flow and our ability to pay cash distributions. Economic conditions worldwide have from time to time resulted in reduced demand for the products transported and stored by our pipelines and terminals and the services that we provide. Our financial results may also be affected by uncertain or changing economic conditions within certain regions, including the challenges that have affected economic conditions in the entire United States over the last several years. If economic and market conditions remain uncertain or adverse conditions persist for an extended period, we could experience material impacts on our business, financial condition and results of operations.

Other factors that could lead to a decrease in market demand include:

- an increase in the market prices of crude oil and petroleum products, which may reduce demand for crude oil, gasoline and other petroleum products. Market prices for petroleum products are subject to wide fluctuations in response to changes in global and regional supply and demand over which we have no control;
- higher fuel taxes or other governmental or regulatory actions that increase the cost of the products we handle;
- an increase in fuel economy, whether as a result of a shift by consumers to more fuel-efficient vehicles, technological advances by manufacturers or federal or state regulations; and

- an increase in the use of alternative fuel sources, such as ethanol, biodiesel, fuel cells and solar, electric and battery-powered engines. Current laws will require a significant increase in the quantity of ethanol and biodiesel used in transportation fuels between now and 2022. Such an increase could have a material impact on the volume of petroleum-based fuels transported on our pipeline or distributed through our terminals.

A decrease in lease renewals at substantially lower rates at our storage terminals and at leased storage along our petroleum pipeline system could cause our leased storage revenues to decline, which would adversely impact our results of operations and the amount of cash we generate.

Most of the revenues we earn from our leased storage at our storage terminals and from leased storage along our pipeline system are provided for in contracts negotiated with our leased storage customers. Many of those contracts are for multi-year periods and require our customers to pay a fixed rate for storage capacity regardless of market conditions during the contract period. Changing market conditions, including changes in petroleum product supply or demand patterns, financial market conditions, regulatory, accounting or other factors could cause our customers to be unwilling to renew their leased storage contracts with us when those contracts terminate, or make them willing to renew only at lower rates or for shorter contract periods. Failure by our customers to renew their leased storage contracts on terms and at rates substantially similar to our existing contracts could result in lower utilization of our facilities and could cause our leased storage revenues to be more volatile. We have built a significant amount of new storage to meet market demand in recent years, as have several of our competitors. In addition, storage facilities previously used to support refineries or other facilities have in some cases been redeployed to provide services that compete with our own services. Increased competition from other leased storage facilities could discourage our customers from renewing their contracts with us or cause them to renew their contracts with us at lower rates. We typically make capital investments in leased storage facilities only if we are able to secure contracts from our customers that support such investment; however, in some cases the initial term of those contracts is not sufficient to ensure that we fully earn the return we expect on those investments. If our customers do not renew such contracts or renew on less favorable terms, we could earn a return on those investments that is below our cost of financing, which could adversely affect our results of operations, financial position and cash flows.

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

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

Fluctuations in prices of petroleum products, LPGs and crude oil that we purchase and sell could materially affect our results of operations.

We generate product sales revenues from our petroleum products blending and fractionation activities, as well as from the sale of product generated by the operation of our pipeline and terminals. We also maintain product inventory related to these activities. In addition, we own linefill inventory required for the operation of portions of our pipeline system, and we purchase and sell refined petroleum products and crude oil in connection with the management of that inventory. Significant fluctuations in market prices of petroleum products could result in losses or lower profits from these activities, thereby reducing the amount of cash we generate and our ability to pay cash distributions.

Additionally, significant fluctuations in market prices of petroleum products or crude oil could result in significant unrealized gains or losses on transactions we enter to hedge our commodity exposure. To the extent these transactions have not been designated as hedges for accounting purposes, the associated non-cash unrealized gains and losses would directly impact our results of operations.

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

We hedge our exposure to price fluctuations for our petroleum products and crude oil purchase and sale activities by utilizing physical purchase and sale agreements, futures contracts traded on the NYMEX, options contracts or over-the-counter

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

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

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers to whom we extend credit. In addition, we frequently undertake capital expenditures based on commitments from customers upon which we rely to realize the expected return on those expenditures, and nonperformance by our customers on those commitments could result in substantial losses to us. Similarly, nonperformance by vendors who have committed to provide products or services to us could result in higher costs, reduce our revenues or otherwise interfere with the conduct of our business. We also rely to a significant degree on the banks that lend to us under our revolving credit facility for financial liquidity, and any failure of those banks to perform on their obligations to us could significantly impair our liquidity. Furthermore, nonpayment by the counterparties to our interest rate and commodity derivatives could expose us to additional interest rate or commodity price risk. Any substantial increase in the nonpayment or nonperformance by our customers, vendors, lenders or derivative counterparties could have a material adverse effect on our results of operations, financial position and cash flows and our ability to pay cash distributions.

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

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

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

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

Economic conditions that have persisted during the last several years amplify certain risks inherent in our business.

The U.S. and many other countries have experienced weak economic conditions and frequently volatile financial markets since 2007. During that period, these conditions have periodically resulted in significant reductions in access to capital, and capital constraints coupled with significant energy price volatility and generally weak economic conditions have resulted in

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financial and liquidity issues for many companies, including some of our customers, as well as national, state and municipal governments. Such conditions have created significant uncertainty in the economic outlook and have amplified the potential impact and likelihood of the occurrence of certain risks inherent in our business. Such risks include:

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

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

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

The FERC's ratemaking methodologies may limit our ability to set rates based on our true costs or may delay the use of rates that reflect increased costs. The FERC's primary ratemaking methodology is price indexing. We use this methodology to establish our rates in approximately 40% of our markets. The FERC's indexing methodology is subject to review every five years and currently allows a pipeline to change its rates each year to a new ceiling level, which is calculated as the previous year's ceiling level multiplied by a percentage. For the five-year period ending June 30, 2011, the indexing method required a pipeline to change its rates by a percentage equal to the change in the PPI-FG plus 1.3%. In December 2010, the FERC established a new price index level of PPI-FG plus 2.65% for the five-year period beginning July 1, 2011. Certain shippers have requested a rehearing of this matter by the FERC and other shippers have asked a U.S. court of appeals to review FERC's decision. At this time, management is unable to determine whether the FERC will rehear this matter or whether the court of appeals will review it or what outcome might result should such rehearing or court review occur. If the PPI-FG falls and our rates are at the ceiling level, we would be required to reduce our rates that are based on the FERC's price indexing methodology.

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

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

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

We use the FERC's PPI-based price indexing methodology to establish tariff rates in approximately 40% of the markets served by our petroleum pipeline system. For the five-year period ending June 30, 2011, the indexing method provided for a pipeline to change its rates by a percentage equal to the change in the PPI-FG plus 1.3% and for the five-year period beginning July 1, 2011, the indexing method provides for changes in rates by a percentage equal to the change in the PPI-FG plus 2.65%. Certain shippers have requested a rehearing of this matter by the FERC. At this time, management is unable to determine whether the FERC will rehear this matter or what outcome might result should such rehearing occur. This methodology could

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result in changes in our revenues that do not fully reflect changes in the costs we incur to operate and maintain our petroleum pipeline system. For example, our costs could increase more quickly or by a greater amount than the PPI-FG index plus 2.65% used by the FERC methodology. Further, in periods of general price deflation, the PPI-FG index could fall, in which case we could be required to reduce our index-based rates, even if the actual costs we incur to operate our assets increase. Changes in price levels that lead to decreases in our revenues or increases in the prices we pay to operate and maintain our assets could adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

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

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

Changes in federal, state and local laws and regulations that govern the environmental and operational safety aspects of our operations could increase our costs and liabilities.

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

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

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

Anti-market manipulation laws and related regulations could subject us to significant penalties and related third-party damage claims.

We are required to observe anti-market manipulation laws and related regulations enforced by the FTC and CFTC and to comply with FERC rate regulation. The FTC and CFTC hold substantial enforcement authority under the anti-market manipulation laws and regulations, including the ability to assess civil penalties of up to $1 million per day per violation. The FTC, CFTC and FERC also have authority to order disgorgement of profits or refunds and to recommend criminal penalties. Should we violate these laws and regulations, we could also be subject to related third-party damage claims.

Potential regulations under the Dodd-Frank Act regarding derivatives could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price risk and other risks associated with our business.

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”), was signed into law which, among other things, establishes federal oversight and regulation of the over-the-counter derivatives market and the entities, such as us, that participate in that market. Significant regulations are required to be promulgated by the SEC and the Commodity Futures Trading Commission within 360 days from the date of enactment to implement the new legislation. The new legislation, to the extent applicable to us or our derivative counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to hedge and otherwise manage our financial and commercial risks related to fluctuations in commodity prices, and could have an adverse effect on our ability to hedge risks associated with our business. Many of the key concepts and processes under the Dodd-Frank Act are not defined and must be delineated by rules and regulations to be adopted by the applicable regulatory agencies. As a consequence, it is not possible at this time to predict the effects that the Dodd-Frank Act or the resulting rules and regulations may have on our hedging activities.

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

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. Accordingly, the EPA had proposed two sets of CAA regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, in October 2009, the EPA issued a final CAA rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including sources that emit more than 25,000 tons of greenhouse gases on an annual basis, beginning in 2011 for emissions occurring in 2010. In June 2010, the EPA issued a final rule addressing greenhouse gas emissions in permits for major stationary sources of air emissions, which may ultimately result in emission controls. In November 2010, the EPA adopted a final rule requiring reporting of greenhouse gases from certain oil and gas facilities beginning in 2012 for emissions occurring in 2011. The adoption and implementation of any CAA regulations limiting emissions of greenhouse gases from our equipment and operations or those of customers for whom we transport, store or deliver product, could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for our services.

In addition, Congress has actively considered various proposals to reduce greenhouse gas emissions that may impose a carbon emissions tax, a cap-and-trade program or other programs aimed at carbon reduction, including the American Clean Energy and Security Act passed by the U.S. House of Representatives in June 2009 and a similar bill in the U.S. Senate. Either bill would have established an economy-wide "cap-and-trade" program to reduce U.S. emissions of greenhouse gases. Future laws might require reduction in greenhouse gas emissions by 2020 with a further reduction of such emissions by 2050. The U.S. Senate has considered similar cap-and-trade legislation, and Congress may consider these or similar legislation. Allowances under a future cap-and-trade program would be expected to escalate significantly in cost over time. The net effect of such potential legislation would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products and natural gas. The Obama Administration has indicated its support of legislation to reduce greenhouse gas emissions through an emission allowance system. In addition, at least one-third of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap and trade programs. It is not possible at this time to predict whether or when Congress will adopt climate change legislation, or how state and federal legal and regulatory initiatives will interact.

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

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

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

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

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

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

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

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

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

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

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

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

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

From time to time, we evaluate and acquire assets and businesses that we believe complement our existing assets and businesses. Acquisitions may require substantial equity capital or us to incur 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

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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.

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

The storage and pipeline assets we acquired from BP depend on facilities owned and operated by others and on a limited number of customers.

The crude oil pipeline system and the refined petroleum pipeline system that we acquired from BP both depend to a substantial degree on the operation of the Texas City, Texas refineries to which those systems are connected, resulting in significant exposure to the performance of the owners of those refineries. In addition, those systems rely on connections to various other pipelines owned and operated by others for supply and distribution of the crude oil and refined petroleum products transported on those systems. Outages at the Texas City, Texas refineries or reduced or interrupted throughput on these connecting pipelines because of weather-related or other natural causes, testing, line repair, damage, reduced operating pressures or other causes could reduce the shipments on the pipeline systems we have acquired, which could adversely affect our cash flows and our ability to pay distributions.

The crude oil storage assets that we acquired from BP in Cushing, Oklahoma have been leased solely by an affiliate of the seller of those assets, and we are subject to risks of loss from nonpayment by that customer. In addition, any decision by that customer not to renew its lease at the end of the original lease term could result in a reduction of the revenues we receive related to those assets, which could adversely affect our cash flows and our ability to pay distributions.

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

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

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

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

In addition, changes in the product quality of the products we receive on our petroleum pipeline system, or changes in the product specifications in the markets we serve, could reduce or eliminate our ability to blend products, which would result in a

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reduction of our revenues and operating profit from blending activities. Any such reduction of our revenues or operating profit could have an adverse effect on our results of operations, financial position, cash flows and ability to pay cash distributions.

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

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

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

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

Increases in interest rates could increase our financing costs and reduce the amount of cash we generate, and could adversely affect the trading price of our units.

As of December 31, 2010, we had $1,865.0 million of debt outstanding (excluding unamortized discounts and premiums on debt issuances and the unamortized portion of fair value hedges). Of this amount, borrowings outstanding on our revolving credit facility of approximately $15.0 million were subject to variable interest rates. We also expect to make additional floating-rate borrowings under our revolving credit facility to partially finance future expansion capital spending. As a result, we have exposure to changes in short-term interest rates. We may also use interest rate derivatives to effectively convert some of our fixed-rate notes to floating-rate debt, thereby increasing our exposure to changes in short-term interest rates. In addition, the execution of our growth strategy and the refinancing of our existing debt could require that we issue additional fixed-rate debt, and consequently we also have potential exposure to changes in long-term interest rates. Rising interest rates could reduce the amount of cash we generate and adversely affect our liquidity and our ability to pay cash distributions. Moreover, the trading price of our units is sensitive to changes in interest rates and could be adversely affected by any increase in interest rates.

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

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

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

Our partnership agreement requires our general partner's board of directors 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's board of directors to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to our unitholders.

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

We currently have a unit purchase rights plan, commonly referred to as a “poison pill.” This poison pill will cause substantial dilution to the ownership of a person or group that attempts to acquire us on terms not approved by our general partner's board of directors and may have the effect of deterring future takeover attempts. The practical effect of a poison pill is to require a party seeking control of us to negotiate with our general partner's board of directors, which could delay or prevent a change in control of us and the replacement or removal of management. This poison pill, coupled with other anti-takeover provisions in our partnership agreement and under Delaware law, could discourage a future takeover attempt which individual

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unitholders might deem to be in their best interests or in which unitholders would receive a premium for their limited partner units over current prices.

Tax Risks to Limited Partner Unitholders

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

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

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

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

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

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. For example, at the federal level, members of the U.S. Congress have recently considered substantive changes to the existing federal income tax laws that would have affected certain publicly traded partnerships. Although the most recently proposed legislation would not appear to affect us, such legislation could be reintroduced and amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these changes, or other proposals, will be reintroduced or will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact a unitholder's investment in our limited partner units. At the state level, changes in current state law may subject us to additional entity-level taxation by individual states. Specifically, because of widespread state budget deficits and for other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may reduce the cash available for distribution to our unitholders.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

We will be considered to have technically terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same unit are counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year, and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year results in more than twelve months of our taxable income or loss being includable in the unitholder's taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes. The IRS has recently announced a publicly traded partnership technical termination relief program whereby, if the taxpayer requests relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

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

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

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

Item 3. Legal Proceedings

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

Item 4. Reserved

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PART II

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

Our limited partner units are listed and traded on the New York Stock Exchange ("NYSE") under the ticker symbol "MMP." At the close of business on February 1, 2011, we had 112,736,571 limited partner units outstanding that were owned by approximately 100,000 record holders and beneficial owners (held in street name).

The year-end closing sales price of our limited partner units was $43.33 on December 31, 2009 and $56.50 on December 31, 2010. The high and low trading prices for our limited partner units and distribution paid per unit by quarter for 2009 and 2010 were as follows:

	2009			2010		
Quarter	High	Low	Distribution*	High	Low	Distribution*
1st	$36.00	$25.36	$0.7100	$47.65	$39.81	$0.7200
2nd	$36.75	$28.93	$0.7100	$48.60	$39.85	$0.7325
3rd	$39.92	$33.75	$0.7100	$51.47	$45.55	$0.7450
4th	$43.70	$36.55	$0.7100	$57.43	$51.45	$0.7575

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

We must distribute all of our available cash, as defined in our partnership agreement, at the end of each quarter, less reserves established by our general partner. We currently pay quarterly cash distributions of $0.7575 per limited partner unit. In general, we intend to increase our cash distribution; however, we cannot guarantee that future distributions will increase or continue at current levels. A portion of the cash we had on hand at December 31, 2010 was restricted (see Note 1–Organization and Description of Business in the accompanying financial statements).

Unitholder Return Performance Presentation

The following graph compares the total unitholder return performance of our limited partner units with the performance of (i) the Standard & Poor's 500 Stock Index ("S&P 500") and (ii) the Alerian MLP index[1]. The graph assumes that $100 was invested in our limited partner units and each comparison index beginning on December 30, 2005 and that all distributions or dividends were reinvested on a quarterly basis.

[1] The Alerian MLP Index is a composite of the 50 most prominent energy master limited partnerships that provides investors with a comprehensive benchmark for this asset class.

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	12/30/2005	12/29/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010
Magellan Midstream Partners, L.P.	$100.0	$128.0	$152.1	$114.1	$176.9	$245.0
Alerian MLP Index	$100.0	$126.1	$142.1	$89.6	$158.1	$214.8
S&P 500	$100.0	$115.8	$122.1	$77.0	$97.3	$111.9

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

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Item 6. Selected Financial Data

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

Our operating results incorporate a number of significant estimates and uncertainties. Such matters could cause the data included herein not to be indicative of our future financial conditions or results of operations. A discussion of our critical accounting estimates and how these estimates could impact future financial conditions and results of operations is included in Management's Discussion and Analysis of Financial Condition and Results of Operations under Item 7 of this report. In addition, a discussion of the risk factors which could affect our business and future financial condition and results of operations is included under Item 1A Risk Factors of this report. Additionally, Note 2-Summary of Significant Accounting Policies under Item 8, Financial Statements and Supplementary Data of this report provides descriptions of areas where estimates and judgments could result in different amounts recognized in our accompanying consolidated financial statements.

We present the financial measure of distributable cash flow ("DCF"), which is not a generally accepted accounting principles ("GAAP") measure, in the following tables. Our partnership agreement requires that all of our available cash, less amounts reserved by our general partner's board of directors, be distributed to our limited partners. Management uses distributable cash flow to determine the amount of available cash that our operations generated that is available for distribution to our limited partners. A reconciliation of DCF to net income, the nearest comparable GAAP measure, is included in the following schedules.

In addition to DCF, 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 using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the following table. See Note 16–Segment Disclosures in the accompanying consolidated financial statements for a reconciliation of segment operating margin to segment operating profit. Operating margin is an important measure of the economic performance of our core operations and we believe that investors benefit from having access to the same financial measures utilized by management. Operating profit, alternatively, includes expense items such as depreciation and amortization expense and general and administrative (“G&A”) expense, that management does not consider when evaluating the core profitability of an operation.

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	Year Ended December 31,				
	2006	2007	2008	2009	2010
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenues	$559,321	$608,781	$638,810	$678,945	$793,599
Product sales revenues	664,569	709,564	574,095	334,465	763,090
Affiliate management fee revenues	690	712	733	761	758
Total revenues	1,224,580	1,319,057	1,213,638	1,014,171	1,557,447
Operating expenses	243,860	250,935	264,871	257,635	282,212
Product purchases	605,341	633,909	436,567	280,291	668,585
Gain on assignment of supply agreement	—	—	(26,492)	—	—
Equity earnings	(3,324)	(4,027)	(4,067)	(3,431)	(5,732)
Operating margin	378,703	438,240	542,759	479,676	612,382
Depreciation and amortization expense	76,200	79,140	86,501	97,216	108,668
G&A expense	69,503	74,859	73,302	84,049	95,316
Operating profit	233,000	284,241	382,956	298,411	408,398
Interest expense, net	47,624	47,653	50,479	69,187	93,296
Debt prepayment premium	—	1,984	—	—	—
Debt placement fee amortization	1,925	1,554	767	1,112	1,401
Other (income) expense, net	653	728	(380)	(24)	750
Income before provision for income taxes	182,798	232,322	332,090	228,136	312,951
Provision for income taxes[a]	—	1,568	1,987	1,661	1,371
Net income	$182,798	$230,754	$330,103	$226,475	$311,580
Net income allocation:[b]					
Portion applicable to ownership interests before completion of initial public offering[c]	$5,886	$—	$—	$—	$—
Non-controlling owners' interest	148,292	175,356	244,430	99,729	(397)
Limited partner interests	33,069	61,580	87,733	126,746	311,977
General partner interest	(4,449)	(6,182)	(2,060)	—	—
Net income	$182,798	$230,754	$330,103	$226,475	$311,580
Basic and diluted net income per limited partner unit	$0.83	$1.55	$2.21	$2.22	$2.85
Balance Sheet Data:					
Working capital (deficit)[d]	$(310,087)	$(15,609)	$(29,644)	$94,571	$109,536
Total assets	2,316,508	2,416,931	2,600,708	3,163,148	3,717,900
Long-term debt[d]	518,609	914,536	1,083,485	1,680,004	1,906,148
Owners' equity	1,165,775	1,184,566	1,254,132	1,196,354	1,469,571
Cash Distribution Data:					
Cash distributions declared per MMP unit[e]	$2.34	$2.55	$2.77	$2.84	$2.96
Cash distributions paid per MMP unit[e]	$2.29	$2.49	$2.72	$2.84	$2.91

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	Year Ended December 31,				
	2006	2007	2008	2009	2010
	(in thousands, except per unit amounts and operating statistics)				
Other Data:					
Operating margin (loss):					
Petroleum pipeline system	$287,574	$354,914	$428,903	$361,598	$480,781
Petroleum terminals	84,992	83,289	101,713	110,573	132,748
Ammonia pipeline system	2,554	(2,995)	8,660	3,666	(4,156)
Allocated partnership depreciation costs[f]	3,583	3,032	3,483	3,839	3,009
Operating margin	$378,703	$438,240	$542,759	$479,676	$612,382
Distributable cash flow:					
Net income	$182,798	$230,754	$330,103	$226,475	$311,580
Depreciation and amortization expense[g]	78,125	80,694	87,268	98,328	110,069
Equity-based incentive compensation expense[h]	10,820	6,213	931	6,123	15,499
Asset retirements and impairments	8,031	8,548	7,180	5,529	1,062
Commodity-related adjustments:					
NYMEX losses (gains) recognized in the current period associated with products that will be sold in the future[i]	—	—	(20,200)	10,475	14,945
NYMEX losses (gains) recognized in previous periods associated with products that were sold in the current period[j]	—	—	—	20,200	(7,675)
Lower-of-cost-or-market adjustments	—	—	6,413	(6,413)	—
Houston-to-El Paso cost of sales adjustment[k]	—	—	—	—	478
Maintenance capital	(26,160)	(31,243)	(43,232)	(37,999)	(44,620)
Expenses paid by (credited to) a former affiliate[l]	13,652	10,617	(4,344)	5,144	—
Product supply agreement gains[m]	(2,563)	(2,563)	(26,919)	—	—
Other	(6,960)	(4,876)	1,013	541	(1,579)
Distributable cash flow	$257,743	$298,144	$338,213	$328,403	$399,759
Operating Statistics:					
Petroleum pipeline system:					
Transportation revenue per barrel shipped	$1.060	$1.147	$1.193	$1.205	$1.160
Volume shipped (million barrels)[n]	309.6	307.2	295.9	295.7	359.5
Petroleum terminals:					
Storage terminal (formerly marine terminal) average utilization (million barrels per month)	18.9	19.9	21.4	23.5	25.8
Inland terminal throughput (million barrels)	110.1	117.3	108.1	109.8	114.7
Ammonia pipeline system:					
Volume shipped (thousand tons)	726	716	822	643	462

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

(b) Prior to September 28, 2009, the date the simplification of our capital structure closed (see Note 2–Summary of Significant Accounting Policies in the accompanying notes to consolidated financial statements for a discussion of the simplification), net income allocations were as follows:

•

Non-controlling owners’ interest was our net income allocated to owners other than Magellan Midstream Holdings, L.P. ("Holdings"), the owner of our general partner at that time;

- Limited partner interests was net income allocated to Holdings' limited partner unitholders; and
- General partner interest was the net loss allocated to Holdings' general partner.

Following the simplification, the non-controlling owners’ interest was eliminated and all of our net income was allocated to our limited partners

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until the formation of Magellan Crude Oil, LLC in 2010, which was partially owned by a private investment group.

(c) Prior to the simplification of our capital structure in September 2009, these financial statements were those of Holdings, which at that time was the owner of our general partner. As our general partner, Holdings fully consolidated our financial results. Holdings was taken public in February 2006. This represents income allocable to the owners of Holdings prior to its initial public offering in February 2006.

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

(e) 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.

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

(g) Includes debt placement fee amortization.

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

(i) Certain derivatives we use as economic hedges do not qualify for hedge accounting treatment. We recognize the change in fair value of these agreements each accounting period in our earnings, even if the hedged product has not yet been physically sold. These amounts represent the gains or losses of hedged products recognized in our earnings for products that we have not yet physically sold.

(j) When we physically sell products that we have economically hedged (but did not qualify for hedge accounting treatment), we include in our DCF calculations the full amount of the change in fair value of the associated derivative agreement.

(k) Cost of goods sold adjustment related to transitional commodity activities for our Houston-to-El Paso pipeline to more closely resemble current market prices for distributable cash flow purposes rather than average inventory costing as used to determine our results of operations.

(l) In periods prior to the completion of our simplification in September 2009, we had agreements with our general partner and its affiliates that provided reimbursement for (i) certain general and administrative costs above specified amounts and (ii) certain environmental costs that were subject to an environmental indemnification settlement in 2004. In addition, our general and administrative costs included non cash expenses to us for a payment made by our general partner's affiliate to one of our executive officers. In 2008, we negotiated a settlement with the EPA for environmental matters that were part of the 2004 indemnification settlement. The settlement was for an amount less than had been previously accrued for these matters, which consequently reduced expenses and increased net income.

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

(n) Excludes capacity leases.

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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 petroleum products and crude oil. As of December 31, 2010, our three operating segments included:

- petroleum pipeline system, comprised of approximately 9,600 miles of pipeline and 51 terminals;
- petroleum terminals, which includes storage terminal facilities (consisting of six marine terminals located along coastal waterways and crude oil storage in Cushing, Oklahoma) and 27 inland terminals; and
- ammonia pipeline system, representing our 1,100-mile ammonia pipeline and six associated terminals.

Beginning in 2010, our East Houston, Texas terminal was transferred from our petroleum terminals segment to our petroleum pipeline system segment due to its increasing usage as a pipeline terminal. Since the beginning of 2010, this facility has been under petroleum pipeline management and its operating results have been reported as part of that segment. As a result, historical financial results for our segments have been adjusted to conform to the current period's presentation. This historical reclassification did not materially impact segment financial results and did not change consolidated financial results.

The following discussion provides an analysis of the results for each of our operating segments, an overview of our liquidity and capital resources and other items related to our partnership. The following discussion and analysis should be read in conjunction with our consolidated financial statements and related notes included in this Annual Report on Form 10-K for the year ended December 31, 2010.

Recent Developments

Changes in our Executive Officers. Effective February 1, 2011, our chief executive officer, Don R. Wellendorf, retired. The board of directors of our general partner elected Michael N. Mears, formerly our chief operating officer, as chief executive officer and chairman of the board of directors of our general partner. Jeff Selvidge was named senior vice president of Transportation and Terminals effective February 14, 2011, and has assumed a number of the responsibilities formerly performed by Mr. Mears in his role as chief operating officer.

One of our executive officers, Richard A. Olson, senior vice president, operations and technical services, has announced his departure effective March 1, 2011. Larry J. Davied was named senior vice president of Operations and Technical Services effective February 14, 2011, to replace Mr. Olson.

Cash Distribution. On January 27, 2011, the board of directors of our general partner declared a quarterly cash distribution of $0.7575 per unit for the period of October 1, 2010 through December 31, 2010. This quarterly cash distribution was paid on February 14, 2011 to unitholders of record on February 7, 2011. The total distributions paid on 112.7 million limited partner units outstanding was $85.4 million.

Acquisition of Petroleum Storage and Pipelines. On September 1, 2010, we acquired petroleum storage and pipeline assets from BP Pipelines (North America), Inc. (“BP”) for $291.3 million. The storage assets acquired consisted of approximately 7.8 million barrels of crude oil storage in Cushing, Oklahoma. In addition, during October 2010, we acquired crude oil working inventories associated with the Cushing crude oil storage assets from BP that had a market value of approximately $53.0 million. The pipeline assets acquired from BP consisted of nearly 40 miles of common carrier crude oil pipelines between Houston and Texas City, Texas and two 35-mile common carrier pipelines that transport refined petroleum products from the Texas City refining region to the Houston, Texas area, including connections to third-party pipelines for delivery to other end-use markets. The acquisition was financed with the proceeds of equity and debt offerings completed during the third quarter of 2010 (see Equity and Debt Offerings, below).

Equity and Debt Offerings. In July 2010, we completed a public offering of 5,750,000 of our common units at $46.65 per unit and received net proceeds of approximately $258.4 million after underwriting discounts of $9.5 million and offering expenses of $0.3 million. In August 2010, we issued $300.0 million of 4.25% notes due 2021 in an underwritten public offering. The notes were issued for the discounted price of 99.6%, or $298.9 million, and net proceeds from this offering, after underwriter discounts of $2.0 million and offering costs of $0.4 million, were $296.5 million. The combined net proceeds from

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these offerings of $554.9 million were used to pay the $291.3 million purchase price of our acquisition of petroleum storage and pipeline assets from BP in September 2010. We also acquired associated crude oil working inventories that had a market value of approximately $53.0 million in October 2010. The remaining proceeds were used to repay the outstanding balance at that time of $175.5 million on our revolving credit facility and for general partnership purposes.

Magellan Crude Oil, LLC. In May 2010, we formed Magellan Crude Oil, LLC (“MCO”), a Delaware limited liability company, for the purpose of constructing and operating crude oil storage in the Cushing, Oklahoma crude oil hub for lease to third parties. At December 31, 2010, approximately 35% of the common equity of MCO was owned by a private investment group and approximately 65% was owned by us. In addition, we owned all of MCO's cumulative preferred equity. Through December 31, 2010, we have contributed cash of $35.4 million to MCO, of which $9.3 million was recorded as cumulative preferred equity and $26.1 million was recorded as common equity. The private investment group's investment in MCO through December 31, 2010 was $14.3 million. At the time of MCO's formation, we determined that it was not a variable interest entity and subsequently we concluded that it should be consolidated into our results based on our voting and operational control of that entity. Since we consolidate MCO, non-controlling owners' interest in consolidated subsidiaries on our consolidated balance sheet as of December 31, 2010 reflects the contributions to MCO by the private investment group less their allocated share of MCO's net losses for the 2010 fiscal year. The results of MCO have been included in our petroleum terminals segment from the date of its formation. In February 2011, we acquired the private investment group's common equity in MCO for $40.5 million.

Overview

Our petroleum pipeline system and petroleum terminals generate the majority of our operating margin from the transportation and storage services we provide to our customers. The revenues generated from these businesses are significantly influenced by demand for refined petroleum products and crude oil. In addition, we generate operating margin from commodity-related activities. Operating expenses are principally fixed costs related to routine maintenance and system integrity as well as field and support personnel. Other costs, including power, fluctuate with volumes transported on our pipeline and stored in our terminals. Expenses resulting from environmental remediation projects include costs from projects relating both to current and past events.

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

Petroleum Pipeline System. Our petroleum pipeline system is comprised of a common carrier pipeline that provides transportation, storage and distribution services for petroleum products in 13 states from Texas through the Midwest to Colorado, North Dakota, Minnesota, Wisconsin and Illinois. Through direct refinery connections and interconnections with other interstate pipelines, our petroleum pipeline system can access more than 44% of the refinery capacity in the continental United States. In 2010, the pipeline generated 72% of its revenues, excluding the sale of petroleum products, through transportation tariffs for petroleum volumes shipped. These tariffs vary depending upon where the product originates, where ultimate delivery occurs and any applicable discounts. All interstate transportation rates and discounts are in published tariffs filed with the Federal Energy Regulatory Commission (“FERC”). The pipeline also earns revenues from non-tariff based activities including leasing pipeline and storage tank capacity to shippers and by providing data services and product services such as ethanol and biodiesel unloading and loading, additive injection, custom blending and laboratory testing.

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

Petroleum Terminals. Our petroleum terminals segment is comprised of storage terminals and inland terminals, which store and distribute petroleum products throughout 13 states. Our storage terminals are comprised of six facilities that have marine access and are located near major refining hubs along the U.S. Gulf and East Coasts. We also have a crude oil terminal in Cushing, Oklahoma, one of the largest crude oil trading hubs in the United States. These storage terminals principally serve refiners, marketers and traders. We earn revenues at our storage terminals 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 and ethanol blending.

Ammonia Pipeline System. Our ammonia pipeline system transports and distributes ammonia from production facilities in Texas and Oklahoma to various distribution points in the Midwest for use as an agricultural fertilizer. We generate revenues principally from volume-based fees for the transportation of ammonia on our pipeline system.

Acquisitions

We significantly increased our operations during 2010 through the following acquisitions:

- In April 2010, the acquisition of various petroleum products storage tanks already connected to our petroleum pipeline system at Des Moines, Iowa, El Dorado, Kansas and Glenpool and Tulsa, Oklahoma for $29.3 million.
- In September 2010, the acquisition from BP of 7.8 million barrels of crude oil storage in the Cushing, Oklahoma area and more than 100 miles of petroleum pipelines in the Houston, Texas area for $291.3 million.

Growth Projects

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

- strong demand for petroleum products and crude oil storage, which has provided significant opportunity for us to build tankage along our petroleum pipeline system and at our storage terminals, backed by long-term customer commitments; and
- demand for enhanced connectivity to key growth markets. We are expanding our crude oil logistics infrastructure in the Cushing, Oklahoma and Houston, Texas markets. The assets acquired from BP will facilitate our strategy of developing our existing East Houston terminal into a key distribution point for crude oil to Gulf Coast refineries by improving our connectivity within the Houston market and extending our reach to the Texas City refining region.

We spent $549.8 million and $480.1 million on acquisitions and growth projects during 2010 and 2009, respectively. Further, we currently expect to spend approximately $215.0 million in 2011 on projects now underway, with additional spending of approximately $30.0 million thereafter to complete these projects. These expansion capital estimates exclude potential acquisitions or spending on more than $500.0 million of other potential growth projects in earlier stages of development.

Results of Operations

We believe that investors benefit from having access to the same financial measures utilized by management. Operating margin, which is presented in the following tables, is an important measure used by management to evaluate the economic performance of our core operations. Operating margin is not a generally accepted accounting principles (“GAAP”) measure, but the components of operating margin are computed using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the following tables. Operating profit includes expense items, such as depreciation and amortization expense and general and administrative ("G&A") costs, which management does not consider when evaluating the core profitability of our operations. Additionally, product margin, which management primarily uses to evaluate the profitability of our commodity-related activities, is provided in these tables. Product margin is a non-GAAP measure; however, its components of product sales and product purchases are determined in accordance with GAAP.

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Year Ended December 31, 2009 Compared to Year Ended December 31, 2010

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2009	2010	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum pipeline system	$494.2	$584.0	$89.8	18%
Petroleum terminals	167.0	196.7	29.7	18%
Ammonia pipeline system	19.9	14.9	(5.0)	(25)%
Intersegment eliminations	(2.2)	(2.0)	0.2	9%
Total transportation and terminals revenues	678.9	793.6	114.7	17%
Affiliate management fee revenues	0.8	0.8	—	—%
Operating expenses:				
Petroleum pipeline system	181.0	191.0	(10.0)	(6)%
Petroleum terminals	64.3	75.2	(10.9)	(17)%
Ammonia pipeline system	16.2	19.1	(2.9)	(18)%
Intersegment eliminations	(3.9)	(3.1)	(0.8)	21%
Total operating expenses	257.6	282.2	(24.6)	(10)%
Product margin:				
Product sales	334.5	763.1	428.6	128%
Product purchases	280.3	668.6	(388.3)	(139)%
Product margin	54.2	94.5	40.3	74%
Equity earnings	3.4	5.7	2.3	68%
Operating margin	479.7	612.4	132.7	28%
Depreciation and amortization expense	97.2	108.7	(11.5)	(12)%
G&A expense	84.1	95.3	(11.2)	(13)%
Operating profit	298.4	408.4	110.0	37%
Interest expense (net of interest income and interest capitalized)	69.2	93.3	(24.1)	(35)%
Debt placement fee amortization	1.1	1.4	(0.3)	(27)%
Other (income) expense	(0.1)	0.7	(0.8)	n/a
Income before provision for income taxes	228.2	313.0	84.8	37%
Provision for income taxes	1.7	1.4	0.3	18%
Net income	$226.5	$311.6	$85.1	38%
Operating Statistics				
Petroleum pipeline system:				
Transportation revenue per barrel shipped	$1.205	$1.160		
Volume shipped (million barrels)[(a)]	295.7	359.5		
Petroleum terminals:				
Storage terminal (formerly marine terminal) average utilization (million barrels per month)	23.5	25.8		
Inland terminal throughput (million barrels)	109.8	114.7		
Ammonia pipeline system:				
Volume shipped (thousand tons)	643	462		

(a) Excludes capacity leases.

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Transportation and terminals revenues increased by $114.7 million, resulting from:

- an increase in petroleum pipeline system revenues of $89.8 million primarily attributable to higher transportation revenues, higher pipeline capacity and storage lease revenues and incremental fees for terminal throughput, ethanol blending and additives. Transportation revenues increased primarily as a result of higher diesel fuel volumes driven by improved economic conditions and additional volumes from recent acquisitions and growth projects, as well as higher tariff rates due to the mid-2009 tariff escalation. Overall transportation revenue per barrel shipped declined between periods because the tariffs related to the Texas pipelines acquired from BP in September 2010 are significantly lower than our remaining pipeline system due to the short distance of the pipeline movements between Houston and Texas City, Texas. Excluding the recently-acquired pipelines, transportation rates increased for the remainder of our pipeline system by $0.07 per barrel, or 6%, primarily due to longer haul shipments;

- an increase in petroleum terminals revenues of $29.7 million due to higher revenues at both our storage and inland terminals. Storage terminal revenues increased principally due to higher rates on existing storage, leasing new storage tanks placed in service over the past year and the acquisition of storage in Cushing, Oklahoma. Inland revenues benefited from higher fees due to ethanol blending and increased throughput volumes; and

- a decrease in ammonia pipeline system revenues of $5.0 million due to lower shipments resulting from the hydrostatic testing performed on our pipeline this year, which rendered the pipeline unavailable for shipments for much of 2010.

Operating expenses increased by $24.6 million, resulting from:

- an increase in petroleum pipeline system expenses of $10.0 million due primarily to higher operating expenses related to our Houston-to-El Paso pipeline section (which we acquired in third quarter 2009) and higher power costs resulting from increased shipments;

- an increase in petroleum terminals expenses of $10.9 million primarily related to higher asset maintenance, environmental and personnel costs; and

- an increase in ammonia pipeline system expenses of $2.9 million due primarily to an increase in asset integrity costs from the hydrostatic testing performed on our pipeline during 2010.

Product sales revenues primarily resulted from our petroleum products blending activities, product marketing and linefill management associated with our Houston-to-El Paso pipeline section, terminal product gains and transmix fractionation. We utilize New York Mercantile Exchange ("NYMEX") contracts to hedge against changes in the future price of petroleum products related to these activities. The period change in the mark-to-market value of these contracts that do not qualify for hedge accounting treatment plus the effective portion of the change in value of matured NYMEX contracts that qualified for hedge accounting treatment are also included in product sales revenues. Product margin increased $40.3 million primarily due to the timing of the recognition of gains and losses from our NYMEX contracts. Due to mark-to-market adjustments on NYMEX contracts, much of the profit related to the commodity sales activity during the 2009 period was recognized in late 2008. Product margin also increased in the current year due to higher profits from our petroleum products blending and fractionation activities as well as profits from our linefill management activities associated with our Houston-to-El Paso pipeline section, and the sale of terminal product overages at higher prices.

Equity earnings increased $2.3 million due primarily to increased shipments on a crude oil pipeline in which we own a 50% interest.

Depreciation and amortization expense increased by $11.5 million primarily due to expansion capital projects and acquisitions over the past year.

G&A expense increased by $11.2 million between periods primarily due to higher equity-based incentive compensation costs, resulting from actual results significantly exceeding the financial performance goals established by the compensation committee of our general partner's board of directors.

Interest expense, net of interest income and interest capitalized, increased $24.1 million in 2010. Our average debt outstanding increased to $1.9 billion for 2010 from $1.4 billion for 2009 principally due to borrowings for expansion capital expenditures and recent acquisitions. The weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, was essentially unchanged at 5.4% from 2009 to 2010.

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

	Year Ended December 31,		Variance Favorable (Unfavorable)	
	2008	2009	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum pipeline system	$478.5	$494.2	$15.7	3%
Petroleum terminals	138.7	167.0	28.3	20%
Ammonia pipeline system	22.7	19.9	(2.8)	(12)%
Intersegment eliminations	(1.1)	(2.2)	(1.1)	(100)%
Total transportation and terminals revenues	638.8	678.9	40.1	6%
Affiliate management fee revenues	0.7	0.8	0.1	14%
Operating expenses:				
Petroleum pipeline system	195.3	181.0	14.3	7%
Petroleum terminals	59.1	64.3	(5.2)	(9)%
Ammonia pipeline system	14.1	16.2	(2.1)	(15)%
Intersegment eliminations	(3.7)	(3.9)	0.2	(5)%
Total operating expenses	264.8	257.6	7.2	3%
Product margin:				
Product sales	574.1	334.5	(239.6)	(42)%
Product purchases	436.6	280.3	(156.3)	36%
Product margin	137.5	54.2	(83.3)	(61)%
Gain on assignment of supply agreement	26.5	—	(26.5)	(100)%
Equity earnings	4.1	3.4	(0.7)	(17)%
Operating margin	542.8	479.7	(63.1)	(12)%
Depreciation and amortization expense	86.5	97.2	(10.7)	(12)%
G&A expense	73.3	84.1	(10.8)	(15)%
Operating profit	383.0	298.4	(84.6	