PART I

Items 1 and 2. *Business and Properties*

General

Plains All American Pipeline, L.P. is a Delaware limited partnership formed in September 1998. Our operations are conducted directly and indirectly through our primary operating subsidiaries. As used in this Form 10-K, the terms "Partnership," "Plains," "we," "us," "our," "ours" and similar terms refer to Plains All American Pipeline, L.P. and its subsidiaries, unless the context indicates otherwise.

We are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products. We refer to liquefied petroleum gas and other natural gas related petroleum products collectively as "LPG." Through our 50% equity ownership in PAA/Vulcan Gas Storage, LLC ("PAA/Vulcan"), we develop and operate natural gas storage facilities.

Prior to the fourth quarter of 2006, we managed our operations through two segments. Due to our growth, especially in the facilities portion of our business (most notably in conjunction with the Pacific acquisition), we have revised the manner in which we internally evaluate our segment performance and decide how to allocate resources to our segments. As a result, we now manage our operations through three operating segments: (i) Transportation, (ii) Facilities, and (iii) Marketing.

Transportation — Our transportation segment operations generally consist of fee-based activities associated with transporting volumes of crude oil and refined products on pipelines and gathering systems. We generate revenue through a combination of tariffs, third-party leases of pipeline capacity, transportation fees, barrel exchanges and buy/sell arrangements.

As of December 31, 2006, we employed a variety of owned or leased long-term physical assets throughout the United States and Canada in this segment, including approximately:

- 20,000 miles of active pipelines and gathering systems;
- 30 million barrels of tank capacity used primarily to facilitate pipeline throughput; and
- 57 transport and storage barges and 30 transport tugs through our 50% interest in Settoon Towing, LLC ("Settoon Towing").

We also include in this segment our equity earnings from our investments in the Butte Pipe Line Company ("Butte") and Frontier Pipeline Company ("Frontier") pipeline systems, in which we own minority interests, and Settoon Towing, in which we own a 50% interest.

Facilities — Our facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products and LPG, as well as LPG fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements.

As of December 31, 2006, we owned and employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 30 million barrels of active, above-ground terminalling and storage facilities;
- approximately 1.3 million barrels of active, underground terminalling and storage facilities; and
- a fractionation plant in Canada with a processing capacity of 4,400 barrels per day, and a fractionation and isomerization facility in California with an aggregate processing capacity of 22,000 barrels per day.

At year-end 2006, we were in the process of constructing approximately 12.5 million barrels of additional above-ground terminalling and storage facilities, the majority of which we expect to place in service during 2007.

Our facilities segment also includes our equity earnings from our investment in PAA/Vulcan. At December 31, 2006, PAA/Vulcan owned and operated approximately 25.7 billion cubic feet of underground storage capacity and is constructing an additional 24 billion cubic feet of underground storage capacity, which is expected to be placed in service in stages over the next three years.

Marketing — Our marketing segment operations generally consist of the following merchant activities:

- the purchase of U.S. and Canadian crude oil at the wellhead and the bulk purchase of crude oil at pipeline and terminal facilities, as well as the purchase of foreign cargoes at their load port and various other locations in transit;
- the storage of inventory during contango market conditions;
- the purchase of refined products and LPG from producers, refiners and other marketers;
- the resale or exchange of crude oil, refined products and LPG at various points along the distribution chain to refiners or other resellers to maximize profits; and
- arranging for the transportation of crude oil, refined products and LPG on trucks, barges, railcars, pipelines and ocean-going vessels to our terminals and third-party terminals.

Our marketing activities are designed to produce a stable baseline of results in a variety of market conditions, while at the same time providing upside exposure to opportunities inherent in volatile market conditions. These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies to reduce the negative impact of market volatility and provide counter-cyclical balance.

Except for pre-defined inventory positions, our policy is generally to purchase only product for which we have a market, to structure our sales contracts so that price fluctuations do not materially affect the segment profit we receive, and not to acquire and hold physical inventory, futures contracts or other derivative products for the purpose of speculating on commodity price changes.

In addition to substantial working inventories and working capital associated with its merchant activities, the marketing segment also employs significant volumes of crude oil and LPG as linefill or minimum inventory requirements under service arrangements with transportation carriers and terminalling providers. The marketing segment also employs trucks, trailers, barges, railcars and leased storage.

As of December 31, 2006, the marketing segment owned crude oil and LPG classified as long-term assets and a variety of owned or leased long-term physical assets throughout the United States and Canada, including approximately:

- 7.9 million barrels of crude oil and LPG linefill in pipelines owned by the Partnership;
- 1.5 million barrels of crude oil and LPG linefill in pipelines owned by third parties;
- 500 trucks and 600 trailers; and
- 1,300 railcars.

In connection with its operations, the marketing segment secures transportation and facilities services from the Partnership’s other two segments as well as third-party service providers under month-to-month and multi-year arrangements. Inter-segment transportation service rates are based on posted tariffs for pipeline transportation services. Facilities segment services are also obtained at rates consistent with rates charged to third parties for similar services; however, certain terminalling and storage rates are discounted to our marketing segment to reflect the fact that these services may be canceled on short notice to enable the facilities segment to provide services to third parties.

Counter-Cyclical Balance

Access to storage tankage by our marketing segment provides a counter-cyclical balance that has a stabilizing effect on our operations and cash flow associated with this segment. The strategic use of our terminalling and storage assets in conjunction with our marketing operations generally provides us with the flexibility to maintain a base level of margin irrespective of crude oil market conditions and, in certain circumstances, to realize incremental margin during volatile market conditions. See "— Crude Oil Volatility; Counter-Cyclical Balance; Risk Management ."

Business Strategy

Our principal business strategy is to provide competitive and efficient midstream transportation, terminalling, storage and marketing services to our producer, refiner and other customers, and to address the regional supply and demand imbalances for crude oil, refined products and LPG that exist in the United States and Canada by combining the strategic location and distinctive capabilities of our transportation, terminalling and storage assets with our extensive marketing and distribution expertise. We believe successful execution of this strategy will enable us to generate sustainable earnings and cash flow. We intend to grow our business by:

- optimizing our existing assets and realizing cost efficiencies through operational improvements;
- developing and implementing internal growth projects that (i) address evolving crude oil, refined product and LPG needs in the midstream transportation and infrastructure sector and (ii) are well positioned to benefit from long-term industry trends and opportunities;
- utilizing our assets along the Gulf, West and East Coasts along with our Cushing Terminal and leased assets to increase our presence in the waterborne importation of foreign crude oil;
- establishing a presence in the refined product supply and marketing sector;
- selectively pursuing strategic and accretive acquisitions of crude oil, refined product and LPG transportation, terminalling, storage and marketing assets that complement our existing asset base and distribution capabilities; and
- using our terminalling and storage assets in conjunction with our marketing activities to address physical market imbalances, mitigate inherent risks and increase margin.

PAA/Vulcan's natural gas storage assets are also well-positioned to benefit from long-term industry trends and opportunities. Our natural gas storage growth strategies are to develop and implement internal growth projects and to selectively pursue strategic and accretive natural gas storage projects and facilities. We also intend to prudently and economically leverage our asset base, knowledge base and skill sets to participate in other energy-related businesses that have characteristics and opportunities similar to, or that otherwise complement, our existing activities.

Financial Strategy

Targeted Credit Profile

We believe that a major factor in our continued success is our ability to maintain a competitive cost of capital and access to the capital markets. We intend to maintain a credit profile that we believe is consistent with an investment grade credit rating. We have targeted a general credit profile with the following attributes:

- an average long-term debt-to-total capitalization ratio of approximately 50%;
- an average long-term debt-to-EBITDA multiple of approximately 3.5x or less (EBITDA is earnings before interest, taxes, depreciation and amortization); and
- an average EBITDA-to-interest coverage multiple of approximately 3.3x or better.

The first two of these three metrics include long-term debt as a critical measure. In certain market conditions, we also incur short-term debt in connection with marketing activities that involve the simultaneous purchase and forward sale of crude oil. The crude oil purchased in these transactions is hedged, is required to be stored on a month-to-month basis and is sold to high-credit quality counterparties. We do not consider the working capital borrowings associated with this activity to be part of our long-term capital structure. These borrowings are self-liquidating as they are repaid with sales proceeds following delivery of the crude oil. We also anticipate performing similar activities for refined products as we expand our presence in the refined products supply and marketing sector.

In order for us to maintain our targeted credit profile and achieve growth through internal growth projects and acquisitions, we intend to fund at least 50% of the capital requirements associated with these activities with equity and cash flow in excess of distributions. From time to time, we may be outside the parameters of our targeted credit profile as, in certain cases, these capital expenditures and acquisitions may be financed initially using debt or there may be delays in realizing anticipated synergies from acquisitions or contributions to adjusted EBITDA from capital expansion projects. In this instance, "adjusted EBITDA" means earnings before interest, tax, depreciation, amortization, Long-Term Incentive Plan charges and gains and losses attributable to Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended ("SFAS 133"). At December 31, 2006, we were above our targeted parameter for the long-term debt-to-EBITDA ratio (due primarily to the closing of the Pacific acquisition in November 2006) and within the parameters of the other credit metrics. Based on our December 31, 2006 long-term debt balance and the midpoint of our adjusted EBITDA guidance for 2007 furnished in a Form 8-K dated February 22, 2007, our long-term debt-to-adjusted-EBITDA multiple would be 3.8.

Credit Rating

As of February 2007, our senior unsecured ratings with Standard & Poor's and Moody's Investment Services were BBB-negative outlook and Baa3 stable outlook, respectively, both of which are considered "investment grade." We have targeted the attainment of even stronger investment grade ratings of mid to high-BBB and Baa categories for Standard & Poor's and Moody's Investment Services, respectively. We cannot give assurance that our current ratings will remain in effect for any given period of time, that we will be able to attain the higher ratings we have targeted or that one or both of these ratings will not be lowered or withdrawn entirely by the ratings agency. Note that a credit rating is not a recommendation to buy, sell or hold securities, and may be revised or withdrawn at any time.

Competitive Strengths

We believe that the following competitive strengths position us successfully to execute our principal business strategy:

- ***Many of our transportation segment and facilities segment assets are strategically located and operationally flexible and have additional capacity or expansion capability.*** The majority of our primary transportation segment assets are in crude oil service, are located in well-established oil producing regions and transportation corridors, and are connected, directly or indirectly, with our facilities segment assets located at major trading locations and premium markets that serve as gateways to major North American refinery and distribution markets where we have strong business relationships.

- ***We possess specialized crude oil market knowledge.*** We believe our business relationships with participants in various phases of the crude oil distribution chain, from crude oil producers to refiners, as well as our own industry expertise, provide us with an extensive understanding of the North American physical crude oil markets.

- ***Our business activities are counter-cyclically balanced.*** We believe the balance of activities provided by our marketing segment provides us with a counter-cyclical balance that generally affords us the flexibility (i) to maintain a base level of margin irrespective of crude oil market conditions and (ii), in certain circumstances, to realize incremental margin during volatile market conditions.

- ***We have the evaluation, integration and engineering skill sets and the financial flexibility to continue to pursue acquisition and expansion opportunities.*** Over the past nine years, we have completed and integrated approximately 45 acquisitions with an aggregate purchase price of approximately $5.1 billion ($2.6 billion excluding the Pacific acquisition, for which we are still in the process of integrating). We have also implemented internal expansion capital projects totaling over $700 million. In addition, we believe we have significant resources to finance future strategic expansion and acquisition opportunities. As of December 31, 2006, we had approximately $1.3 billion available under our committed credit facilities, subject to continued covenant compliance. We believe we have one of the strongest capital structures relative to other master limited partnerships with capitalizations greater than $1.0 billion. In addition, the investors in our general partner are diverse and financially strong and have demonstrated their support by providing capital to help finance previous acquisitions and expansion activities. We believe they are supportive long-term sponsors of the partnership.

- ***We have an experienced management team whose interests are aligned with those of our unitholders.*** Our executive management team has an average of more than 20 years industry experience, with an average of more than 15 years with us or our predecessors and affiliates. Certain members of our senior management team own an approximate 5% interest in our general partner and collectively own approximately 850,000 common units, including fully vested options. In addition, through grants of phantom units, the senior management team also owns significant contingent equity incentives that generally vest upon achievement of performance objectives, continued service or both. These interests give management a vested interest in our continued success.

We believe many of these competitive strengths have similar application to our efforts to expand our presence in the refined products, LPG and natural gas storage sectors.

Organizational History

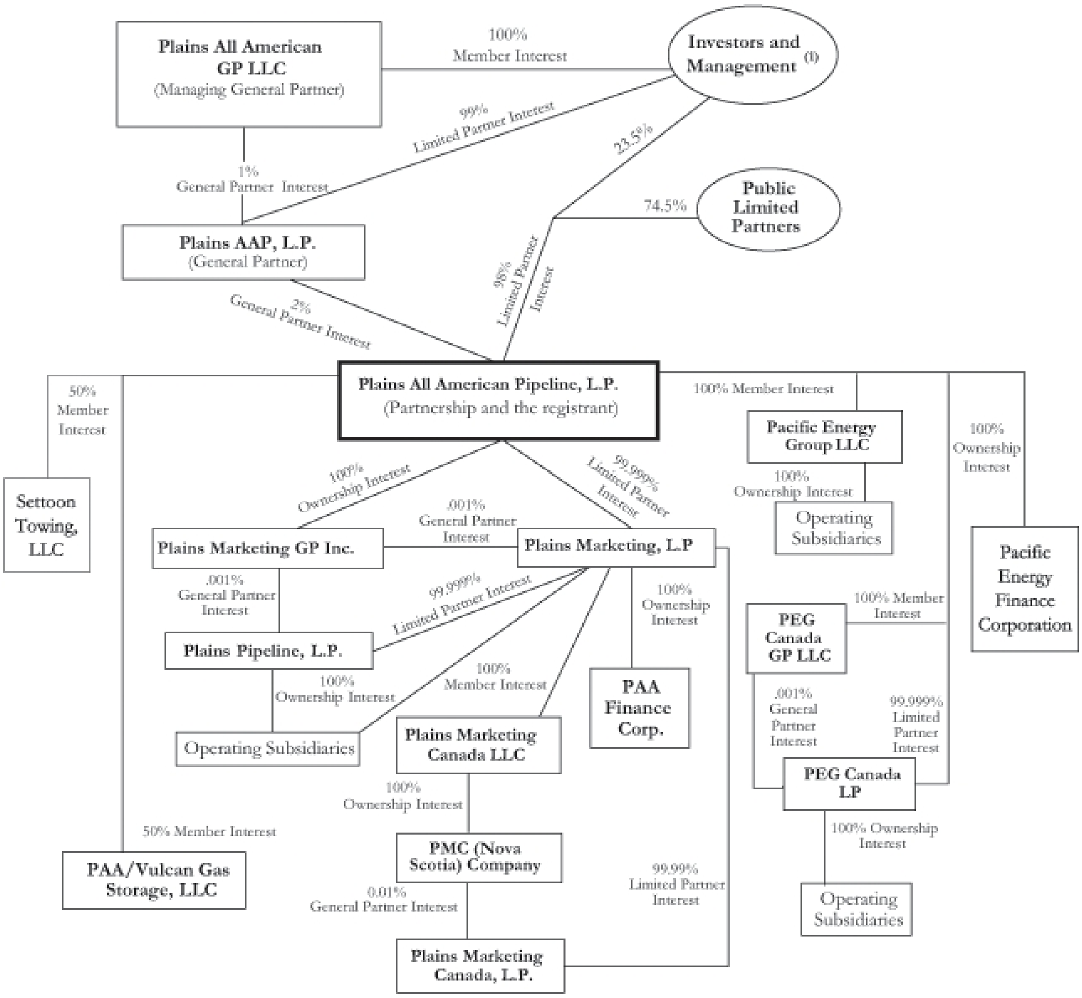
We were formed as a master limited partnership in September 1998 to acquire and operate the midstream crude oil businesses and assets of a predecessor entity. We completed our initial public offering in November 1998. Since June 2001, our 2% general partner interest has been held by Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P.'s general partner. Unless the context otherwise requires, we use the term "general partner" to refer to both Plains AAP, L.P. and Plains All American GP LLC. Plains AAP, L.P. and Plains All American GP LLC are essentially held by seven owners. See Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters — Beneficial Ownership of General Partner Interest."

Partnership Structure and Management

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. Our general partner, Plains AAP, L.P., is managed by its general partner, Plains All American GP LLC, which has ultimate responsibility for conducting our business and managing our operations. See Item 10. "Directors and Executive Officers of our General Partner and Corporate Governance." Our general partner does not receive a management fee or other compensation in connection with its management of our business, but it is reimbursed for substantially all direct and indirect expenses incurred on our behalf.

The chart on the next page depicts the current structure and ownership of Plains All American Pipeline, L.P. and certain subsidiaries.

Partnership Structure



(1) Based on Form 4 filings for executive officers and directors, 13D filings for Paul G. Allen and Richard Kayne and other information believed to be reliable for the remaining investors, this group, or affiliates of such investors, owns approximately 26 million limited partner units, representing approximately 23.5% of the limited partner interest.

Acquisitions

The acquisition of assets and businesses that are strategic and complementary to our existing operations constitutes an integral component of our business strategy and growth objective. Such assets and businesses include crude oil related assets, refined products assets and LPG assets, as well as other energy transportation related assets that have characteristics and opportunities similar to these business lines and enable us to leverage our asset base, knowledge base and skill sets. We have established a target to complete, on average, $200 million to $300 million in acquisitions per year, subject to availability of attractive assets on acceptable terms. Between 1998 and December 31, 2006, we have completed approximately 45 acquisitions for a cumulative purchase price of approximately $5.1 billion.

Table of Contents

The following table summarizes acquisitions greater than $50 million that we have completed over the past five years:

Acquisition	Date	Description	Approximate Purchase Price (In millions)
Pacific Energy Partners LP	November 2006	Merger of Pacific Energy Partners with and into the Partnership	$ 2,456
Products Pipeline System	September 2006	Three refined products pipeline systems	$ 66
Crude Oil Systems	July 2006	64.35% interest in the Clovelly-to-Meraux Pipeline system; 100% interest in the Bay Marchand-to-Ostrica-to-Alliance system and various interests in the High Island Pipeline System (2)	$ 130
Andrews Petroleum and Lone Star Trucking	April 2006	Isomerization, fractionation, marketing and transportation services	$ 220
South Louisiana Gathering and Transportation Assets (SemCrude)	April 2006	Crude oil gathering and transportation assets, including inventory, and related contracts in South Louisiana	$ 129
Investment in Natural Gas Storage Facilities	September 2005	Joint venture with Vulcan Gas Storage LLC to develop and operate natural gas storage facilities.	$ 125 (1)
Link Energy LLC	April 2004	The North American crude oil and pipeline operations of Link Energy, LLC (''Link")	$ 332
Capline and Capwood Pipeline Systems	March 2004	An approximate 22% undivided joint interest in the Capline Pipeline System and an approximate 76% undivided joint interest in the Capwood Pipeline System	$ 159
Shell West Texas Assets	August 2002	Basin Pipeline System, Permian Basin Pipeline System and the Rancho Pipeline System	$ 324

(1) Represents 50% of the purchase price for the acquisition made by our joint venture. The joint venture completed an acquisition for approximately $250 million during 2005.

(2) Our interest in the High Island Pipeline System was relinquished in November 2006.

Pacific Energy Acquisition

On November 15, 2006 we completed our acquisition of Pacific pursuant to an Agreement and Plan of Merger dated June 11, 2006. The merger-related transactions included: (i) the acquisition from LB Pacific, LP and its affiliates ("LB Pacific") of the general partner interest and incentive distribution rights of Pacific as well as approximately 5.2 million Pacific common units and approximately 5.2 million Pacific subordinated units for a total of $700 million and (ii) the acquisition of the balance of Pacific's equity through a unit-for-unit exchange in which each Pacific unitholder (other than LB Pacific) received 0.77 newly issued Partnership common units for each

Pacific common unit. The total value of the transaction was approximately $2.5 billion, including the assumption of debt and estimated transaction costs. Upon completion of the merger-related transactions, the general partner and limited partner ownership interests in Pacific were extinguished and Pacific was merged with and into the Partnership. The assets acquired in the Pacific acquisition included approximately 4,500 miles of active crude oil pipeline and gathering systems and 550 miles of refined products pipelines, over 13 million barrels of active crude oil and 9 million barrels of refined products storage capacity, a fleet of approximately 75 owned or leased trucks and approximately 1.9 million barrels of crude oil and refined products linefill and working inventory. The Pacific assets complement our existing asset base in California, the Rocky Mountains and Canada, with minimal asset overlap but attractive potential vertical integration opportunities. The results of operations and assets and liabilities from this acquisition (the "Pacific acquisition") have been included in our consolidated financial statements since November 15, 2006. The purchase price allocation related to the Pacific acquisition is preliminary and subject to change. See Note 3 to our Consolidated Financial Statements.

Other 2006 Acquisitions

During 2006, we completed six additional acquisitions for aggregate consideration of approximately $565 million. These acquisitions included (i) 100% of the equity interests of Andrews Petroleum and Lone Star Trucking, which provide isomerization, fractionation, marketing and transportation services to producers and customers of natural gas liquids (collectively, the "Andrews acquisition"), (ii) crude oil gathering and transportation assets and related contracts in South Louisiana ("SemCrude"), (iii) interests in various crude oil pipeline systems in Canada and the U.S. including a 100% interest in the Bay Marchand-to-Ostrica-to-Alliance ("BOA") Pipeline, various interests in the High Island Pipeline System ("HIPS"), and a 64.35% interest in the Clovelly-to-Meraux ("CAM") Pipeline system, and (iv) three refined products pipeline systems from Chevron Pipe Line Company.

Ongoing Acquisition Activities

Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase by us of assets and operations that are strategic and complementary to our existing operations. Such assets and operations include crude oil related assets, refined products assets, LPG assets and, through our interest in PAA/Vulcan, natural gas storage assets. In addition, we have in the past and intend in the future to evaluate and pursue other energy related assets that have characteristics and opportunities similar to these business lines and enable us to leverage our asset base, knowledge base and skill sets. Such acquisition efforts may involve participation by us in processes that have been made public and involve a number of potential buyers, commonly referred to as "auction" processes, as well as situations in which we believe we are the only party or one of a limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets which, if acquired, could have a material effect on our financial condition and results of operations.

Crude Oil Market Overview

Our assets and our business strategy are designed to service our producer and refiner customers by addressing regional crude oil supply and demand imbalances that exist in the United States and Canada. According to the Energy Information Administration ("EIA"), during the twelve months ended October 2006, the United States consumed approximately 15.2 million barrels of crude oil per day, while only producing 5.1 million barrels per day. Accordingly, the United States relies on foreign imports for nearly 66% of the crude oil used by U.S. domestic refineries. This imbalance represents a continuing trend. Foreign imports of crude oil into the U.S. have tripled over the last 21 years, increasing from 3.2 million barrels per day in 1985 to 10.2 million barrels per day for the 12 months ended October 2006, as U.S. refinery demand has increased and domestic crude oil production has declined due to natural depletion.

The Department of Energy segregates the United States into five Petroleum Administration Defense Districts ("PADDs") which are used by the energy industry for reporting statistics regarding crude oil supply and demand. The table below sets forth supply, demand and shortfall information for each PADD for the twelve months ended October 2006 and is derived from information published by the EIA (see EIA website at www.eia.doe.gov).

Petroleum Administration Defense District	Supply	Refinery Demand	Supply Shortfall
	(Millions of barrels per day)		
PADD I (East Coast)	0.0	1.5	(1.5)
PADD II (Midwest)	0.5	3.3	(2.8)
PADD III (South)	2.8	7.2	(4.4)
PADD IV (Rockies)	0.3	0.5	(0.2)
PADD V (West Coast)	1.5	2.7	(1.2)
Total U.S.	5.1	15.2	(10.1)

Although PADD III has the largest supply shortfall, PADD II is believed to be the most critical region with respect to supply and transportation logistics because it is the largest, most highly populated area of the U.S. that does not have direct access to oceanborne cargoes.

Over the last 21 years, crude oil production in PADD II has declined from approximately 1.0 million barrels per day to approximately 450,000 barrels per day. Over this same time period, refinery demand has increased from approximately 2.7 million barrels per day in 1985 to 3.3 million barrels per day for the twelve months ended October 2006. As a result, the volume of crude oil transported into PADD II has increased 71%, from 1.7 million barrels per day to 2.9 million barrels per day. This aggregate shortfall is principally supplied by direct imports from Canada to the north and from the Gulf Coast area and the Cushing Interchange to the south.

The logistical transportation, terminalling and storage challenges associated with regional volumetric supply and demand imbalances are further complicated by the fact that crude oil from different sources is not fungible. The crude slate available to U.S. refineries consists of a substantial number of different grades and varieties of crude oil. Each crude grade has distinguishing physical properties, such as specific gravity (generally referred to as light or heavy), sulfur content (generally referred to as sweet or sour) and metals content as well as varying economic attributes. In many cases, these factors result in the need for such grades to be batched or segregated in the transportation and storage processes, blended to precise specifications or adjusted in value. In addition, from time to time, natural disasters and geopolitical factors, such as hurricanes, earthquakes, tsunamis, inclement weather, labor strikes, refinery disruptions, embargoes and armed conflicts, may impact supply, demand and transportation and storage logistics.

Refined Products Market Overview

Once crude oil is transported to a refinery, it is broken down into different petroleum products. These “refined products” fall into three major categories: fuels such as motor gasoline and distillate fuel oil (diesel fuel); finished non-fuel products such as solvents and lubricating oils; and feedstocks for the petrochemical industry such as naphtha and various refinery gases. Demand is greatest for products in the fuels category, particularly motor gasoline.

The characteristics of the gasoline produced depend upon the setup of the refinery at which it is produced and the type of crude oil that is used. Gasoline characteristics are also impacted by other ingredients that may be blended into it, such as ethanol. The performance of the gasoline must meet industry standards and environmental regulations that vary based on location.

After crude oil is refined into gasoline and other petroleum products, the products must be distributed to consumers. The majority of products are shipped by pipeline to storage terminals near consuming areas, and then loaded into trucks for delivery to gasoline stations or other end users. Some of the products which are used as feedstocks are typically transported by pipeline to chemical plants.

Demand for refined products is increasing and is affected by price levels, economic growth trends and, to a lesser extent, weather conditions. According to the EIA, consumption of refined products in the United States has risen steadily from approximately 15.7 million barrels per day in 1985 to approximately 20.7 million barrels per day for the twelve months ended October 2006, an increase of 31%. By 2030, the EIA estimates that the U.S. will consume approximately 27.6 million barrels per day of refined products, an increase of 33% over the last twelve months' levels. We believe that the additional demand will be met by growth in the capacity of existing refineries through large expansion projects and "capacity creep" as well as increased imports of refined products, both of which we believe will generate incremental demand for midstream infrastructure, such as pipelines and terminals.

We believe that demand for refined products pipeline and terminalling infrastructure will also increase as a result of:

- multiple specifications of existing products (also referred to as boutique gasoline blends);
- specification changes to existing products, such as ultra low sulfur diesel;
- new products, such as bio-fuels;
- the aging of existing infrastructure; and
- the potential reduction in storage capacity due to regulations governing the inspection, repair, alteration and construction of storage tanks.

We intend to grow our asset base in the refined products business through expansion projects and future acquisitions. Consistent with our plan to apply our proven business model to these assets, we also intend to optimize the value of our refined products assets and better serve the needs of our customers by building a complementary refined products supply and marketing business.

LPG Products Market Overview

LPGs are a group of hydrogen-based gases that are derived from crude oil refining and natural gas processing. They include ethane, propane, normal butane, isobutane and other related products. For transportation purposes, these gases are liquefied through pressurization. LPG is also imported into the U.S. from Canada and other parts of the world.

LPGs are principally used as feedstock for petrochemical production processes. Individual LPG products have specific uses. For example, propane is used for home heating, water heating, cooking, crop drying and tobacco curing. As a motor fuel, propane is burned in internal combustion engines that power over-the-road vehicles, forklifts and stationary engines. Ethane is used primarily as a petrochemical feedstock. Normal butane is used as a petrochemical feedstock, as a blend stock for motor gasoline, and to derive isobutane through isomerization. Isobutane is principally used in refinery alkylation to enhance the octane content of motor gasoline or in the production of isooctane or other octane additives. Certain LPGs are also used as diluent in the transportation of heavy oil, particularly in Canada.

According to the EIA, consumption of LPGs in the United States has risen steadily from approximately 1.6 million barrels per day in 1985 to approximately 2.1 million barrels per day for the twelve months ended October 2006, an increase of 33%. By 2030, the EIA estimates that the U.S. will consume approximately 2.4 million barrels per day of LPGs, an increase of 13% over the last twelve months' levels. We believe that the additional demand will result in an increased demand for LPG infrastructure, including pipelines, storage facilities, processing facilities and import terminals.

We intend to grow our asset base in the LPG business through expansion projects and future acquisitions. We believe that our asset base, which is principally located in the upper tier of the U.S., Oklahoma and California, provides flexibility in meeting the needs of our customers and opportunities to capitalize on regional supply/demand imbalances in LPG markets.

Natural Gas Storage Market Overview

After treatment for impurities such as carbon dioxide and hydrogen sulfide and processing to separate heavier hydrocarbons from the gas stream, natural gas from one source generally is fungible with natural gas from any other source. Because of its fungibility and physical volatility and the fact that it is transported in a gaseous state, natural gas presents different logistical transportation challenges than crude oil and refined products; however, we believe the U.S. natural gas supply and demand situation will ultimately face storage challenges very similar to those that exist in the North American crude oil sector. We believe these factors will result in an increased need and an attractive valuation for natural gas storage facilities in order to balance market demands. From 1990 to 2005, domestic natural gas production grew approximately 2% while domestic natural gas consumption rose approximately 15%, resulting in an approximate 175% increase in the domestic supply shortfall over that time period. In addition, significant excess domestic production capacity contractually withheld from the market by take-or-pay contracts between natural gas producers and purchasers in the late 1980s and early 1990s has since been eliminated. This trend of an increasing domestic supply shortfall is expected to continue. By 2030, the EIA estimates that the U.S. will require approximately 5.5 trillion cubic feet of annual net natural gas imports (or approximately 15 billion cubic feet per day) to meet its demand, nearly 1.4 times the 2005 annual shortfall.

The vast majority of the projected supply shortfall is expected to be met with imports of liquefied natural gas (LNG). According to the Federal Energy Regulatory Commission ("FERC") as of January 2007, plans for 34 new LNG terminals in the United States and Bahamas have been proposed, 17 of which are to be situated along the Gulf Coast. Of the 17 proposed Gulf Coast facilities, three are under construction, nine have been approved by the appropriate regulatory agencies, and five have been proposed to the appropriate regulatory agencies. These facilities will be used to re-gasify the LNG prior to shipment in pipelines to natural gas markets.

Normal depletion of regional natural gas supplies will require additional storage capacity to pre-position natural gas supplies for seasonal usage. In addition, we believe that the growth of LNG as a supply source will also increase the demand for natural gas storage as a result of inconsistent surges and shortfalls in supply based on LNG tanker deliveries, similar in many respects to the issues associated with waterborne crude oil imports. LNG shipments are exposed to a number of risks related to natural disasters and geopolitical factors, including hurricanes, earthquakes, tsunamis, inclement weather, labor strikes and facility disruptions, which can impact supply, demand and transportation and storage logistics. These factors are in addition to the already dramatic impact of seasonality and regional weather issues on natural gas markets.

Description of Segments and Associated Assets

Our business activities are conducted through three segments — Transportation, Facilities and Marketing. We have an extensive network of transportation, terminalling and storage facilities at major market hubs and in key oil producing basins and crude oil, refined product and LPG transportation corridors in the United States and Canada.

Following is a description of the activities and assets for each of our business segments.

Transportation

Our transportation segment operations generally consist of fee-based activities associated with transporting volumes of crude oil and refined products on pipelines and gathering systems.

As of December 31, 2006, we employed a variety of owned or leased long-term physical assets throughout the United States and Canada in this segment, including approximately:

- 20,000 miles of active pipelines and gathering systems;
- 30 million barrels of tank capacity used primarily to facilitate pipeline movements; and
- 57 transport and storage barges and 30 transport tugs through our 50% interest in Settoon Towing.

We generate revenue through a combination of tariffs, third party leases of pipeline capacity, transportation fees, barrel exchanges and buy/sell arrangements. We also include in this segment our equity earnings from our investments in the Butte and Frontier pipeline systems, in which we own minority interests, and Settoon Towing, in which we own a 50% interest.

Substantially all of our pipeline systems are controlled or monitored from one of four central control rooms with computer systems designed to continuously monitor real-time operational data, such as measurement of crude oil quantities injected into and delivered through the pipelines, product flow rates, and pressure and temperature variations. The systems are designed to enhance leak detection capabilities, sound automatic alarms in the event of operational conditions outside of pre-established parameters and provide for remote controlled shut-down of the majority of our pump stations on the pipeline systems. Pump stations, storage facilities and meter measurement points along the pipeline systems are linked by satellite, radio, fiber optic cable, telephone, or a combination thereof to provide communications for remote monitoring and in some instances operational control, which reduces our requirement for full-time site personnel at most of these locations.

We make repairs on and replacements of our mainline pipeline systems when necessary or appropriate. We attempt to control corrosion of the mainlines through the use of cathodic protection, corrosion inhibiting chemicals injected into the crude and refined product streams and other protection systems typically used in the industry. Maintenance facilities containing spare parts and equipment for pipe repairs, as well as trained response personnel, are strategically located along the pipelines and in concentrated operating areas. We believe that all of our pipelines have been constructed and are maintained in all material respects in accordance with applicable federal, state, provincial and local laws and regulations, standards prescribed by the American Petroleum Institute ("API"), the Canadian Standards Association and accepted industry practice as required or considered appropriate under the circumstances. See "— Regulation — Pipeline and Storage Regulation."

Following is a tabular presentation of all of our active pipeline assets in the United States and Canada, grouped by geographic location:

Region	Pipeline/Gathering Systems	% Ownership	System Miles	2006 Average Net Barrels per Day(1)
Southwest US	Basin	87%	519	332,000
	Dollarhide	100%	24	5,000
	El Paso — Albuquerque (refined products)	100%	257	28,000
	Garden City	100%	63	10,000
	Hardeman	100%	107	4,000
	Iatan	100%	360	21,000
	Iraan	100%	98	31,000
	Merkel	100%	128	4,000
	Mesa	63%	80	31,000
	New Mexico	100%	1,163	81,000
	Permian Basin Gathering	100%	780	59,000
	Spraberry Gathering	100%	727	42,000
	Texas	100%	1,498	75,000
	West Texas Gathering	100%	738	85,000
Western US	All American	100%	136	49,000
	Line 63	100%	323	86,000
	Line 2000	100%	151	73,000
	San Joaquin Valley	100%	77	88,000
US Rocky Mountain	AREPI	100%	42	46,000
	Beartooth	50%	76	15,000
	Bighorn	58%	336	15,000
	Butte(3)	22%	370	18,000
	Frontier	22%	290	46,000
	Glacier(3)	21%	614	20,000
	North Dakota/Trenton	100%	731	89,000
	Rocky Mountain Gathering	100%	400	27,000
	Rocky Mountain Products (refined products)	100%	554	61,000
	Salt Lake City Core	100%	960	45,000
US Gulf Coast	ArkLaTex	100%	87	21,000
	Atchafalaya	100%	35	20,000

Table of Contents

Region	Pipeline/Gathering Systems	% Ownership	System Miles	2006 Average Net Barrels per Day(1)
	BOA	100%	107	82,000
	Bridger Lakes	100%	19	1,000
	CAM (Segment I/Segment II)	60%/0%	47	131,000
	Capline(3)	22%	633	160,000
	Capwood/Patoka	76%	58	99,000
	Cocodrie	100%	66	6,000
	East Texas	100%	9	8,000
	Eugene Island	100%	66	11,000
	Golden Meadow	100%	37	3,000
	Deleck	100%	119	29,000
	Mississippi/Alabama	100%	837	87,000
	Pearsall	100%	62	2,000
	Red River	100%	359	13,000
	Red Rock	100%	54	3,000
	Sabine Pass	100%	33	12,000
	Southwest Louisiana	100%	205	4,000
	Turtle Bayou	100%	14	3,000
Central US	Cushing to Broome	100%	103	73,000
	Midcontinent	100%	1,197	35,000
	Oklahoma	100%	1,629	59,000
	Domestic Total		17,378	2,348,000
Canada	Cactus Lake(2)	100%	115	16,000
	Cal Ven	100%	148	16,000
	Joarcam	100%	31	4,000
	Manito	100%	381	61,000
	Milk River	100%	33	96,000
	Rangeland	100%	938	66,000
	South Saskatchewan	100%	344	47,000
	Wapella	100%	73	11,000
	Wascana	100%	107	3,000
	Canada Total		2,170	320,000
	Total		19,548	2,668,000

(1) Represents average volumes for the entire year of 2006.

(2) For January through March 2006, our interest was 15%; we acquired the remaining interest in March 2006.

(3) Non-operated pipeline.

Below is a detailed description of our more significant transportation segment assets.

Major Transportation Assets

All American Pipeline System

The All American Pipeline is a common-carrier crude oil pipeline system that transports crude oil produced from certain outer continental shelf, or OCS, fields offshore California via connecting pipelines to refinery markets in California. The system extends approximately 10 miles along the California coast from Las Flores to Gaviota (24-inch diameter pipe) and continues from Gaviota approximately 126 miles to our station in Emidio, California (30-inch diameter pipe). Between Gaviota and our Emidio Station, the All American Pipeline interconnects with our San Joaquin Valley (or SJV) Gathering System, Line 2000 and Line 63, as well as other third party intrastate pipelines. The system is subject to tariff rates regulated by the FERC.

The All American Pipeline currently transports OCS crude oil received at the onshore facilities of the Santa Ynez field at Las Flores and the onshore facilities of the Point Arguello field located at Gaviota. ExxonMobil, which owns all of the Santa Ynez production, and Plains Exploration and Production Company and other producers that together own approximately 70% of the Point Arguello production, have entered into transportation agreements committing to transport all of their production from these fields on the All American Pipeline. These agreements provide for a minimum tariff with annual escalations based on specific composite indices. The producers from the Point Arguello field that do not have contracts with us have no other existing means of transporting their production and, therefore, ship their volumes on the All American Pipeline at the filed tariffs. For 2006 and 2005, tariffs on the All American Pipeline averaged $2.07 per barrel and $1.87 per barrel, respectively. The agreements do not require these owners to transport a minimum volume. These agreements, which had an initial term expiring in August 2007, include an annual one year evergreen provision that requires one year's advance notice to cancel.

With the acquisition of Line 2000 and Line 63, a significant portion of our transportation segment profit is derived from the pipeline transportation business associated with the Santa Ynez and Point Arguello fields and fields located in the San Joaquin Valley. We estimate that a 5,000 barrel per day decline in volumes shipped from the outer continental shelf fields would result in a decrease in annual transportation segment profit of approximately $6.1 million. A similar decline in volumes shipped from the San Joaquin Valley would result in an estimated $3.2 million decrease in annual transportation segment profit.

The table below sets forth the historical volumes received from both of these fields for the past five years:

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(Barrels in thousands)				
Average daily volumes received from:					
Point Arguello (at Gaviota)	9	10	10	13	16
Santa Ynez (at Las Flores)	40	41	44	46	50
Total	49	51	54	59	66

Basin Pipeline System

We own an approximate 87% undivided joint interest in and act as operator of the Basin Pipeline System. The Basin system is a primary route for transporting Permian Basin crude oil to Cushing, Oklahoma, for further delivery to Mid-Continent and Midwest refining centers. The Basin system is a 519-mile mainline, telescoping crude oil system with a capacity ranging from approximately 144,000 barrels per day to 400,000 barrels per day depending on the segment. System throughput (as measured by system deliveries) was approximately 332,000 barrels per day (net to our interest) during 2006. Within the current operating range, a 20,000 barrel per day decline in volumes shipped on the Basin system would result in a decrease in annual transportation segment profit of approximately $1.8 million.

The Basin system consists of four primary movements of crude oil: (i) barrels that are shipped from Jal, New Mexico to the West Texas markets of Wink and Midland; (ii) barrels that are shipped from Midland to connecting carriers at Colorado City; (iii) barrels that are shipped from Midland and Colorado City to connecting carriers at either Wichita Falls or Cushing; and (iv) foreign and Gulf of Mexico barrels that are delivered into Basin at Wichita Falls and delivered to connecting carriers at Cushing. The system also includes approximately 5.5 million barrels (4.8 million barrels, net to our interest) of crude oil storage capacity located along the system. In 2004, we expanded an approximate 425-mile section of the system from Midland to Cushing. With the completion of this expansion, the capacity of this section has increased approximately 15%, from 350,000 barrels per day to approximately 400,000 barrels per day. The Basin system is subject to tariff rates regulated by the FERC.

Capline/Capwood Pipeline Systems

The Capline Pipeline System, in which we own a 22% undivided joint interest, is a 633-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capline Pipeline System is one of the primary transportation routes for crude oil shipped into the Midwestern U.S., accessing over 2.7 million barrels of refining capacity in PADD II. Shell is the operator of this system. Capline has direct connections to a significant amount of crude production in the Gulf of Mexico. In addition, with its two active docks capable of handling 600,000-barrel tankers as well as access to the Louisiana Offshore Oil Port, it is a key transporter of sweet and light sour foreign crude to PADD II. With a total system operating capacity of 1.14 million barrels per day of crude oil, approximately 248,000 barrels per day are subject to our interest. During 2006, throughput on our interest averaged approximately 160,000 barrels per day. A 10,000 barrel per day decline in volumes shipped on the Capline system would result in a decrease in our annual transportation segment profit of approximately $1.3 million.

The Capwood Pipeline System, in which we own a 76% undivided joint interest, is a 58-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois. The Capwood Pipeline System has an operating capacity of 277,000 barrels per day of crude oil. Of that capacity, approximately 211,000 barrels per day are subject to our interest. The system has the ability to deliver crude oil at Wood River to several other PADD II refineries and pipelines. Movements on the Capwood system are driven by the volumes shipped on Capline as well as by volumes of Canadian crude that can be delivered to Patoka via the Mustang Pipeline. PAA assumed the operatorship of the Capwood system from Shell Pipeline Company LP at the time of purchase. During 2006 throughput net to our interest averaged approximately 99,000 barrels per day.

Line 2000

We own and operate Line 2000, an intrastate common carrier crude oil pipeline that originates at our Emidio Pump Station and transports crude oil produced in the San Joaquin Valley and California outer continental shelf to refineries and terminal facilities in the Los Angeles Basin. Line 2000 is a 151-mile trunk pipeline with a throughput capacity of 130,000 barrels per day. For the full year of 2006, throughput on Line 2000 averaged approximately 73,000 barrels per day.

Line 63

The Line 63 system is an intrastate common carrier crude oil pipeline system that transports crude oil produced in the San Joaquin Valley and California outer continental shelf to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. The Line 63 system consists of a 107-mile trunk pipeline, originating at our Kelley Pump Station in Kern County, California and terminating at our West Hynes Station in Long Beach, California. The Line 63 system includes 60 miles of distribution pipelines in the Los Angeles Basin and in the Bakersfield area, 156 miles of gathering pipelines in the San Joaquin Valley, and 22 storage tanks with approximately 1.2 million barrels of storage capacity. These storage assets, the majority of which are located in the San Joaquin Valley, are used primarily to facilitate the transportation of crude oil on the Line 63 system. Line 63 has a throughput capacity of approximately 105,000 barrels per day. For the full year of 2006, throughput on Line 63 averaged approximately 86,000 barrels per day.

Rangeland System

The Rangeland system includes the Mid Alberta Pipeline and the Rangeland Pipeline. The Mid Alberta Pipeline is a 138-mile proprietary pipeline with a throughput capacity of approximately 50,000 barrels per day if transporting light crude oil. The Mid Alberta Pipeline originates in Edmonton, Alberta and terminates in Sundre, Alberta where it connects to the Rangeland Pipeline. The Rangeland Pipeline is a proprietary pipeline system that consists of approximately 800 miles of gathering and trunk pipelines and is capable of transporting crude oil, condensate and butane either north to Edmonton, Alberta via third-party pipeline connections or south to the U.S./Canadian border near Cutbank, Montana where it connects to our Western Corridor system. The trunk pipeline from Sundre, Alberta to the U.S./Canadian border consists of approximately 250 miles of trunk pipelines and has a current throughput capacity of approximately 85,000 barrels per day if transporting light crude oil. The trunk system from Sundre, Alberta north to Rimbey, Alberta is a bi-directional system that consists of three parallel trunk pipelines: a 56-mile pipeline for low sulfur crude oil, a 63-mile pipeline for high sulfur crude oil, and a 56-mile pipeline for condensate and butane. From Rimbey, third-party pipelines move product north to Edmonton. For the full year of 2006, 22,500 barrels per day of crude oil was transported on the segment of the pipeline from Sundre north to Edmonton and 43,500 barrels per day was transported on the pipeline from Sundre south to the United States.

Western Corridor System

The Western Corridor system is an interstate and intrastate common carrier crude oil pipeline system that consists of 1,012 miles of pipelines extending from the U.S./Canadian border near Cutbank, Montana, where it receives deliveries from our Rangeland Pipeline and the Cenex Pipeline, and terminates at Guernsey, Wyoming with connections to our Salt Lake City Core system, the Frontier Pipeline and various third-party pipelines. The Western Corridor system consists of three contiguous trunk pipelines: Glacier Pipeline, Beartooth Pipeline and Big Horn Pipeline.

- *Glacier Pipeline.* We own a 20.8% undivided interest in Glacier Pipeline, which provides us with approximately 25,000 barrels per day of throughput capacity. Glacier Pipeline consists of 614 miles of two parallel crude oil pipelines, a 277-mile, 12-inch trunk pipeline, a 288-mile, 8-inch and 10-inch trunk pipeline, and a 49-mile 12-inch loop line, all extending from the Canadian border and Cutbank, Montana to Billings, Montana. Shipments on Glacier Pipeline can be delivered either to refineries in Billings and Laurel, Montana or into our Beartooth pipeline. For the full year of 2006, our throughput on Glacier Pipeline was approximately 20,000 barrels per day. ConocoPhillips Pipe Line Company is the operator of the Glacier Pipeline.

- *Beartooth Pipeline.* We own a 50% undivided interest in Beartooth Pipeline, which provides us with approximately 25,000 barrels per day of throughput capacity. Beartooth Pipeline is a 76-mile, 12-inch trunk pipeline from Billings, Montana to Elk Basin, Wyoming. Beartooth Pipeline was constructed to connect our Glacier Pipeline with our Big Horn Pipeline where all shipments are delivered. For the full year of 2006, our throughput on Beartooth Pipeline was approximately 15,000 barrels per day. We operate the Beartooth Pipeline.

- *Big Horn Pipeline.* We own a 57.6% undivided interest in Big Horn Pipeline, which provides us with approximately 33,900 barrels per day of throughput capacity. Big Horn Pipeline consists of a 231-mile, 12-inch trunk pipeline from Elk Basin, Wyoming to Casper, Wyoming and a 105-mile, 12-inch trunk pipeline from Casper, Wyoming to Guernsey, Wyoming. Shipments on our Big Horn Pipeline can be delivered either to Wyoming refineries directly, into Frontier Pipeline at Casper, Wyoming or into the Salt Lake City Core system, the Suncor Pipeline, or Platte Pipeline at Guernsey, Wyoming. For the full year of 2006, our interest in throughput on Big Horn Pipeline was approximately 15,000 barrels per day. We operate the Big Horn Pipeline.

We also own various undivided interests in 22 storage tanks along the Western Corridor System that provide us with a total of approximately 1.3 million barrels of storage capacity.

Salt Lake City Core System

We own and operate the Salt Lake City Core system, an interstate and intrastate common carrier crude oil pipeline system that transports crude oil produced in Canada and the U.S. Rocky Mountain region primarily to refiners in Salt Lake City. The Salt Lake City Core system consists of 960 miles of trunk pipelines with a combined throughput capacity of approximately 114,000 barrels per day to Salt Lake City, 209 miles of gathering pipelines, and 32 storage tanks with a total of approximately 1.4 million barrels of storage capacity. This system originates in Ft. Laramie, Wyoming, receives deliveries from the Western Corridor system at Guernsey, Wyoming and can deliver to Salt Lake City, Utah and Rangely, Colorado. For the full year of 2006, approximately 45,000 barrels per day were delivered to Salt Lake City directly through our pipelines and of this amount approximately 11,600 barrels per day were delivered indirectly through connections to a Chevron pipeline. We are constructing a 95-mile expansion of this system to Salt Lake City, which is scheduled to be completed in early 2008. When completed, the pipeline will have an estimated capacity of 120,000 barrels per day. The cost of this project is supported by 10-year transportation contracts that have been executed with four Salt Lake City refiners. Also, in February 2007, we signed a letter of intent to sell a 25% interest in this line to Holly Energy Partners, L.P. As part of this agreement, Holly Refining and Marketing will enter into a 10-year transportation agreement on terms consistent with the four previously committed refiners. Plains' portion of the total project cost is estimated to be $75 million, of which approximately $55 million is scheduled to be spent in 2007.

Cheyenne Pipeline

Pursuant to a transportation agreement, we are constructing a 16-inch crude oil pipeline, approximately 93 miles in length, from Fort Laramie to Cheyenne, Wyoming, in exchange for a ten-year firm commitment to ship 35,000 barrels per day on the new pipeline and lease approximately 300,000 barrels of storage capacity at Fort Laramie. The project also includes 10 miles of a 24-inch pipeline from Guernsey to Fort Laramie. The total project cost is estimated to be $59 million of which $34 million is the estimated remaining project cost to be incurred in 2007. The project is expected to be completed by the end of the second quarter of 2007. Initial capacity will be 55,000 barrels per day.

Rocky Mountain Products Pipeline System

The Rocky Mountain Products Pipeline System consists of a 554-mile refined products pipeline extending from Casper, Wyoming east to Rapid City, South Dakota and south to Colorado Springs, Colorado. The Rocky Mountain Products Pipeline originates near Casper, Wyoming, where it serves as a connecting point with Sinclair's Little America Refinery and the ConocoPhillips Seminole Pipeline, which transports product from Billings, Montana area refineries. The system continues to Douglas, Wyoming where it branches off to serve our Rapid City, South Dakota terminal approximately 190 miles away. This segment also receives product from Wyoming Refining Company via a third-party pipeline at a connection located near the border of Wyoming and South Dakota. From Douglas, Wyoming, the Rocky Mountain Products Pipeline continues south to our terminals at Cheyenne, Wyoming, where it receives refined products from a refinery via a third-party pipeline, and continues on to Denver, Colorado and Colorado Springs, Colorado. Our Denver terminal also receives refined products from Sinclair Pipeline. The various segments of the Rocky Mountain Products Pipeline have a combined throughput capacity of 85,000 barrels per day. For the full year of 2006, our throughput on the Rocky Mountain Products Pipeline System was approximately 61,000 barrels per day (average for the entire year). The Rocky Mountain Products Pipeline System includes products terminals at Rapid City, South Dakota, Cheyenne, Wyoming and Denver and Colorado Springs, Colorado with a combined storage capacity of 1.7 million barrels.

El Paso to Albuquerque System

The El Paso to Albuquerque refined products pipeline system is one of three refined products pipeline systems located in Texas and New Mexico. The El Paso to Albuquerque Products Pipeline system is a 257-mile system originating in El Paso, Texas, and terminating in Albuquerque, New Mexico, with approximately 28,200 barrels per day of throughput capacity. The El Paso to Albuquerque system receives various types of refined product at its origination station from Western Refining and Navajo Refining, and delivers product to third party terminals in Belen and Albuquerque, New Mexico. For the full year of 2006, our throughput on the El Paso to Albuquerque system was approximately 28,000 barrels per day.

Facilities

Our facilities segment generally consists of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products and LPG, as well as LPG fractionation and isomerization services.

As of December 31, 2006, we employed a variety of owned or leased long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 30 million barrels of active, above-ground terminalling and storage facilities;
- approximately 1.3 million barrels of active, underground terminalling and storage facilities; and
- two fractionation plants and one isomerization unit with aggregate processing capacity of 26,400 barrels per day.

At year-end 2006, the Partnership was in the process of constructing approximately 12.5 million barrels of additional above-ground terminalling and storage facilities, which we expect to place in service during 2007 and 2008.

Our facilities segment also includes our equity earnings from our investment in PAA/Vulcan. At December 31, 2006, PAA/Vulcan owned and operated approximately 25.7 billion cubic feet of underground storage capacity and was constructing an additional 24 billion cubic feet of underground storage capacity which is expected to be placed in service in stages over the next three years.

We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements. Revenues generated in this segment include (i) storage fees that are generated when we lease tank capacity and (ii) terminalling fees, or throughput fees, that are generated when we receive crude oil from one connecting pipeline and redeliver crude oil to another connecting carrier.

Following is a tabular presentation of our active facilities segment assets and those under construction in the United States and Canada, grouped by product type:

Facility	Facility Description	Capacity
Crude oil and refined products		
Cushing	Crude oil terminalling and storage facility at the Cushing Interchange	7.4 million barrels
Eastern	Refined products terminals in Philadelphia, Pennsylvania and Paulsboro, New Jersey	3.1 million barrels
Kerrobert	Crude oil terminalling and storage facility located near Kerrobert, Saskatchewan	1.7 million barrels
LA Basin	Crude oil and refined products storage and pipeline distribution system in Los Angeles Basin	9.0 million barrels
Martinez and Richmond	Crude oil and refined products storage terminals in the San Francisco area	4.5 million barrels
Mobile and Ten Mile	Crude oil marine and storage terminals in Mobile, Alabama	3.3 million barrels
St. James	Crude oil terminal in Louisiana (Phase I)	1.2 million barrels
LPG		
Alto	Butane and propane salt cavern storage terminal in Michigan	1.3 million barrels
Arlington and Washougal	Transloading LPG terminals in Washington	< 0.1 million barrels
Claremont	Transloading LPG terminal in New Hampshire	< 0.1 million barrels
Cordova	Transloading LPG terminal in Illinois	< 0.1 million barrels
Fort Madison	Propane pipeline terminal in Iowa	< 0.1 million barrels
High Prairie	Fractionation facility in Alberta, producing butane, propane and stabilized condensate	< 0.1 million barrels
Kincheloe	Transloading LPG terminal in Michigan	< 0.1 million barrels
Schaefferstown	Refrigerated storage terminal in Pennsylvania	0.5 million barrels

Facility	Facility Description	Capacity
Shafter	Isomerization facility in California, producing isobutane, propane and stabilized condensate	0.2 million barrels
Tulsa	Propane pipeline terminal in Oklahoma	< 0.1 million barrels
Natural Gas		
Bluewater/Kimball	Natural gas storage facility in Michigan	25.7 Bcf (1)
Under Construction		
Martinez	Expansion to crude oil and refined products terminal in California	0.9 million barrels
Mobile and Ten Mile	Expansion to crude oil terminal in Alabama	0.6 million barrels
Patoka	Crude oil storage and terminal facility in Patoka, Illinois	2.6 million barrels
Pier 400	Deepwater petroleum import terminal in the Port of Los Angeles	Under Development
Pine Prairie	Natural gas storage facility in Louisiana	24 Bcf (1)
Cushing	Expansion to crude oil terminalling and storage facility at the Cushing Interchange	3.4 million barrels
St. James	Expansion to crude oil terminal in Louisiana (Phase I and II)	5.0 million barrels

(1) Our interest in these facilities is 50% of the capacity stated above

Below is a detailed description of our more significant facilities segment assets.

Major Facilities Assets

Cushing Terminal

Our Cushing Terminal is located at the Cushing Interchange, one of the largest wet-barrel trading hubs in the U.S. and the delivery point for crude oil futures contracts traded on the NYMEX. The Cushing Terminal has been designated by the NYMEX as an approved delivery location for crude oil delivered under the NYMEX light sweet crude oil futures contract. As the NYMEX delivery point and a cash market hub, the Cushing Interchange serves as a primary source of refinery feedstock for the Midwest refiners and plays an integral role in establishing and maintaining markets for many varieties of foreign and domestic crude oil. Our Cushing Terminal was constructed in 1993, with an initial tankage capacity of 2 million barrels, to capitalize on the crude oil supply and demand imbalance in the Midwest. The facility was designed to handle multiple grades of crude oil while minimizing the interface and enable deliveries to connecting carriers at their maximum rate. The facility also incorporates numerous environmental and operations safeguards that distinguish it from all other facilities at the Cushing Interchange.

Since 1999, we have completed five separate expansion phases, which increased the capacity of the Cushing Terminal to a total of approximately 7.4 million barrels. The Cushing Terminal now consists of fourteen 100,000-barrel tanks, four 150,000-barrel tanks and twenty 270,000-barrel tanks, all of which are used to store and terminal crude oil. Our tankage ranges in age from one year to approximately 13 years with an average age of six years. In contrast, we estimate that the average age of the remaining tanks in Cushing owned by third parties is in excess of 40 years.

In September 2006, we announced our Phase VI expansion of our Cushing Terminal facility. Under the Phase VI expansion, we will construct approximately 3.4 million barrels of additional tankage. The Phase VI project will expand the total capacity of the facility to 10.8 million barrels and, including manifold modifications, is expected to cost approximately $48 million of which $27 million is the estimated remaining project cost to be incurred in 2007. We estimate that the new tankage will become operational during the fourth quarter of 2007. The expansion is supported by multi-year lease agreements.

Eastern Terminals

We own three refined product terminals in the Philadelphia, Pennsylvania area: a 0.9 million barrel terminal in North Philadelphia, a 0.6 million barrel terminal in South Philadelphia and a 1.6 million barrel terminal in Paulsboro, New Jersey. Our Philadelphia area terminals have 40 storage tanks with combined storage capacity of 3.1 million barrels. The terminals have 20 truck loading lanes, two barge docks and a ship dock. The Philadelphia area terminals provide services and products to all of the refiners in the Philadelphia harbor. The North Philadelphia and Paulsboro terminals have dock facilities that can load approximately 10,000 to 12,000 barrels per hour of refined products and black oils. The Philadelphia area terminals also receive products from connecting pipelines and offer truck loading services, barge cleaning and tug fuel services.

At our Philadelphia area terminals, we have completed an ethanol expansion project which enabled us to increase our ethanol handling and blending capabilities as well as increase our marine receipt capabilities. We plan to expand our Paulsboro facility by approximately 1.0 million barrels consisting of eight tanks ranging from 50,000 barrels to 150,000 barrels. This expansion is in the permitting stage and is scheduled to be completed in 2008 at an estimated cost of $31 million, of which approximately $20 million is scheduled to be spent in 2007.

Kerrobert

We own a crude oil and condensate storage and terminalling facility located near Kerrobert, Saskatchewan with a storage capacity of approximately 1.7 million barrels. The facility is connected to our Manito and Cactus Lake pipeline systems. In 2006, we increased the storage capacity at our Kerrobert facility by 900,000 barrels of tankage, bringing the total storage capacity to 1.7 million barrels. The cost of the expansion is estimated to be approximately $47 million, of which approximately $14 million is the estimated remaining project cost to be incurred in 2007.

Los Angeles Area Storage and Distribution System

We own four crude oil and refined product storage facilities in the Los Angeles area with a total of 9.0 million barrels of storage capacity and a distribution pipeline system of approximately 70 miles of pipeline in the Los Angeles Basin. The storage facility includes 34 storage tanks. Approximately 7.0 million barrels of the storage capacity are in active commercial service, 0.5 million barrels are used primarily for throughput to other storage tanks and do not generate revenue independently, approximately 1.2 million barrels are idle but could be reconditioned and brought into service and approximately 0.3 million barrels are in displacement oil service. We refurbished and placed in service 0.3 million barrels of black oil storage capacity in the third quarter of 2006 and expect to complete refurbishing an additional 0.3 million barrels of black oil storage in the first quarter of 2007. We are also making infrastructure changes to increase pumping capacity and improve operating efficiencies, which we expect to complete in 2007. We use the Los Angeles area storage and distribution system to service the storage and distribution needs of the refining, pipeline and marine terminal industries in the Los Angeles Basin. In addition, the Los Angeles area system has 17 storage tanks with a total of approximately 0.4 million barrels of storage capacity that are out of service. We are in the process of completing refurbishments and infrastructure changes at this facility. The Los Angeles area system's pipeline distribution assets connect its storage assets with major refineries, our Line 2000 pipeline, and third-party pipelines and marine terminals in the Los Angeles Basin. The system is capable of loading and off-loading marine shipments at a rate of 25,000 barrels per hour and transporting the product directly to or from certain refineries, other pipelines or its storage facilities. In addition, we can deliver crude oil and feedstocks from our storage facilities to the refineries served by this system at rates of up to 6,000 barrels per hour.

Martinez and Richmond Terminals

We own two terminals in the San Francisco, California area: a 3.9 million barrel terminal at Martinez (which provides refined product and crude oil service) and a 0.6 million barrel terminal at Richmond (which provides refined product service). Our San Francisco area terminals currently have 49 storage tanks with 4.5 million barrels of combined storage capacity that are connected to area refineries through a network of owned and third-party pipelines that carry crude oil and refined products to and from area refineries. The terminals have dock facilities that can load between approximately 4,000 and 10,000 barrels per hour of refined products. There is also a rail spur at the Richmond terminal that is able to receive products by train.

We recently added 450,000 barrels of storage capacity at the Martinez terminal and we are constructing an additional 850,000 barrels of storage capacity for completion in 2007 at a remaining estimated project cost of approximately $27 million.

Mobile and Ten Mile Terminal

We have a marine terminal in Mobile, Alabama (the "Mobile Terminal") that consists of eighteen tanks ranging in size from 10,000 barrels to 225,000 barrels, with current useable capacity of 1.5 million barrels. Approximately 1.8 million barrels of additional storage capacity is available at our nearby Ten Mile Facility through a 36" pipeline connecting the two facilities. In 2006, we started construction of a 600,000 barrel tank at the Ten Mile Facility. The cost for this tank is expected to be approximately $6.4 million of which $5.8 million is the estimated remaining project cost to be incurred in 2007. The new tank is expected to be in service in the second quarter of 2007.

The Mobile Terminal is equipped with a ship/tanker dock, barge dock, truck-unloading facilities and various third party connections for crude oil movements to area refiners. Additionally, the Mobile Terminal serves as a source for imports of foreign crude oil to PADD II refiners through our Mississippi/Alabama pipeline system, which connects to the Capline System at our station in Liberty, Mississippi.

St. James Terminal

In 2005, we began construction of a 3.5 million barrel crude oil terminal at the St. James crude oil interchange in Louisiana, which is one of the three most liquid crude oil interchanges in the United States. In the first phase of construction, we plan to build seven tanks ranging from 210,000 barrels to 670,000 barrels with an aggregate shell capacity of approximately 3.5 million barrels. At December 31, 2006, 1.2 million barrels of capacity were in service. The remaining capacity of Phase I is expected to be operational during the first quarter of 2007. The estimated total cost of Phase I is estimated to be approximately $105 million, of which $17.3 million is the estimated remaining project cost to be incurred in 2007. The facility will also include a manifold and header system that will allow for receipts and deliveries with connecting pipelines at their maximum operating capacity.

Under the Phase II project, we will construct approximately 2.7 million barrels of additional tankage at the facility. The Phase II project will expand the total capacity of the facility to 6.2 million barrels and is expected to cost approximately $64 million of which $43 million is the estimated project cost to be incurred in 2007. We estimate that the Phase II tankage will become operational during the first quarter of 2008.

Shafter

Our Shafter facility (acquired through the Andrews acquisition) provides isomerization and fractionation services to producers and customers of natural gas liquids ("NGLs") throughout the Western United States. The primary assets consist of 200,000 barrels of NGL storage, a processing facility with butane isomerization capacity of 14,000 barrels per day and NGL fractionation capacity of 9,600 barrels per day, and office facilities in California.

Patoka Terminal

In December 2006, we announced that we will build a 2.6 million barrel crude oil storage and terminal facility at the Patoka interchange in Patoka, Illinois. We anticipate that the new facility will become operational during the second half of 2008 for a total cost of approximately $77 million, including land costs. We expect to incur approximately half of the cost in 2007 and the remainder in 2008. Patoka is a growing regional hub with access to domestic and foreign crude oil volumes moving north on the Capline system as well as Canadian barrels moving south. This project will have the ability to be expanded should market conditions warrant.

Pier 400

We are in the process of developing a deepwater petroleum import terminal at Pier 400 and Terminal Island in the Port of Los Angeles to handle marine receipts of crude oil and refinery feedstocks. As currently envisioned, the project would include a deep water berth, high capacity transfer infrastructure and storage tanks, with a pipeline distribution system that will connect to various customers.

We have entered into agreements with ConocoPhillips and two subsidiaries of Valero Energy Corporation that provide long-term customer commitments to off-load a total of 140,000 bpd of crude oil at the Pier 400 dock. The ConocoPhillips and Valero agreements are subject to satisfaction of various conditions, such as the achievement of various progress milestones, financing, continued economic viability, and completion of other ancillary agreements related to the project. We are negotiating similar long-term off-loading agreements with other potential customers.

We have failed to meet certain project milestone dates set forth in our Valero agreements, and we are likely to miss other project milestones that are approaching under these agreements. Valero has not given any indication that it will seek to terminate such agreements. We expect that ongoing negotiations with Valero to extend the milestone dates will be successful and that the Valero agreements will remain in effect.

In January 2007, we completed an updated cost estimate for the project. We are estimating that Pier 400, when completed, will cost approximately $360 million, which is subject to change depending on various factors, including: (i) the final scope of the project and the requirements imposed through the permitting process and (ii) changes in construction costs. This cost estimate assumes the construction of 4.0 million barrels of storage. We are in the process of securing the environmental and other permits that will be required for the Pier 400 project from a variety of governmental agencies, including the Board of Harbor Commissioners, the South Coast Air Quality Management District, various agencies of the City of Los Angeles, the Los Angeles City Council and the U.S. Army Corps of Engineers. We expect to have the necessary permits in the first quarter of 2008. Final construction of the Pier 400 project is subject to the completion of a land lease (that will include a dock construction agreement) with the Port of Los Angeles, receipt of environmental and other approvals, securing additional customer commitments, updating engineering and project cost estimates, ongoing feasibility evaluation, and financing. Subject to timely receipt of approvals, we expect construction of the Pier 400 terminal may be completed and the facility placed in service in 2009 or 2010.

LPG Storage Facilities and Terminals

We own the following LPG storage facilities and terminals:

- Storage facilities with the capability of storing approximately 1.7 million barrels of product;
- Pipeline terminals consisting of (i) a 130-mile pipeline and terminal that is capable of storing 17,000 barrels of propane, and (ii) a facility that can store 7,000 barrels of propane where product is shipped out via truck; and
- Transloading facilities where product is delivered by rail car and shipped out via truck, with approximately 24,000 barrels of operational storage capacity.

We believe these facilities will further support the expansion of our LPG business in Canada and the U.S. as we combine the facilities' existing fee-based storage business with our wholesale propane marketing expertise. In addition, there may be opportunities to expand these facilities as LPG markets continue to develop in the region.

Natural Gas Storage Assets

We believe strategically located natural gas storage facilities with multi-cycle injection and withdrawal capabilities and access to critical transportation infrastructure will play an increasingly important role in balancing the markets and ensuring reliable delivery of natural gas to the customer during peak demand periods. We believe that our expertise in hydrocarbon storage, our strategically located assets, our financial strength and our commercial experience will enable us to play a meaningful role in meeting the challenges and capitalizing on the opportunities associated with the evolution of the U.S. natural gas storage markets.

Bluewater. The Bluewater gas storage facility, which is located in Michigan, is a depleted reservoir facility with an approximate 23 Bcf of capacity and is also strategically positioned. In April 2006, PAA/Vulcan acquired the Kimball gas storage facility and connected this 2.7 Bcf facility to the Bluewater facility. Natural gas storage facilities in the northern tier of the U.S. are traditionally used to meet seasonal demand and are typically cycled once or twice during a given year. Natural gas is injected during the summer months in order to provide for adequate deliverability during the peak demand winter months. Michigan is a very active market for natural gas storage as it meets nearly 75% of its peak winter demand from storage withdrawals. The Bluewater facility has direct interconnects to four major pipelines and has indirect access to another four pipelines as well as to Dawn, a major natural gas market hub in Canada.

Pine Prairie. The Pine Prairie facility is expected to become partially operational in 2007 and fully operational in 2009, and we believe it is well positioned to benefit from evolving market dynamics. The facility is located near Gulf Coast supply sources and near the existing Lake Charles LNG terminal, which is the largest LNG import facility in the United States. When completed, the Pine Prairie facility is expected to be a 24 Bcf salt cavern storage facility designed for high deliverability operating characteristics and multi-cycle capabilities. The initial phase of the facility will consist of three storage caverns with working capacity of eight Bcf per cavern and an extensive header system. Drilling operations on two of the three cavern wells is complete and drilling operations on the third cavern well commenced in late December 2006. Leaching operations on the first cavern well began in November 2006, construction of the gas handling and compression facilities began in December 2006 and construction on the pipeline interconnects began during January 2007. The site is located approximately 50 miles from the Henry Hub, the delivery point for NYMEX natural gas futures contracts, and is currently intended to interconnect with seven major pipelines serving the Midwest and the East Coast. Three additional pipelines are also located in the vicinity and offer the potential for future interconnects. We believe the facility's operating characteristics and strategic location position Pine Prairie to support the commercial functions of power generators, pipelines, utilities, energy merchants and LNG re-gasification terminal operators and provide potential customers with superior flexibility in managing their price and volumetric risk and balancing their natural gas requirements. In January 2007, an additional 240 acres of land were purchased adjacent to the Pine Prairie project to support future expansion activities.

Marketing

Our marketing segment operations generally consist of the following merchant activities:

- the purchase of U.S. and Canadian crude oil at the wellhead and the bulk purchase of crude oil at pipeline and terminal facilities, as well as the purchase of foreign cargoes at their load port and various other locations in transit;
- the storage of inventory during contango market conditions;
- the purchase of refined products and LPG from producers, refiners and other marketers;
- the resale or exchange of crude oil, refined products and LPG at various points along the distribution chain to refiners or other resellers to maximize profits; and
- arranging for the transportation of crude oil, refined products and LPG on trucks, barges, railcars, pipelines and ocean-going vessels to our terminals and third-party terminals.

Our marketing activities are designed to produce a stable baseline of results in a variety of market conditions, while at the same time providing upside exposure to opportunities inherent in volatile market conditions. These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies to reduce the negative impact of market volatility and provide counter-cyclical balance. The tankage that is used to support our arbitrage activities positions us to capture margins in a contango market (when the oil prices for future deliveries are higher than the current prices) or when the market switches from contango to backwardation (when the oil prices for future deliveries are lower than the current prices).

In addition to substantial working inventories and working capital associated with its merchant activities, the marketing segment also employs significant volumes of crude oil and LPG as linefill or minimum inventory requirements under service arrangements with transportation carriers and terminalling providers. The marketing segment also employs trucks, trailers, barges, railcars and leased storage.

As of December 31, 2006, the marketing segment owned crude oil and LPG classified as long-term assets and a variety of owned or leased long-term physical assets throughout the United States and Canada, including:

- 7.9 million barrels of crude oil and LPG linefill in pipelines owned by the Partnership;
- 1.5 million barrels of crude oil and LPG linefill in pipelines owned by third parties;
- 500 trucks and 600 trailers; and
- 1,300 railcars.

In connection with its operations, the marketing segment secures transportation and facilities services from the Partnership's other two segments as well as third-party service providers under month-to-month and multi-year arrangements. Inter-segment transportation service rates are based on posted tariffs for pipeline transportation services. Facilities segment services are also obtained at rates consistent with rates charged to third parties for similar services; however, certain terminalling and storage rates are discounted to our marketing segment to reflect the fact that these services may be canceled on short notice to enable the facilities segment to provide services to third parties.

We purchase crude oil and LPG from multiple producers and believe that we generally have established long-term, broad-based relationships with the crude oil and LPG producers in our areas of operations. Marketing activities involve relatively large volumes of transactions, often with lower margins than transportation and facilities operations. Marketing activities for LPG typically consist of smaller volumes per transaction relative to crude oil.

The following table shows the average daily volume of our lease gathering, LPG sales and waterborne foreign crude imported for the past five years:

	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(Barrels in thousands)				
Crude oil lease gathering	650	610	589	437	410
LPG sales	70	56	48	38	35
Waterborne foreign crude imported	63	59	12	—	—
Total volumes per day	783	725	649	475	445

Crude Oil and LPG Purchases. We purchase crude oil in North America from producers under contracts, the majority of which range in term from a thirty-day evergreen to three-year term. We utilize our truck fleet and gathering pipelines as well as third party pipelines, trucks and barges to transport the crude oil to market. In addition, we purchase foreign crude oil. Under these contracts we may purchase crude oil upon delivery in the U.S. or we may purchase crude oil in foreign locations and transport crude oil on third-party tankers.

We purchase LPG from producers, refiners, and other LPG marketing companies under contracts that range from immediate delivery to one year in term. We utilize leased railcars and third party tank truck or pipelines to transport LPG.

In addition to purchasing crude oil from producers, we purchase both domestic and foreign crude oil in bulk at major pipeline terminal locations and barge facilities. We also purchase LPG in bulk at major pipeline terminal points and storage facilities from major oil companies, large independent producers or other LPG marketing companies. We purchase crude oil and LPG in bulk when we believe additional opportunities exist to realize margins further downstream in the crude oil or LPG distribution chain. The opportunities to earn additional margins vary over time with changing market conditions. Accordingly, the margins associated with our bulk purchases will fluctuate from period to period.

Crude Oil and LPG Sales. The marketing of crude oil and LPG is complex and requires current detailed knowledge of crude oil and LPG sources and end markets and a familiarity with a number of factors including grades of crude oil, individual refinery demand for specific grades of crude oil, area market price structures, location of customers, various modes and availability of transportation facilities and timing and costs (including storage) involved in delivering crude oil and LPG to the appropriate customer.

We sell our crude oil to major integrated oil companies, independent refiners and other resellers in various types of sale and exchange transactions. The majority of these contracts are at market prices and have terms ranging from one month to three years. We sell LPG primarily to retailers and refiners, and limited volumes to other marketers. We establish a margin for crude oil and LPG we purchase by sales for physical delivery to third party users, or by entering into a future delivery obligation with respect to futures contracts on the NYMEX, IntercontinentalExchange ("ICE") or over-the-counter. Through these transactions, we seek to maintain a position that is substantially balanced between crude oil and LPG purchases and sales and future delivery obligations. From time to time, we enter into various types of sale and exchange transactions including fixed price delivery contracts, floating price collar arrangements, financial swaps and crude oil and LPG-related futures contracts as hedging devices.

Crude Oil and LPG Exchanges. We pursue exchange opportunities to enhance margins throughout the gathering and marketing process. When opportunities arise to increase our margin or to acquire a grade, type or volume of crude oil or LPG that more closely matches our physical delivery requirement, location or the preferences of our customers, we exchange physical crude oil or LPG, as appropriate, with third parties. These exchanges are effected through contracts called exchange or buy/sell agreements. Through an exchange agreement, we agree to buy crude oil or LPG that differs in terms of geographic location, grade of crude oil or type of LPG, or physical delivery schedule from crude oil or LPG we have available for sale. Generally, we enter into exchanges to acquire crude oil or LPG at locations that are closer to our end markets, thereby reducing transportation costs and increasing our margin. We also exchange our crude oil to be physically delivered at a later date, if the exchange is expected to result in a higher margin net of storage costs, and enter into exchanges based on the grade of crude oil, which includes such factors as sulfur content and specific gravity, in order to meet the quality specifications of our physical delivery contracts. See Note 2 to our Consolidated Financial Statements.

Credit. Our merchant activities involve the purchase of crude oil and LPG for resale and require significant extensions of credit by our suppliers of crude oil and LPG. In order to assure our ability to perform our obligations under crude oil purchase agreements, various credit arrangements are negotiated with our suppliers. These arrangements include open lines of credit directly with us and, to a lesser extent, standby letters of credit issued under our senior unsecured revolving credit facility.

When we sell crude oil and LPG, we must determine the amount, if any, of the line of credit to be extended to any given customer. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures. If we determine that a customer should receive a credit line, we must then decide on the amount of credit that should be extended.

Because our typical crude oil sales transactions can involve tens of thousands of barrels of crude oil, the risk of nonpayment and nonperformance by customers is a major consideration in our business. We believe our sales are made to creditworthy entities or entities with adequate credit support. Generally, sales of crude oil are settled within 30 days of the month of delivery, and pipeline, transportation and terminalling services also settle within 30 days from invoice for the provision of services.

We also have credit risk with respect to our sales of LPG; however, because our sales are typically in relatively small amounts to individual customers, we do not believe that we have material concentration of credit risk. Typically, we enter into annual contracts to sell LPG on a forward basis, as well as sell LPG on a current basis to local distributors and retailers. In certain cases our customers prepay for their purchases, in amounts ranging from approximately $2 per barrel to 100% of their contracted amounts. Generally, sales of LPG are settled within 30 days of the date of invoice.

Crude Oil Volatility; Counter-Cyclical Balance; Risk Management

Crude oil commodity prices have historically been very volatile and cyclical. For example, NYMEX WTI crude oil benchmark prices have ranged from a high of over $78 per barrel (July 2006) to a low of $10 per barrel (March 1986) over the last 20 years. Segment profit from our facilities activities is dependent on throughput volume, capacity leased to third parties, capacity that we use for our own activities, and the level of other fees generated at our terminalling and storage facilities. Segment profit from our marketing activities is dependent on our ability to sell crude oil and LPG at prices in excess of our aggregate cost. Although margins may be affected during transitional periods, our crude oil marketing operations are not directly affected by the absolute level of crude oil prices, but are affected by overall levels of supply and demand for crude oil and relative fluctuations in market related indices.

During periods when supply exceeds the demand for crude oil in the near term, the market for crude oil is often in contango, meaning that the price of crude oil for future deliveries is higher than current prices. A contango market has a generally negative impact on our lease gathering margins, but is favorable to our commercial strategies that are associated with storage tankage leased from the facilities segment or from third parties. Those who control storage at major trading locations (such as the Cushing Interchange) can simultaneously purchase production at current prices for storage and sell at higher prices for future delivery.

When there is a higher demand than supply of crude oil in the near term, the market is backwardated, meaning that the price of crude oil for future deliveries is lower than current prices. A backwardated market has a positive impact on our lease gathering margins because crude oil gatherers can capture a premium for prompt deliveries. In this environment, there is little incentive to store crude oil as current prices are above future delivery prices.

The periods between a backwardated market and a contango market are referred to as transition periods. Depending on the overall duration of these transition periods, how we have allocated our assets to particular strategies and the time length of our crude oil purchase and sale contracts and storage lease agreements, these transition periods may have either an adverse or beneficial affect on our aggregate segment profit. A prolonged transition from a backwardated market to a contango market, or vice versa (essentially a market that is neither in pronounced backwardation nor contango), represents the most difficult environment for our marketing segment. When the market is in contango, we will use our tankage to improve our lease gathering margins by storing crude oil we have purchased for delivery in future months that are selling at a higher price. In a backwardated market, we use less storage capacity but increased lease gathering margins provide an offset to this reduced cash flow. We believe that the combination of our lease gathering activities and the commercial strategies used with our tankage provides a counter-cyclical balance that has a stabilizing effect on our operations and cash flow. In addition, we supplement the counter-cyclical balance of our asset base with derivative hedging activities in an effort to maintain a base level of margin irrespective of crude oil market conditions and, in certain circumstances, to realize incremental margin during volatile market conditions. References to counter-cyclical balance elsewhere in this report are referring to this relationship between our facilities activities and our marketing activities in transitioning crude oil markets.

As use of the financial markets for crude oil has increased by producers, refiners, utilities and trading entities, risk management strategies, including those involving price hedges using NYMEX and ICE futures contracts and derivatives, have become increasingly important in creating and maintaining margins. In order to hedge margins involving our physical assets and manage risks associated with our various commodity purchase and sale obligations (mainly relating to crude oil) and, in certain circumstances, to realize incremental margin during volatile market conditions, we use derivative instruments, including regulated futures and options transactions, as well as over-the-counter instruments. In analyzing our risk management activities, we draw a distinction between enterprise level risks and trading related risks. Enterprise level risks are those that underlie our core businesses and may be managed based on whether there is value in doing so. Conversely, trading related risks (the risks involved in trading in the hopes of generating an increased return) are not inherent in the core business; rather, those risks arise as a result of engaging in the trading activity. Our risk management policies and procedures are designed to monitor NYMEX, ICE and over-the-counter positions and physical volumes, grades, locations and delivery schedules to ensure that our hedging activities are implemented in accordance with such policies. We have a risk management function that has direct responsibility and authority for our risk policies, our trading controls and procedures and certain other aspects of corporate risk management. Our risk management function also approves all new risk management strategies through a formal process. With the exception of the controlled trading program discussed below, our approved strategies are intended to mitigate enterprise level risks that are inherent in our core businesses of crude oil gathering and marketing and storage.

Our policy is generally to purchase only product for which we have a market, and to structure our sales contracts so that price fluctuations do not materially affect the segment profit we receive. Except for the controlled crude oil trading program discussed below, we do not acquire and hold physical inventory, futures contracts or other derivative products for the purpose of speculating on commodity price changes as these activities could expose us to significant losses.

Although we seek to maintain a position that is substantially balanced within our crude oil lease purchase and LPG activities, we may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil. This controlled trading activity is monitored independently by our risk management function and must take place within predefined limits and authorizations. Such amounts exclude unhedged working inventory volumes that remain relatively constant and are subject to lower of cost or market adjustments.

Although the intent of our risk-management strategies is to hedge our margin, not all of our derivatives qualify for hedge accounting. This could be the result of a derivative that is an effective element of our risk management strategy that may not be sufficiently effective to qualify for hedge accounting or a derivative that is disallowed hedge accounting treatment under SFAS 133 due to the uncertainty of physical delivery. Additionally, certain elements of our risk management strategies such as the time value of options do not qualify for hedge accounting under SFAS 133 whether effective or not. In such instances, changes in the fair values of derivatives that do not qualify or are excluded from hedge accounting will receive mark-to-market treatment in current earnings, and result in greater potential for earnings volatility.

Geographic Data; Financial Information about Segments

See Note 15 to our Consolidated Financial Statements.

Customers

Marathon Petroleum Company, LLC (“Marathon”) accounted for 14%, 11% and 10% of our revenues for each of the three years in the period ended December 31, 2006. Valero Marketing & Supply Company (“Valero”) accounted for 10% of our revenues for the year ended December 31, 2006. BP Oil Supply accounted for 14% and 10% of our revenues for the years ended December 31, 2005 and 2004, respectively. No other customers accounted for 10% or more of our revenues during any of the three years. The majority of revenues from Marathon, Valero and BP Oil Supply pertain to our marketing operations. We believe that the loss of these customers would have only a short-term impact on our operating results. There can be no assurance, however, that we would be able to identify and access a replacement market at comparable margins.

Competition

Competition among pipelines is based primarily on transportation charges, access to producing areas and demand for the crude oil by end users. We believe that high capital requirements, environmental considerations and the difficulty in acquiring rights-of-way and related permits make it unlikely that competing pipeline systems comparable in size and scope to our pipeline systems will be built in the foreseeable future. However, to the extent there are already third party owned pipelines or owners with joint venture pipelines with excess capacity in the vicinity of our operations, we will be exposed to significant competition based on the incremental cost of moving an incremental barrel of crude oil.

We also face competition in our marketing services and facilities services. Our competitors include other crude oil pipeline companies, the major integrated oil companies, their marketing affiliates and independent gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources many times greater than ours, and control greater supplies of crude oil.

Regulation

Our operations are subject to extensive laws and regulations. We are subject to regulatory oversight by numerous federal, state, provincial and local departments and agencies, many of which are authorized by statute to issue and have issued laws and regulations binding on the oil pipeline industry, related businesses and individual participants. The failure to comply with such laws and regulations can result in substantial penalties. The regulatory burden on our operations increases our cost of doing business and, consequently, affects our profitability. However, except for certain exemptions that apply to smaller companies, we do not believe that we are affected in a significantly different manner by these laws and regulations than are our competitors. Following is a discussion of certain laws and regulations affecting us. However, you should not rely on such discussion as an exhaustive review of all regulatory considerations affecting our operations.

Pipeline and Storage Regulation

A substantial portion of our petroleum pipelines and storage tanks in the United States are subject to regulation by the U.S. Department of Transportation's ("DOT") Pipeline and Hazardous Materials Safety Administration with respect to the design, installation, testing, construction, operation, replacement and management of pipeline and tank facilities. Comparable regulation exists in some states in which we conduct intrastate common carrier or private pipeline operations. Regulation in Canada is under the National Energy Board ("NEB") and provincial agencies. In addition, we must permit access to and copying of records, and must make certain reports available and provide information as required by the Secretary of Transportation. U.S. Federal pipeline safety rules also require pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities.

In 2001, the DOT adopted the initial pipeline integrity management rule, which required operators of jurisdictional pipelines transporting hazardous liquids to develop and follow an integrity management program that provides for continual assessment of the integrity of all pipeline segments that could affect so-called "high consequence areas," including high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release, and commercially navigable waterways. In December 2003, the DOT issued a final rule requiring natural gas pipeline operators to develop similar integrity management programs for gas transmission pipelines located in high consequence areas. Segments of our pipelines transporting hazardous liquids and/or natural gas in high consequence areas are subject to these DOT rules and therefore obligate us to evaluate pipeline conditions by means of periodic internal inspection, pressure testing, or other equally effective assessment means, and to correct identified anomalies. If, as a result of our evaluation process, we determine that there is a need to provide further protection to high consequence areas, then we will be required to implement additional spill prevention, mitigation and risk control measures for our pipelines. The DOT rules also require us to evaluate and, as necessary, improve our management and analysis processes for integrating available integrity related data relating to our pipeline segments and to remediate potential problems found as a result of the required assessment and evaluation process. Costs associated with this program were approximately $8.2 million in 2006, $4.7 million in 2005 and approximately $5 million in 2004. Based on currently available information, our preliminary estimate for 2007 is approximately $10.5 million. The relative increase in program cost over the last few years is primarily attributable to pipeline segments acquired in recent years (including the Pacific and Link assets), which are subject to the rules. Certain of these costs are recurring in nature and thus will impact future periods. We will continue to refine our estimates as information from our assessments is collected. Although we believe that our pipeline operations are in substantial compliance with currently applicable regulatory requirements, we cannot predict the potential costs associated with additional, future regulation.

In September 2006, the DOT published a Notice of Proposed Rulemaking ("NPRM") that proposed to regulate certain hazardous liquid gathering and low stress pipeline systems that are not currently subject to regulation. On December 6, 2006, the Congress passed, and on December 29, 2006 President Bush signed into law, H.R. 5782, the "Pipeline Inspection, Protection, Enforcement and Safety Act of 2006" (2006 Pipeline Safety Act), which reauthorizes and amends the DOT's pipeline safety programs. Included in the 2006 Pipeline Safety Act is a provision eliminating the regulatory exemption for hazardous liquid pipelines operated at low stress, which was one of the focal points of the September 2006 NPRM. The Act requires DOT to issue regulations by December 31, 2007 for those hazardous liquid low stress pipelines now subject to regulation pursuant to the 2006 Pipeline Safety Act. Regulations issued by December 31, 2007 with respect to hazardous liquid low stress pipelines as well as any future regulation of hazardous liquid gathering lines could include requirements for the establishment of additional pipeline integrity management programs for these newly regulated pipelines. We do not currently know what, if any, impact these developments will have on our operating expenses and, thus, cannot provide any assurances that future costs related to these programs will not be material.

In addition to performing DOT-mandated pipeline integrity evaluations, during 2006, we expanded an internal review process started in 2005 in which we are reviewing various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management rule. The purpose of this process is to review the surrounding environment, condition and operating history of these pipelines and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, we could be required (as a result of additional DOT regulation) or we may elect (as a result of our own internal initiatives) to spend substantial sums to ensure the integrity of and upgrade our pipeline systems to maintain environmental compliance, and in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines. We cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures for environmental compliance.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with applicable state laws and regulations in those states in which we operate.

The DOT has adopted API 653 as the standard for the inspection, repair, alteration and reconstruction of existing crude oil storage tanks subject to DOT jurisdiction (approximately 79% of our 60 million barrels are subject to DOT jurisdiction). API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Full compliance is required in 2009. Costs associated with this program were approximately $6.8 million, $4.4 million and $3 million in 2006, 2005 and 2004, respectively. Based on currently available information, we anticipate we will spend an approximate average of $15.7 million per year from 2007 through 2009 in connection with API 653 compliance activities. In some cases, we may take storage tanks out of service if we believe the cost of upgrades will exceed the value of the storage tanks or construct replacement tankage at a more optimal location. We will continue to refine our estimates as information from our assessments is collected.

We have instituted security measures and procedures, in accordance with DOT guidelines, to enhance the protection of certain of our facilities from terrorist attack. We cannot provide any assurance that these security measures would fully protect our facilities from a concentrated attack. See "— Operational Hazards and Insurance."

In Canada, the NEB and provincial agencies such as the Alberta Energy and Utilities Board and Saskatchewan Industry and Resources regulate the construction, alteration, inspection and repair of crude oil storage tanks. We expect to incur costs under laws and regulations related to pipeline and storage tank integrity, such as operator competency programs, regulatory upgrades to our operating and maintenance systems and environmental upgrades of buried sump tanks. We spent approximately $4.5 million in 2006, $4.9 million in 2005 and $4.1 million in 2004 on compliance activities. Our preliminary estimate for 2007 is approximately $6.9 million. Certain of these costs are recurring in nature and thus will impact future periods. We will continue to refine our estimates as information from our assessments is collected. Although we believe that our pipeline operations are in substantial compliance with currently applicable regulatory requirements, we cannot predict the potential costs associated with additional, future regulation.

Asset acquisitions are an integral part of our business strategy. As we acquire additional assets, we may be required to incur additional costs in order to ensure that the acquired assets comply with the regulatory standards in the U.S. and Canada.

Transportation Regulation

General Interstate Regulation. Our interstate common carrier pipeline operations are subject to rate regulation by the FERC under the Interstate Commerce Act. The Interstate Commerce Act requires that tariff rates for petroleum pipelines, which include both crude oil pipelines and refined products pipelines, be just and reasonable and non-discriminatory.

State Regulation. Our intrastate pipeline transportation activities are subject to various state laws and regulations, as well as orders of state regulatory bodies, including the California Public Utility Commission, which prohibits certain of our subsidiaries from acting as guarantors of our senior notes and credit facilities. See Note 12 to our Consolidated Financial Statements.

Canadian Regulation. Our Canadian pipeline assets are subject to regulation by the NEB and by provincial authorities, such as the Alberta Energy and Utilities Board. With respect to a pipeline over which it has jurisdiction, the relevant regulatory authority has the power, upon application by a third party, to determine the rates we are allowed to charge for transportation on, and set other terms of access to, such pipeline. In such circumstances, if the relevant regulatory authority determines that the applicable terms and conditions of service are not just and reasonable, the regulatory authority can impose conditions it considers appropriate.

Energy Policy Act of 1992 and Subsequent Developments. In October 1992, Congress passed the Energy Policy Act of 1992 ("EPAct"), which among other things, required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for petroleum pipelines and to streamline procedures in petroleum pipeline proceedings. The FERC responded to this mandate by issuing several orders, including Order No. 561. Beginning January 1, 1995, Order No. 561 enables petroleum pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index. Specifically, the indexing methodology allows a pipeline to increase its rates annually by a percentage equal to the change in the producer price index for finished goods ("PPI-FG") plus 1.3% to the new ceiling level. Rate increases made pursuant to the indexing methodology are subject to protest, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. If the PPI-FG falls and the indexing methodology results in a reduced ceiling level that is lower than a pipeline's filed rate, Order No. 561 requires the pipeline to reduce its rate to comply with the lower ceiling unless doing so would reduce a rate "grandfathered" by EPAct (see below) below the grandfathered level. A pipeline must, as a general rule, utilize the indexing methodology to change its rates. The FERC, however, retained cost-of-service ratemaking, market based rates, and settlement as alternatives to the indexing approach, which alternatives may be used in certain specified circumstances. The FERC's indexing methodology is subject to review every five years; the current methodology is expected to remain in place through June 30, 2011. If the FERC continues its policy of using the PPI-FG plus 1.3%, changes in that index might not fully reflect actual increases in the costs associated with the pipelines subject to indexing, thus hampering our ability to recover cost increases.

The EPAct deemed petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of EPAct that had not been subject to complaint, protest or investigation during that 365-day period to be just and reasonable under the Interstate Commerce Act. Generally, complaints against such "grandfathered" rates may only be pursued if the complainant can show that a substantial change has occurred since the enactment of EPAct in either the economic circumstances of the oil pipeline, or in the nature of the services provided, that were a basis for the rate. EPAct places no such limit on challenges to a provision of an oil pipeline tariff as unduly discriminatory or preferential.

On July 20, 2004, the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") issued its opinion in *BP West Coast Products, LLC v. FERC*, which upheld FERC's determination that certain rates of an interstate petroleum products pipeline, SFPP, L.P. ("SFPP"), were grandfathered rates under EPAct and that SFPP's shippers had not demonstrated substantially changed circumstances that would justify modification of those rates. The court also vacated the portion of the FERC's decision applying the *Lakehead* policy, under which the FERC allowed a regulated entity organized as a master limited partnership (or "MLP") to include in its cost-of-service an income tax allowance to the extent that entity's unitholders were corporations subject to income tax. On May 4, 2005, the FERC adopted a policy statement in Docket No. PL05-5 ("Policy Statement"), stating that it would permit entities owning public utility assets, including oil pipelines, to include an income tax allowance in such utilities' cost-of-service rates to reflect the actual or potential income tax liability attributable to their public utility income, regardless of the form of ownership. Pursuant to the Policy Statement, a tax pass-through entity seeking such an income tax allowance would have to establish that its partners or members have an actual or potential income tax obligation on the entity's public utility income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the new policy is generally favorable for pipelines that are organized as pass-through entities, such as MLPs, it still entails rate risk due to the case-by-case review requirement. The new tax allowance policy has been appealed to the D.C. Circuit. As a result, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC's treatment of income tax allowances in cost of service. FERC continues to refine its tax allowance policy in case-by-case reviews; how the policy statement on income tax allowances is applied in practice to pipelines owned by MLPs, and whether it is ultimately upheld or modified on judicial review, could affect the rates of FERC regulated pipelines.

Additionally, the criteria for establishing substantially changed circumstances under EPAct, among other issues, are currently under review by the D.C. Circuit. Oral argument was held on December 12, 2006, but the court has not yet issued an opinion. We have no way of knowing what effect, if any, action by the FERC and/or the D.C. Circuit on this issue and others might have on our rates should they be challenged.

Our Pipelines. The FERC generally has not investigated rates on its own initiative when those rates have not been the subject of a protest or complaint by a shipper. Substantially all of our segment profit in our transportation segment is produced by rates that are either grandfathered or set by agreement with one or more shippers.

Trucking Regulation

We operate a fleet of trucks to transport crude oil and oilfield materials as a private, contract and common carrier. We are licensed to perform both intrastate and interstate motor carrier services. As a motor carrier, we are subject to certain safety regulations issued by the DOT. The trucking regulations cover, among other things, driver operations, maintaining log books, truck manifest preparations, the placement of safety placards on the trucks and trailer vehicles, drug and alcohol testing, safety of operation and equipment, and many other aspects of truck operations. We are also subject to the Occupational Safety and Health Act, as amended ("OSHA"), with respect to our trucking operations.

Our trucking assets in Canada are subject to regulation by both federal and provincial transportation agencies in the provinces in which they are operated. These regulatory agencies do not set freight rates, but do establish and administer rules and regulations relating to other matters including equipment and driver training and certification, facility inspection, reporting and safety.

Cross Border Regulation

As a result of our Canadian acquisitions and cross border activities, including importation of crude oil into the United States, we are subject to a variety of legal requirements pertaining to such activities including export/import license requirements, tariffs, Canadian and U.S. customs and taxes and requirements relating to toxic substances. U.S. legal requirements relating to these activities include regulations adopted pursuant to the Short Supply Controls of the Export Administration Act, the North American Free Trade Agreement and the Toxic Substances Control Act. Violations of these license, tariff and tax reporting requirements or failure to provide certifications relating to toxic substances could result in the imposition of significant administrative, civil and criminal penalties. Furthermore, the failure to comply with U.S., Canadian, state, provincial and local tax requirements could lead to the imposition of additional taxes, interest and penalties.

Natural Gas Storage Regulation

Interstate Regulation. The interstate storage facilities in which we have an investment are or will be subject to rate regulation by the FERC under the Natural Gas Act. The Natural Gas Act requires that tariff rates for gas storage facilities be just and reasonable and non-discriminatory. The FERC has authority to regulate rates and charges for natural gas transported and stored for U.S. interstate commerce or sold by a natural gas company via interstate commerce for resale. The FERC has granted market-based rate authority under its existing regulations to PAA/Vulcan's Pine Prairie Energy Center, which is under construction in Louisiana, and to its Bluewater gas storage facility.

The FERC also has authority over the construction and operation of U.S. transportation and storage facilities and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. Absent an exemption granted by the FERC, FERC's Standard of Conduct regulations restricted access to U.S. interstate natural gas storage customer data by marketing and other energy affiliates, and placed certain conditions on services provided by the U.S. storage facility operators to their affiliated gas marketing entities. Pine Prairie Energy Center elected to adhere to the Standards of Conduct regulations. However, the Standards of Conduct did not apply to natural gas storage providers authorized to charge market-based rates that are not interconnected with the jurisdictional facilities of any affiliated interstate natural gas pipeline, have no exclusive franchise area, no captive ratepayers, and no market power. The FERC has found that PAA/Vulcan's Pine Prairie Energy Center and its Bluewater facility qualified for this exemption from the Standards of Conduct.

On November 17, 2006, the D.C. Circuit vacated the Standards of Conduct regulations with respect to natural gas pipelines, and remanded the matter to FERC. On January 9, 2007, FERC issued an interim Standards of Conduct rule that reimposed certain of the Standards of Conduct regulations on interstate natural gas transmission providers while narrowing the regulations in a manner that FERC believes is in compliance with the D.C. Circuit's remand. The interim rule continues to exempt natural gas storage providers like PAA/Vulcan's Pine Prairie Energy Center and its Bluewater facility. On January 18, 2007, the FERC issued a Notice of Proposed Rulemaking for new Standards of Conduct regulations. Under the proposed rule, the Standards of Conduct would continue to exempt natural gas storage providers like PAA/Vulcan's Pine Prairie Energy Center and its Bluewater facility. We are unable to predict what Standards of Conduct regulations FERC will ultimately adopt, or whether those regulations will withstand judicial review.

On August 8, 2005, Congress enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, EPAct 2005 amends the Natural Gas Act to add an antimanipulation provision that makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by FERC. On January 19, 2006, the FERC issued Order No. 670, a rule implementing the antimanipulation provision of EPAct 2005. The rules make it unlawful in connection with the purchase or sale of natural gas or transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. The new antimanipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. EPAct 2005 also amends the Natural Gas Act and the Natural Gas Policy Act to give FERC authority to impose civil penalties for violations of the Natural Gas Act up to $1,000,000 per day per violation for violations occurring after August 8, 2005. In connection with this enhanced civil penalty authority, FERC issued a policy statement on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. The antimanipulation rule and enhanced civil penalty authority reflect an expansion of FERC's Natural Gas Act enforcement authority. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. The natural gas industry historically has been heavily regulated. Accordingly, we cannot assure you that the less stringent and pro-competition regulatory approach recently pursued by FERC and Congress will continue.

State Regulation. The intrastate storage facilities in which we have an investment are also subject to regulation by the Michigan State Public Service Commission. Specifically, the Michigan State Public Service Commission has authority to regulate our storage facilities in Michigan with respect to safety and environmental matters.

Environmental, Health and Safety Regulation

General

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons including crude oil are subject to stringent federal, state, provincial and local laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment. As with the industry generally, compliance with these laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, and even the issuance of injunctions that may restrict or prohibit our operations. Environmental laws and regulations are subject to change resulting in more stringent requirements, and we cannot provide any assurance that compliance with current and future laws and regulations will not have a material effect on our results of operations or earnings. A discharge of hazardous liquids into the environment could, to the extent such event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and any claims made by neighboring landowners and other third parties for personal injury and natural resource and property damage.

Water

The U.S. Oil Pollution Act ("OPA") subjects owners of facilities to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages, and certain other consequences of an oil spill, where such spill is into navigable waters, along shorelines or in the exclusive economic zone of the U.S. The OPA establishes a liability limit of $209 million for onshore facilities. However, a party cannot take advantage of this liability limit if the spill is caused by gross negligence or willful misconduct, resulted from a violation of a federal safety, construction, or operating regulation, or if there is a failure to report a spill or cooperate in the cleanup. We believe that we are in substantial compliance with applicable OPA requirements. State and Canadian federal and provincial laws also impose requirements relating to the prevention of oil releases and the remediation of areas affected by releases when they occur. We believe that we are in substantial compliance with all such state and Canadian requirements.

The U.S. Clean Water Act and state and Canadian federal and provincial laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters of the United States and Canada, as well as state and provincial waters. See Note 11 to our Consolidated Financial Statements. Permits or approvals must be obtained to discharge pollutants into these waters. The Clean Water Act imposes substantial potential liability for the removal and remediation of pollutants. Although we can give no assurances, we believe that compliance with existing permits and compliance with foreseeable new permit or approval requirements will not have a material adverse effect on our financial condition or results of operations.

Some states and all provinces maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. We believe that we are in substantial compliance with any such applicable state and provincial requirements.

In addition to the costs described above we could also be required to spend substantial sums to ensure the integrity of and upgrade our pipeline systems as a result of oil releases, and in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines. We cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures for environmental compliance.

Air Emissions

Our operations are subject to the U.S. Clean Air Act and comparable state and provincial laws. Under these laws, permits may be required before construction can commence on a new source of potentially significant air emissions and operating permits may be required for sources already constructed. We may be required to incur certain capital and operating expenditures in the next several years for installing air pollution control equipment and otherwise complying with more stringent state and regional air emissions control plans in connection with obtaining or maintaining permits and approvals for sources of air emissions. Although we believe that our operations are in substantial compliance with these laws in those areas in which we operate, we can provide no assurance that future compliance obligations will not have a material adverse effect on our financial condition or results of operations.

Further, in response to recent studies suggesting that emissions of carbon dioxide and certain other gases may be contributing to warming of the Earth's atmosphere, many foreign nations, including Canada, have agreed to limit emissions of these gases, generally referred to as "greenhouse gases," pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol." The Kyoto Protocol requires Canada to reduce its emissions of "greenhouse gases" to 6% below 1990 levels by 2012. As a result, it is possible that already stringent air emissions regulations applicable to our operations in Canada will be replaced with even stricter requirements prior to 2012. Although the United States is not participating in the Kyoto Protocol, the current session of Congress is considering climate change-related legislation, with multiple bills having already been introduced in the Senate that propose to restrict greenhouse gas emissions. Also, several states have adopted legislation, regulations and/or regulatory initiatives to reduce emissions of greenhouse gases. For instance, California recently adopted the "California Global Warming Solutions Act of 2006," which requires the California Air Resources Board to achieve a 25% reduction in emissions of greenhouse gases from sources in California by 2020. Additionally, on November 29, 2006, the U.S. Supreme Court heard arguments on a case appealed from the U.S. Circuit Court of Appeals for the District of Columbia, *Massachusetts, et al. v. EPA* , in which the appellate court held that the EPA had discretion under the federal Clean Air Act to refuse to regulate carbon dioxide emission from mobile sources. Passage of climate control legislation by Congress or a Supreme Court reversal of the appellate decision could result in federal regulation of carbon dioxide emissions and other greenhouse gases. Any federal, provincial or state restrictions on emissions of greenhouse gases that may be imposed in areas of the United States in which we conduct business or in Canada prior to 2012 could adversely affect our operations and demand for our products.

Solid Waste

We generate wastes, including hazardous wastes, that are subject to the requirements of the federal Resource Conservation and Recovery Act ("RCRA") and state and provincial laws. We are not required to comply with a substantial portion of the RCRA requirements because our operations generate primarily oil and gas wastes, which currently are excluded from consideration as RCRA hazardous wastes. However, it is possible that in the future oil and gas wastes may be included as RCRA hazardous wastes, in which event our wastes as well as the wastes of our competitors in the oil and gas industry will be subject to more rigorous and costly disposal requirements, resulting in additional capital expenditures or operating expenses for us and the industry in general.

Hazardous Substances

The federal Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as "Superfund," and comparable state laws impose liability, without regard to fault or the legality of the original act, on certain classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site or sites where the release occurred and companies that disposed of, or arranged for the disposal of, the hazardous substances found at the site. Canadian and provincial laws also impose liabilities for releases of certain substances into the environment. Under CERCLA, such persons may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our ordinary operations, we may generate waste that falls within CERCLA's definition of a "hazardous substance," in which event we may be held jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which such hazardous substances have been released into the environment.

OSHA

We are subject to the requirements of OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that certain information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with OSHA requirements, including general industry standards, record-keeping requirements and monitoring of occupational exposure to regulated substances. OSHA has also been given jurisdiction over enforcement of legislation designed to protect employees who provide evidence in fraud cases from retaliation by their employer.

Similar regulatory requirements exist in Canada under the federal and provincial Occupational Health and Safety Acts and related regulations. The agencies with jurisdiction under these regulations are empowered to enforce them through inspection, audit, incident investigation or public or employee complaint. Additionally, under the Criminal Code of Canada, organizations, corporations and individuals may be prosecuted criminally for violating the duty to protect employee and public safety. We believe that our operations are in substantial compliance with applicable occupational health and safety requirements.

Endangered Species Act

The federal Endangered Species Act ("ESA") restricts activities that may affect endangered species or their habitats. Although certain of our facilities are in areas that may be designated as habitat for endangered species, we believe that we are in substantial compliance with the ESA. However, the discovery of previously unidentified endangered species could cause us to incur additional costs or operational restrictions or bans in the affected area, which costs, restrictions, or bans could have a material adverse effect on our financial condition or results of operations. Legislation in Canada for the protection of species at risk and their habitat (the Species at Risk Act) applies to our Canadian operations.

Hazardous Materials Transportation Requirements

The federal and analogous state DOT regulations affecting pipeline safety require pipeline operators to implement measures designed to reduce the environmental impact of oil discharge from onshore oil pipelines. These regulations require operators to maintain comprehensive spill response plans, including extensive spill response training for pipeline personnel. In addition, DOT regulations contain detailed specifications for pipeline operation and maintenance. We believe our operations are in substantial compliance with such regulations. See "— Regulation — Pipeline and Storage Regulation."

Environmental Remediation

We currently own or lease properties where hazardous liquids, including hydrocarbons, are being or have been handled. These properties and the hazardous liquids or associated generated wastes disposed thereon may be subject to CERCLA, RCRA and state and Canadian federal and provincial laws and regulations. Under such laws and regulations, we could be required to remove or remediate hazardous liquids or associated generated wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination.

We maintain insurance of various types with varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. Consistent with insurance coverage generally available in the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences.

In addition, we have entered into indemnification agreements with various counterparties in conjunction with several of our acquisitions. Allocation of environmental liability is an issue negotiated in connection with each of our acquisition transactions. In each case, we make an assessment of potential environmental exposure based on available information. Based on that assessment and relevant economic and risk factors, we determine whether to negotiate an indemnity, what the terms of any indemnity should be (for example, minimum thresholds or caps on exposure) and whether to obtain insurance, if available. In some cases, we have received contractual protections in the form of environmental indemnifications from several predecessor operators for properties acquired by us that are contaminated as a result of historical operations. These contractual indemnifications typically are subject to specific monetary requirements that must be satisfied before indemnification will apply and have term and total dollar limits.

For instance, in connection with the purchase of assets from Link in 2004, we identified a number of environmental liabilities for which we received a purchase price reduction from Link and recorded a total environmental reserve of $20 million. A substantial portion of these environmental liabilities are associated with the former Texas New Mexico ("TNM") pipeline assets. On the effective date of the acquisition, we and TNM entered into a cost-sharing agreement whereby, on a tiered basis, we agreed to bear $11 million of the first $20 million of pre-May 1999 environmental issues. We also agreed to bear the first $25,000 per site for new sites which were not identified at the time we entered into the agreement (capped at 100 sites). TNM agreed to pay all costs in excess of $20 million (excluding the deductible for new sites). TNM's obligations are guaranteed by Shell Oil Products ("SOP"). As of December 31, 2006, we had incurred approximately $7 million of remediation costs associated with these sites; SOP's share is approximately $1.5 million.

In connection with the acquisition of certain crude oil transmission and gathering assets from SOP in 2002, SOP purchased an environmental insurance policy covering known and unknown environmental matters associated with operations prior to closing. We are a named beneficiary under the policy, which has a $100,000 deductible per site, an aggregate coverage limit of $70 million, and expires in 2012. SOP made a claim against the policy; however, we do not believe that the claim substantially reduced our coverage under the policy.

In connection with our 1999 acquisition of Scurlock Permian LLC from MAP, we were indemnified by MAP for any environmental liabilities attributable to Scurlock's business or properties that occurred prior to the date of the closing of the acquisition. Other than with respect to liabilities associated with two Superfund sites at which it is alleged that Scurlock deposited waste oils, this indemnity has expired or was terminated by agreement.

As a result of our merger with Pacific, we have assumed liability for a number of ongoing remediation sites, associated with releases from pipeline or storage operations. These sites had been managed by Pacific prior to the merger, and in general there is no insurance or indemnification to cover ongoing costs to address these sites (with the exception of the Pyramid Lake crude oil release, which is discussed in Item 3. "Legal Proceedings"). We have evaluated each of the sites requiring remediation, through review of technical and regulatory documents, discussions with Pacific, and our experience at investigating and remediating releases from pipeline and storage operations. We have developed reserve estimates for the Pacific sites based on this evaluation, including determination of current and long-term reserve amounts, which total approximately $21.8 million.

Other assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified.

Environmental. We have in the past experienced and in the future likely will experience releases of crude oil or petroleum products into the environment from our pipeline and storage operations. We also may discover environmental impacts from past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business. As we expand our pipeline assets through acquisitions, we typically improve on (decrease) the rate of releases from such assets as we implement our standards and procedures, remove selected assets from service and spend capital to upgrade the assets. In the immediate post-acquisition period, however, the inclusion of additional miles of pipe in our operation may result in an increase in the absolute number of releases company-wide compared to prior periods. We experienced such an increase in connection with the Pacific acquisition, which added approximately 5,000 miles of pipeline to our operations, and in connection with the Link acquisition, which added approximately 7,000 miles of pipeline to our operations. As a result, we have also received an increased number of requests for information from governmental agencies with respect to such releases of crude oil (such as EPA requests under Clean Water Act Section 308), commensurate with the scale and scope of our pipeline operations. See Item 3. "Legal Proceedings."

At December 31, 2006, our reserve for environmental liabilities totaled approximately $39.1 million (approximately $21.8 million of this reserve is related to liabilities assumed as part of the Pacific merger, and $10.4 million is related to liabilities assumed as part of the Link acquisition). Approximately $19.5 million of our environmental reserve is classified as current and $19.6 million is classified as long-term. At December 31, 2006, we have recorded receivables totaling approximately $11.6 million for amounts recoverable under insurance and from third parties under indemnification agreements.

In some cases, the actual cash expenditures may not occur for three to five years. Our estimates used in these reserves are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional claims. Therefore, although we believe that the reserve is adequate, no assurances can be made that any costs incurred in excess of this reserve or outside of the indemnifications would not have a material adverse effect on our financial condition, results of operations, or cash flows.

Operational Hazards and Insurance

Pipelines, terminals, trucks or other facilities or equipment may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. Since we and our predecessors commenced midstream crude oil activities in the early 1990s, we have maintained insurance of various types and varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. However, such insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. Consistent with insurance coverage generally available to the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences. Over the last several years, our operations have expanded significantly, with total assets increasing over 1,300% since the end of 1998. At the same time that the scale and scope of our business activities have expanded, the breadth and depth of the available insurance markets have contracted. The overall cost of such insurance as well as the deductibles and overall retention levels that we maintain have increased. Some of this may be attributable to the events of September 11, 2001, which adversely impacted the availability and costs of certain types of coverage. Certain aspects of these conditions were further exacerbated by the hurricanes along the Gulf Coast during 2005, which also had an adverse effect on the availability and cost of coverage. As a result, we have elected to self-insure more activities against certain of these operating hazards and expect this trend will continue in the future. Due to the events of September 11, 2001, insurers have excluded acts of terrorism and sabotage from our insurance policies. On certain of our key assets, we have elected to purchase a separate insurance policy for acts of terrorism and sabotage.

Since the terrorist attacks, the United States Government has issued numerous warnings that energy assets, including our nation's pipeline infrastructure, may be future targets of terrorist organizations. These developments expose our operations and assets to increased risks. We have instituted security measures and procedures in conformity with DOT guidance. We will institute, as appropriate, additional security measures or procedures indicated by the DOT or the Transportation Safety Administration. However, we cannot assure you that these or any other security measures would protect our facilities from a concentrated attack. Any future terrorist attacks on our facilities, those of our customers and, in some cases, those of our competitors, could have a material adverse effect on our business, whether insured or not.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. We believe that our levels of coverage and retention are generally consistent with those of similarly situated companies in our industry. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable, or that we have established adequate reserves to the extent that such risks are not insured.

Title to Properties and Rights-of-Way

We believe that we have satisfactory title to all of our assets. Although title to such properties is subject to encumbrances in certain cases, such as customary interests generally retained in connection with acquisition of real property, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens and minor easements, restrictions and other encumbrances to which the underlying properties were subject at the time of acquisition by our predecessor, or subsequently granted by us, we believe that none of these burdens will materially detract from the value of such properties or from our interest therein or will materially interfere with their use in the operation of our business.

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of such property and, in some instances, such rights-of-way are revocable at the election of the grantor. In many instances, lands over which rights-of-way have been obtained are subject to prior liens that have not been subordinated to the right-of-way grants. In some cases, not all of the apparent record owners have joined in the right-of-way grants, but in substantially all such cases, signatures of the owners of majority interests have been obtained. 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, such 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. All of the pump stations are located on property owned in fee or property under leases. In certain states and under certain circumstances, we have the right of eminent domain to acquire rights-of-way and lands necessary for our common carrier pipelines.

Some of the leases, easements, rights-of-way, permits and licenses transferred to us, upon our formation in 1998 and in connection with acquisitions we have made since that time, required the consent of the grantor to transfer such rights, which in certain instances is a governmental entity. We believe that we have obtained such third party consents, permits and authorizations as are sufficient for the transfer to us of the assets necessary for us to operate our business in all material respects as described in this report. With respect to any consents, permits or authorizations that have not yet been obtained, we believe that such consents, permits or authorizations will be obtained within a reasonable period, or that the failure to obtain such consents, permits or authorizations will have no material adverse effect on the operation of our business.

Employees and Labor Relations

To carry out our operations, our general partner or its affiliates (including PMC (Nova Scotia) Company) employed approximately 2,900 employees at December 31, 2006. None of the employees of our general partner were subject to a collective bargaining agreement, except for nine employees at our Paulsboro, New Jersey terminal, who are members of USW District 10-286 (Steel Workers), with whom we have a collective bargaining agreement that will end on October 1, 2009. Our general partner considers its employee relations to be good.

Summary of Tax Considerations

The tax consequences of ownership of common units depends in part on the owner's individual tax circumstances. However, the following is a brief summary of material tax considerations of owning and disposing of common units.

Partnership Status; Cash Distributions

We are treated for federal income tax purposes as a partnership based upon our meeting certain requirements imposed by the Internal Revenue Code (the "Code"), which we must meet each year. The owners of common units are considered partners in the Partnership so long as they do not loan their common units to others to cover short sales or otherwise dispose of those units. Accordingly, we pay no U.S. federal income taxes, and a common unitholder is required to report on the unitholder's federal income tax return the unitholder's share of our income, gains, losses and deductions. In general, cash distributions to a common unitholder are taxable only if, and to the extent that, they exceed the tax basis in the common units held. In certain cases, we are subject to, or have paid Canadian income and withholding taxes. Canadian withholding taxes are due on intercompany interest payments and credits and dividend payments.

Partnership Allocations

In general, our income and loss is allocated to the general partner and the unitholders for each taxable year in accordance with their respective percentage interests in the Partnership (including, with respect to the general partner, its incentive distribution right), as determined annually and prorated on a monthly basis and subsequently apportioned among the general partner and the unitholders of record as of the opening of the first business day of the month to which they relate, even though unitholders may dispose of their units during the month in question. In determining a unitholder's federal income tax liability, the unitholder is required to take into account the unitholder's share of income generated by us for each taxable year of the Partnership ending with or within the unitholder's taxable year, even if cash distributions are not made to the unitholder. As a consequence, a unitholder's share of our taxable income (and possibly the income tax payable by the unitholder with respect to such income) may exceed the cash actually distributed to the unitholder by us. At any time incentive distributions are made to the general partner, gross income will be allocated to the recipient to the extent of those distributions.

Basis of Common Units

A unitholder's initial tax basis for a common unit is generally the amount paid for the common unit and the unitholder's share of our nonrecourse liabilities. A unitholder's basis is generally increased by the unitholder's share of our income and by any increases in the unitholder's share of our nonrecourse liabilities. That basis will be decreased, but not below zero, by the unitholder's share of our losses and distributions (including deemed distributions due to a decrease in the unitholder's share of our nonrecourse liabilities).

Limitations on Deductibility of Partnership Losses

In the case of taxpayers subject to the passive loss rules (generally, individuals and closely held corporations), any partnership losses are only available to offset future income generated by us and cannot be used to offset income from other activities, including passive activities or investments. Any losses unused by virtue of the passive loss rules may be fully deducted if the unitholder disposes of all of the unitholder's common units in a taxable transaction with an unrelated party.

Section 754 Election

We have made the election provided for by Section 754 of the Code, which will generally result in a unitholder being allocated income and deductions calculated by reference to the portion of the unitholder's purchase price attributable to each asset of the Partnership.

Disposition of Common Units

A unitholder who sells common units will recognize gain or loss equal to the difference between the amount realized and the adjusted tax basis of those common units. A unitholder may not be able to trace basis to particular common units for this purpose. Thus, distributions of cash from us to a unitholder in excess of the income allocated to the unitholder will, in effect, become taxable income if the unitholder sells the common units at a price greater than the unitholder's adjusted tax basis even if the price is less than the unitholder's original cost. Moreover, a portion of the amount realized (whether or not representing gain) will 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 our nonrecourse liabilities, a unitholder may incur a tax liability in excess of the amount of cash the unitholder receives from the sale.

Foreign, State, Local and Other Tax Considerations

In addition to federal income taxes, unitholders will likely be subject to other taxes, such as foreign, state and local income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which a unitholder resides or in which we conduct business or own property. We own property and conduct business in Canada as well as in most states in the United States. A unitholder will therefore be required to file Canadian federal income tax returns and to pay Canadian federal and provincial income taxes in respect of our Canadian source income earned through partnership entities. A unitholder may also be required to file state income tax returns and to pay taxes in various states. A unitholder may be subject to interest and penalties for failure to comply with such requirements. In certain states, tax losses may not produce a tax benefit in the year incurred (if, for example, we have no income from sources within that state) and also may not be available to offset income in subsequent taxable years. Some states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be more or less than a particular unitholder's income tax liability owed to a particular state, may not relieve the unitholder from the obligation to file an income tax return in that state. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

It is the responsibility of each prospective unitholder to investigate the legal and tax consequences, under the laws of pertinent states and localities, including the Canadian provinces and Canada, of the unitholder's investment in us. Further, it is the responsibility of each unitholder to file all U.S. federal, Canadian, state, provincial and local tax returns that may be required of the unitholder.

Ownership of Common Units by Tax-Exempt Organizations and Certain Other Investors

An investment in common units by tax-exempt organizations (including IRAs and other retirement plans) and foreign persons raises issues unique to such persons. Virtually all of our income allocated to a unitholder that is a tax-exempt organization is unrelated business taxable income and, thus, is taxable to such a unitholder. A unitholder who is a nonresident alien, foreign corporation or other foreign person is regarded as being engaged in a trade or business in the United States as a result of ownership of a common unit and, thus, is required to file federal income tax returns and to pay tax on the unitholder's share of our taxable income. Finally, distributions to foreign unitholders are subject to federal income tax withholding.

Available Information

We make available, free of charge on our Internet website (http://www.paalp.com), 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 the material with, or furnish it to, the Securities and Exchange Commission.

Risk Factors

Risks Related to Our Business

Our trading policies cannot eliminate all price risks. In addition, any non-compliance with our trading policies could result in significant financial losses.

Generally, it is our policy that we establish a margin for crude oil we purchase by selling crude oil for physical delivery to third party users, such as independent refiners or major oil companies, or by entering into a future delivery obligation under futures contracts on the NYMEX, ICE and over-the-counter. Through these transactions, we seek to maintain a position that is substantially balanced between purchases on the one hand, and sales or future delivery obligations on the other hand. Our policy is generally not to acquire and hold physical inventory, futures contracts or derivative products for the purpose of speculating on commodity price changes. These policies and practices cannot, however, eliminate all price risks. For example, any event that disrupts our anticipated physical supply of crude oil could expose us to risk of loss resulting from price changes. We are also exposed to basis risk when crude oil is purchased against one pricing index and sold against a different index. Moreover, we are exposed to some risks that are not hedged, including price risks on certain of our inventory, such as linefill, which must be maintained in order to transport crude oil on our pipelines. In addition, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil. Although this activity is monitored independently by our risk management function, it exposes us to price risks within predefined limits and authorizations.

In addition, our trading operations involve the risk of non-compliance with our trading policies. For example, we discovered in November 1999 that our trading policy was violated by one of our former employees, which resulted in aggregate losses of approximately $181.0 million. We have taken steps within our organization to enhance our processes and procedures to detect future unauthorized trading. We cannot assure you, however, that these steps will detect and prevent all violations of our trading policies and procedures, particularly if deception or other intentional misconduct is involved.

The nature of our business and assets exposes us to significant compliance costs and liabilities. Our asset base has more than tripled within the last three years. We have experienced a corresponding increase in the relative number of releases of crude oil to the environment. Substantial expenditures may be required to maintain the integrity of aged and aging pipelines and terminals at acceptable levels.

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons, including crude oil and refined products, as well as our operations involving the storage of natural gas, are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment. Our operations are also subject to laws and regulations relating to protection of the environment, operational safety and related matters. Compliance with all of these laws and regulations increases our overall cost of doing business, including our capital costs to construct, maintain and upgrade equipment and facilities. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, the issuance of injunctions that may restrict or prohibit our operations, or claims of damages to property or persons resulting from our operations. The laws and regulations applicable to our operations are subject to change and interpretation by the relevant governmental agency. Any such change or interpretation adverse to us could have a material adverse effect on our operations, revenues and profitability.

Today we own approximately three times the miles of pipeline we owned three years ago. As we have expanded our pipeline assets, we have observed a corresponding increase in the number of releases of crude oil to the environment. These releases expose us to potentially substantial expense, including clean-up and remediation costs, fines and penalties, and third party claims for personal injury or property damage related to past or future releases. Some of these expenses could increase by amounts disproportionately higher than the relative increase in pipeline mileage and the increase in revenues associated therewith. During 2006, we entered the refined products pipeline and terminalling businesses through the acquisition of three products pipeline systems in West Texas and New Mexico and through the acquisition of Pacific, which had refined product assets in California, the U.S. Rockies and Pennsylvania. These businesses are also subject to significant compliance costs and liabilities. In addition, because of their increased volatility and tendency to migrate farther and faster than crude oil, releases of refined products into the environment can have more significant impact than crude oil and require significantly higher expenditures to respond and remediate. The incurrence of such expenses not covered by insurance, indemnity or reserves could materially adversely affect our results of operations.

We currently spend substantial amounts to comply with DOT-mandated pipeline integrity rules. The 2006 Pipeline Safety Act, enacted in December 2006, requires the DOT to issue regulations for certain pipelines that were not previously subject to regulation. These regulations could include requirements for the establishment of additional pipeline integrity management programs for these newly regulated pipelines. We do not currently know what, if any, impact this will have on our operating expenses.

In addition to performing DOT-mandated pipeline integrity evaluations, during 2006, we expanded an internal review process started in 2005 pursuant to which we review various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management rules. The purpose of this process is to review the surrounding environment, condition and operating history of these pipeline and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, we could be required (as a result of additional DOT regulation) or we may elect (as a result of our own internal initiatives) to spend substantial sums to ensure the integrity of and upgrade our pipeline systems to maintain environmental compliance and, in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines. We cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures for environmental compliance.

Loss of credit rating or the ability to receive open credit could negatively affect our ability to use the counter-cyclical aspects of our asset base or to capitalize on a volatile market.

We believe that, because of our strategic asset base and complementary business model, we will continue to benefit from swings in market prices and shifts in market structure during periods of volatility in the crude oil market. Our ability to capture that benefit, however, is subject to numerous risks and uncertainties, including our maintaining an attractive credit rating and continuing to receive open credit from our suppliers and trade counter-parties.

We may not be able to fully implement or capitalize upon planned growth projects.

We have a number of organic growth projects that require the expenditure of significant amounts of capital, including the Pier 400 project, the Salt Lake City expansion, the Cheyenne pipeline project, the Pine Prairie joint venture and the St. James, Cushing and Patoka terminal projects. Many of these projects involve numerous regulatory, environmental, weather-related, political and legal uncertainties that will be beyond our control. As these projects are undertaken, required approvals may not be obtained, may be delayed or may be obtained with conditions that materially alter the expected return associated with the underlying projects. Moreover, revenues associated with these organic growth projects will not increase immediately upon the expenditures of funds with respect to a particular project and these projects may be completed behind schedule or in excess of budgeted cost. Because of continuing increased demand for materials, equipment and services, there could be shortages and cost increases associated with construction projects. We may construct pipelines, facilities or other assets in anticipation of market demand that dissipates or market growth that never materializes. As a result of these uncertainties, the anticipated benefits associated with our capital projects may not be achieved.

The level of our profitability is dependent upon an adequate supply of crude oil from fields located offshore and onshore California. A shut-in of this production due to economic limitations or a significant event could adversely affect our profitability. In addition, these offshore fields have experienced substantial production declines since 1995.

A significant portion of our segment profit is derived from pipeline transportation margins associated with the Santa Ynez and Point Arguello fields located offshore California and the onshore fields in the San Joaquin Valley. We expect that there will continue to be natural production declines from each of these fields as the underlying reservoirs are depleted. We estimate that a 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual transportation segment profit of approximately $6.1 million. A similar decline in volumes shipped from the San Joaquin Valley would result in an estimated $3.2 million decrease in annual transportation segment profit. In addition, any significant production disruption from the outer continental shelf fields and the San Joaquin Valley due to production problems, transportation problems or other reasons could have a material adverse effect on our business.

Our profitability depends on the volume of crude oil, refined product and LPG shipped, purchased and gathered.

Third party shippers generally do not have long-term contractual commitments to ship crude oil on our pipelines. A decision by a shipper to substantially reduce or cease to ship volumes of crude oil on our pipelines could cause a significant decline in our revenues. For example, we estimate that an average 20,000 barrel per day variance in the Basin Pipeline System within the current operating window, equivalent to an approximate 7% volume variance on that system, would change annualized segment profit by approximately $1.8 million. In addition, we estimate that an average 10,000 barrel per day variance on the Capline Pipeline System, equivalent to an approximate 8% volume variance on that system, would change annualized segment profit by approximately $1.3 million.

To maintain the volumes of crude oil we purchase in connection with our operations, we must continue to contract for new supplies of crude oil to offset volumes lost because of natural declines in crude oil production from depleting wells or volumes lost to competitors. Replacement of lost volumes of crude oil is particularly difficult in an environment where production is low and competition to gather available production is intense. Generally, because producers experience inconveniences in switching crude oil purchasers, such as delays in receipt of proceeds while awaiting the preparation of new division orders, producers typically do not change purchasers on the basis of minor variations in price. Thus, we may experience difficulty acquiring crude oil at the wellhead in areas where relationships already exist between producers and other gatherers and purchasers of crude oil. We estimate that a 15,000 barrel per day decrease in barrels gathered by us would have an approximate $2.7 million per year negative impact on segment profit. This impact assumes a reasonable margin throughout various market conditions. Actual margins vary based on the location of the crude oil, the strength or weakness of the market and the grade or quality of crude oil. We estimate that a $0.01 variance in the average segment profit per barrel would have an approximate $4.2 million annual effect on segment profit.

Fluctuations in demand can negatively affect our operating results.

Demand for crude oil is dependent upon the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand. Demand also depends on the ability and willingness of shippers having access to our transportation assets to satisfy their demand by deliveries through those assets.

Fluctuations in demand for crude oil, such as caused by refinery downtime or shutdown, can have a negative effect on our operating results. Specifically, reduced demand in an area serviced by our transmission systems will negatively affect the throughput on such systems. Although the negative impact may be mitigated or overcome by our ability to capture differentials created by demand fluctuations, this ability is dependent on location and grade of crude oil, and thus is unpredictable.

If we do not make acquisitions on economically acceptable terms our future growth may be limited.

Our ability to grow depends in part on our ability to make acquisitions that result in an increase in adjusted operating surplus per unit. If we are unable to make such accretive acquisitions either because we are (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with the sellers, (ii) unable to raise financing for such acquisitions on economically acceptable terms or (iii) outbid by competitors, our future growth will be limited. In particular, competition for midstream assets and businesses has intensified substantially and as a consequence such assets and businesses have become more costly. As a result, we may not be able to complete the number or size of acquisitions that we have targeted internally or to continue to grow as quickly as we have historically.

Our acquisition strategy requires access to new capital. Tightened capital markets or other factors that increase our cost of capital could impair our ability to grow through acquisitions.

We continuously consider and enter into discussions regarding potential acquisitions. These transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets and operations. Any material acquisition will require access to capital. Any limitations on our access to capital or increase in the cost of that capital could significantly impair our ability to execute our acquisition strategy. Our ability to maintain our targeted credit profile, including maintaining our credit ratings, could affect our cost of capital as well as our ability to execute our acquisition strategy.

Our acquisition strategy involves risks that may adversely affect our business.

Any acquisition involves potential risks, including:

- performance from the acquired assets and businesses that is below the forecasts we used in evaluating the acquisition;
- a significant increase in our indebtedness and working capital requirements;
- the inability to timely and effectively integrate the operations of recently acquired businesses or assets;
- the incurrence of substantial unforeseen environmental and other liabilities arising out of the acquired businesses or assets, including liabilities arising from the operation of the acquired businesses or assets prior to our acquisition;
- risks associated with operating in lines of business that are distinct and separate from our historical operations;
- customer or key employee loss from the acquired businesses; and
- the diversion of management’s attention from other business concerns.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows from our acquisitions, realize other anticipated benefits and our ability to pay distributions or meet our debt service requirements.

Our pipeline assets are subject to federal, state and provincial regulation. Rate regulation or a successful challenge to the rates we charge on our domestic interstate pipeline system may reduce the amount of cash we generate.

Our domestic interstate common carrier pipelines are subject to regulation by the FERC under the Interstate Commerce Act. The Interstate Commerce Act requires that tariff rates for petroleum pipelines be just and reasonable and non-discriminatory. We are also subject to the Pipeline Safety Regulations of the DOT. Our intrastate pipeline transportation activities are subject to various state laws and regulations as well as orders of regulatory bodies.

The EPAct, among other things, deems “just and reasonable” within the meaning of the Interstate Commerce Act any oil pipeline rate in effect for the 365-day period ending on the date of the enactment of EPAct if the rate in effect was not subject to protest, investigation, or complaint during such 365-day period. (That is, the EPAct “grandfathers” any such rates.) The EPAct further protects any rate meeting this requirement from complaint unless the complainant can show that a substantial change occurred after the enactment of EPAct in the economic circumstances of the oil pipeline which were the basis for the rate or in the nature of the services provided which were a basis for the rate. This grandfathering protection does not apply, under certain specified circumstances, when the person filing the complaint was under a contractual prohibition against the filing of a complaint.

For our domestic interstate common carrier pipelines subject to FERC regulation under the Interstate Commerce Act, 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 and for rates that remain grandfathered under EPAct, the FERC may order refunds of amounts collected under rates that were in excess of a just and reasonable level when taking into consideration the pipeline system’s cost of service. In addition, shippers may challenge the lawfulness of tariff rates that have become final and effective. The FERC may also investigate such rates absent shipper complaint. The FERC’s ratemaking methodologies may limit our ability to set rates based on our true costs or may delay the use of rates that reflect increased costs.

The potential for a challenge to the status of our grandfathered rates under EPAct (by showing a substantial change in circumstances) or a challenge to our indexed rates creates the risk that the FERC might find some of our rates to be in excess of a just and reasonable level — that is, a level justified by our cost of service. In such an event, the FERC could order us to reduce any such rates and could require the payment of reparations to complaining shippers for up to two years prior to the complaint.

Our Canadian pipelines are subject to regulation by the NEB or by provincial authorities. Under the National Energy Board Act, the NEB could investigate the tariff rates or the terms and conditions of service relating to a jurisdictional pipeline on its own initiative upon the filing of a toll or tariff application, or upon the filing of a written complaint. If it found the rates or terms of service relating to such pipeline to be unjust or unreasonable or unjustly discriminatory, the NEB could require us to change our rates, provide access to other shippers, or change our terms of service. A provincial authority could, on the application of a shipper or other interested party, investigate the tariff rates or our terms and conditions of service relating to our provincially regulated proprietary pipelines. If it found our rates or terms of service to be contrary to statutory requirements, it could impose conditions it considers appropriate. A provincial authority could declare a pipeline to be a common carrier pipeline, and require us to change our rates, provide access to other shippers, or otherwise alter our terms of service. Any reduction in our tariff rates would result in lower revenue and cash flows.

Some of our operations cross the U.S./Canada border and are subject to cross border regulation.

Our cross border activities with our Canadian subsidiaries subject us to regulatory matters, including import and export licenses, tariffs, Canadian and U.S. customs and tax issues and toxic substance certifications. Regulations include the Short Supply Controls of the Export Administration Act, the North American Free Trade Agreement and the Toxic Substances Control Act. Violations of these licensing, tariff and tax reporting requirements could result in the imposition of significant administrative, civil and criminal penalties.

We face competition in our transportation, facilities and marketing activities.

Our competitors include other crude oil pipelines, the major integrated oil companies, their marketing affiliates, and independent gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources many times greater than ours and control greater supplies of crude oil.

With respect to our natural gas storage operations, we compete with other storage providers, including local distribution companies (“LDCs”), utilities and affiliates of LDCs and utilities. Certain major pipeline companies have existing storage facilities connected to their systems that compete with certain of our facilities. Third-party construction of new capacity could have an adverse impact on our competitive position.

We are exposed to the credit risk of our customers in the ordinary course of our marketing activities.

There can be no assurance that we have adequately assessed the creditworthiness of our existing or future counterparties or that there will not be an unanticipated deterioration in their creditworthiness, which could have an adverse impact on us.

In those cases in which we provide division order services for crude oil purchased at the wellhead, we may be responsible for distribution of proceeds to all parties. In other cases, we pay all of or a portion of the production proceeds to an operator who distributes these proceeds to the various interest owners. These arrangements expose us to operator credit risk, and there can be no assurance that we will not experience losses in dealings with other parties.

We may in the future encounter increased costs related to, and lack of availability of, insurance.

Over the last several years, as the scale and scope of our business activities has expanded, the breadth and depth of available insurance markets has contracted. Some of this may be attributable to the events of September 11, 2001 and the effects of hurricanes along the Gulf Coast during 2005, which adversely impacted the availability and costs of certain types of coverage. We can give no assurance that we will be able to maintain adequate insurance in the future at rates we consider reasonable. The occurrence of a significant event not fully insured could materially and adversely affect our operations and financial condition.

Marine transportation of crude oil and refined product has inherent operating risks.

Our gathering and marketing operations include purchasing crude oil that is carried on third-party tankers. Our waterborne cargoes of crude oil are at risk of being damaged or lost because of events such as marine disaster, bad weather, mechanical failures, grounding or collision, fire, explosion, environmental accidents, piracy, terrorism and political instability. Such occurrences could result in death or injury to persons, loss of property or environmental damage, delays in the delivery of cargo, loss of revenues from or termination of charter contracts, governmental fines, penalties or restrictions on conducting business, higher insurance rates and damage to our reputation and customer relationships generally. Although certain of these risks may be covered under our insurance program, any of these circumstances or events could increase our costs or lower our revenues.

In instances in which cargoes are purchased FOB (title transfers when the oil is loaded onto a vessel chartered by the purchaser) the contract to purchase is typically made prior to the vessel being chartered. In such circumstances we take the risk of higher than anticipated charter costs. We are also exposed to increased transit time and unanticipated demurrage charges, which involve extra payment to the owner of a vessel for delays in offloading, circumstances that we may not control.

Maritime claimants could arrest the vessels carrying our cargoes.

Crew members, suppliers of goods and services to a vessel, other shippers of cargo and other parties may be entitled to a maritime lien against that vessel for unsatisfied debts, claims or damages. In many jurisdictions, a maritime lienholder may enforce its lien by arresting a vessel through foreclosure proceedings. The arrest or attachment of a vessel carrying a cargo of our oil could substantially delay our shipment.

In addition, in some jurisdictions, under the “sister ship” theory of liability, a claimant may arrest both the vessel that is subject to the claimant’s maritime lien and any “associated” vessel, which is any vessel owned or controlled by the same owner. Claimants could try to assert “sister ship” liability against one vessel carrying our cargo for claims relating to a vessel with which we have no relation.

We are dependent on use of a third-party marine dock for delivery of waterborne crude oil into our storage and distribution facilities in the Los Angeles basin.

A portion of our storage and distribution business conducted in the Los Angeles basin (acquired in connection with the Pacific acquisition) is dependent on our ability to receive waterborne crude oil, a major portion of which is presently being received through dock facilities operated by Shell Oil Products in the Port of Long Beach. We are currently a hold-over tenant with respect to such facilities. If we are unable to renew the agreement that allows us to utilize these dock facilities, and if other alternative dock access cannot be arranged, the volumes of crude oil that we presently receive from our customers in the Los Angeles basin may be reduced, which could result in a reduction of facilities segment revenue and cash flow.

The terms of our indebtedness may limit our ability to borrow additional funds or capitalize on business opportunities.

As of December 31, 2006, our total outstanding long-term debt was approximately $2.6 billion. Various limitations in certain of our debt instruments may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

Changes in currency exchange rates could adversely affect our operating results.

Because we conduct operations in Canada, we are exposed to currency fluctuations and exchange rate risks that may adversely affect our results of operations.

Terrorist attacks aimed at our facilities could adversely affect our business.

Since the September 11, 2001 terrorist attacks, the U.S. government has issued warnings that energy assets, specifically the nation's pipeline infrastructure, may be future targets of terrorist organizations. These developments will subject our operations to increased risks. Any future terrorist attack that may target our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business.

An impairment of goodwill could reduce our earnings.

We recorded a significant amount of goodwill upon completion of our merger with Pacific, but our preliminary estimate is subject to change pending the completion of an independent appraisal. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the acquired tangible and separately measurable intangible net assets. U.S. generally accepted accounting principles, or GAAP, requires us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. If we were to determine that any of our remaining balance of goodwill was impaired, we would be required to take an immediate charge to earnings with a corresponding reduction of partners' equity and increase in balance sheet leverage as measured by debt to total capitalization.

Our natural gas storage facilities are new and have limited operating history.

Although we believe that our operating natural gas storage facilities are designed substantially to meet our contractual obligations with respect to injection and withdrawal volumes and specifications, the facilities are new and have a limited operating history. If we fail to receive or deliver natural gas at contracted rates, or cannot deliver natural gas consistent with contractual quality specifications, we could incur significant costs to maintain compliance with our contracts.

We have a limited history of operating natural gas storage facilities and transporting, storing and marketing refined products.

Although many aspects of the natural gas storage and refined products industries are similar to our crude oil operations, our current management has little experience in operating natural gas storage facilities or in the refined products business. There are significant risks and costs inherent in our efforts to engage in these operations, including the risk that our new lines of business may not be profitable and that we might not be able to operate them or implement our operating policies and strategies successfully.

The devotion of capital, management time and other resources to natural gas storage and refined products operations could adversely affect our existing business. Entering into the natural gas storage and refined products industries may require substantial changes, including acquisition costs, capital development expenditures, adding skilled management and employees and realigning our current organization to reflect these new lines of business.

Entering into the natural gas storage industry will require an investment in personnel and assets and the assumption of risks that may be greater than we have previously assumed.

Federal, state or local regulatory measures could adversely affect our natural gas storage business.

Our natural gas storage operations are subject to federal, state and local regulation. Specifically, our natural gas storage facilities and related assets are subject to regulation by the FERC, the Michigan Public Service Commission and various Louisiana state agencies. Our facilities essentially have market-based rate authority from such agencies. Any loss of market-based rate authority could have an adverse impact on our revenues associated with providing storage services. In addition, failure to comply with applicable regulations under the Natural Gas Act, and certain other state laws could result in the imposition of administrative, civil and criminal remedies.

Our gas storage business depends on third party pipelines to transport natural gas.

We depend on third party pipelines to move natural gas for our customers to and from our facilities. Any interruption of service on the pipelines or lateral connections or adverse change in the terms and conditions of service could have a material adverse effect on our ability, and the ability of our customers, to transport natural gas to and from our facilities, and could have a corresponding material adverse effect on our storage revenues. In addition, the rates charged by the interconnected pipeline for transportation to and from our facilities could affect the utilization and value of our storage services. Significant changes in the rates charged by the pipeline or the rates charged by other pipelines with which the interconnected pipelines compete could also have a material adverse effect on our storage revenues.

We may not be able to retain existing natural gas storage customers or acquire new customers, which would reduce our revenues and limit our future profitability.

The renewal or replacement of existing contracts with our customers at rates sufficient to maintain or exceed current or anticipated revenues and cash flows depends on a number of factors beyond our control, including competition from other storage providers and the supply of and demand for natural gas in the markets we serve. The inability to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

Joint venture structures can create operational difficulties.

Our natural gas storage operations are conducted through PAA/Vulcan, a joint venture between us and a subsidiary of Vulcan Capital. We are also engaged in a joint venture arrangement with Settoon Towing.

As with any joint venture arrangement, differences in views among the joint venture participants may result in delayed decisions or in failures to agree on major matters, potentially adversely affecting the business and operations of the joint ventures and in turn our business and operations.

Risks Inherent in an Investment in Plains All American Pipeline, L.P.

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

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates, including officers and directors of the general partner, for all expenses incurred on our behalf. The reimbursement of expenses and the payment of fees could adversely affect our ability to make distributions. The general partner has sole discretion to determine the amount of these expenses. In addition, our general partner and its affiliates may provide us services for which we will be charged reasonable fees as determined by the general partner.

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves.

Because distributions on the common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of the general partner. Cash distributions are dependent 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. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

Unitholders may not be able to remove our general partner even if they wish to do so.

Our general partner manages and operates the Partnership. Unlike the holders of common stock in a corporation, unitholders will have only limited voting rights on matters affecting our business. Unitholders have no right to elect the general partner or the directors of the general partner on an annual or any other basis.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have little practical ability to remove our general partner or otherwise change its management. Our general partner may not be removed except upon the vote of the holders of at least 662/3% of our outstanding units (including units held by our general partner or its affiliates). Because the owners of our general partner, along with directors and executive officers and their affiliates, own a significant percentage of our outstanding common units, the removal of our general partner would be difficult without the consent of both our general partner and its affiliates.

In addition, the following provisions of our partnership agreement may discourage a person or group from attempting to remove our general partner or otherwise change our management:

- generally, if a person acquires 20% or more of any class of units then outstanding other than from our general partner or its affiliates, the units owned by such person cannot be voted on any matter; and
- limitations upon the ability of unitholders to call meetings or to acquire information about our operations, as well as other limitations upon the unitholders' ability to influence the manner or direction of management.

As a result of these provisions, the price at which the common units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

We may issue additional common units without unitholder approval, which would dilute a unitholder's existing ownership interests.

Our general partner may cause us to issue an unlimited number of common units, without unitholder approval (subject to applicable NYSE rules). We may also issue at any time an unlimited number of equity securities ranking junior or senior to the common units without unitholder approval (subject to applicable NYSE rules). The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- an existing unitholder's proportionate ownership interest in the Partnership will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Our general partner has a limited call right that may require unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own 80% or more of the common units, the general partner will have the right, but not the obligation, which it may assign to any of its affiliates, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price generally equal to the then current market price of the common units. As a result, unitholders may be required to sell their common units at a time when they may not desire to sell them or at a price that is less than the price they would like to receive. They may also incur a tax liability upon a sale of their common units.

Unitholders may not have limited liability if a court finds that unitholder actions constitute control of our business.

Under Delaware law, a unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the "control" of our business.

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner.

In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

Conflicts of interest could arise among our general partner and us or the unitholders.

These conflicts may include the following:

- we do not have any employees and we rely solely on employees of the general partner or, in the case of Plains Marketing Canada, employees of PMC (Nova Scotia) Company;
- under our partnership agreement, we reimburse the general partner for the costs of managing and for operating the partnership;
- the amount of cash expenditures, borrowings and reserves in any quarter may affect available cash to pay quarterly distributions to unitholders;
- the general partner tries to avoid being liable for partnership obligations. The general partner is permitted to protect its assets in this manner by our partnership agreement. Under our partnership agreement the general partner would not breach its fiduciary duty by avoiding liability for partnership obligations even if we can obtain more favorable terms without limiting the general partner's liability; under our partnership agreement, the general partner may pay its affiliates for any services rendered on terms fair and reasonable to us. The general partner may also enter into additional contracts with any of its affiliates on behalf of us. Agreements or contracts between us and our general partner (and its affiliates) are not necessarily the result of arms length negotiations; and
- the general partner would not breach our partnership agreement by exercising its call rights to purchase limited partnership interests or by assigning its call rights to one of its affiliates or to us.

The control of our general partner may be transferred to a third party without unitholder consent. A change of control may result in defaults under certain of our debt instruments and the triggering of payment obligations under compensation arrangements.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the general partner of our general partner from transferring its general partnership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers with its own choices and to control their decisions and actions.

In addition, a change of control would constitute an event of default under the indentures governing certain issues of our senior notes and under our revolving credit agreement. An event of default under certain of our indentures could require us to make an offer to purchase the senior notes issued thereunder at a purchase price equal to 101% of the aggregate principal amount, plus accrued and unpaid interest, if any, to the date of purchase. During the continuance of an event of default under our revolving credit agreement, the administrative agent may terminate any outstanding commitments of the lenders to extend credit to us under our revolving credit facility and/or declare all amounts payable by us under our revolving credit facility immediately due and payable. A change of control also may trigger payment obligations under various compensation arrangements with our officers.

Risks Related to an Investment in Our Debt Securities

The right to receive payments on our outstanding debt securities and subsidiary guarantees is unsecured and will be effectively subordinated to our existing and future secured indebtedness as well as to any existing and future indebtedness of our subsidiaries that do not guarantee the notes.

Our debt securities are effectively subordinated to claims of our secured creditors and the guarantees are effectively subordinated to the claims of our secured creditors as well as the secured creditors of our subsidiary guarantors. Although substantially all of our operating subsidiaries, other than minor subsidiaries and those regulated by the CPUC, have guaranteed such debt securities, the guarantees are subject to release under certain circumstances, and we may have subsidiaries that are not guarantors. In that case, the debt securities would be effectively subordinated to the claims of all creditors, including trade creditors and tort claimants, of our subsidiaries that are not guarantors. In the event of the insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up of the business of a subsidiary that is not a guarantor, creditors of that subsidiary would generally have the right to be paid in full before any distribution is made to us or the holders of the debt securities.

Our leverage may limit our ability to borrow additional funds, comply with the terms of our indebtedness or capitalize on business opportunities.

Our leverage is significant in relation to our partners' capital. At December 31, 2006, our total outstanding long-term debt and short-term debt under our revolving credit facility was approximately $3.6 billion. We will be prohibited from making cash distributions during an event of default under any of our indebtedness. Various limitations in our credit facilities may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

Our leverage could have important consequences to investors in our debt securities. We will require substantial cash flow to meet our principal and interest obligations with respect to the notes and our other consolidated indebtedness. Our ability to make scheduled payments, to refinance our obligations with respect to our indebtedness or our ability to obtain additional financing in the future will depend on our financial and operating performance, which, in turn, is subject to prevailing economic conditions and to financial, business and other factors. We believe that we will have sufficient cash flow from operations and available borrowings under our bank credit facility to service our indebtedness, although the principal amount of the notes will likely need to be refinanced at maturity in whole or in part. However, a significant downturn in the hydrocarbon industry or other development adversely affecting our cash flow could materially impair our ability to service our indebtedness. If our cash flow and capital resources are insufficient to fund our debt service obligations, we may be forced to refinance all or portion of our debt or sell assets. We can give no assurance that we would be able to refinance our existing indebtedness or sell assets on terms that are commercially reasonable. In addition, if one or more rating agencies were to lower our debt ratings, we could be required by some of our counterparties to post additional collateral, which would reduce our available liquidity and cash flow.

Our leverage may adversely affect our ability to fund future working capital, capital expenditures and other general partnership requirements, future acquisition, construction or development activities, or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness. Our leverage may also make our results of operations more susceptible to adverse economic and industry conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

A court may use fraudulent conveyance considerations to avoid or subordinate the subsidiary guarantees.

Various applicable fraudulent conveyance laws have been enacted for the protection of creditors. A court may use fraudulent conveyance laws to subordinate or avoid the subsidiary guarantees of our debt securities issued by any of our subsidiary guarantors. It is also possible that under certain circumstances a court could hold that the direct obligations of a subsidiary guaranteeing our debt securities could be superior to the obligations under that guarantee.

A court could avoid or subordinate the guarantee of our debt securities by any of our subsidiaries in favor of that subsidiary's other debts or liabilities to the extent that the court determined either of the following were true at the time the subsidiary issued the guarantee:

- that subsidiary incurred the guarantee with the intent to hinder, delay or defraud any of its present or future creditors or that subsidiary contemplated insolvency with a design to favor one or more creditors to the total or partial exclusion of others; or
- that subsidiary did not receive fair consideration or reasonable equivalent value for issuing the guarantee and, at the time it issued the guarantee, that subsidiary:
  - — was insolvent or rendered insolvent by reason of the issuance of the guarantee;
  - — was engaged or about to engage in a business or transaction for which the remaining assets of that subsidiary constituted unreasonably small capital; or
  - — intended to incur, or believed that it would incur, debts beyond its ability to pay such debts as they matured.

The measure of insolvency for purposes of the foregoing will vary depending upon the law of the relevant jurisdiction. Generally, however, an entity would be considered insolvent for purposes of the foregoing if the sum of its debts, including contingent liabilities, were greater than the fair saleable value of all of its assets at a fair valuation, or if the present fair saleable value of its assets were less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they become absolute and matured.

Among other things, a legal challenge of a subsidiary's guarantee of our debt securities on fraudulent conveyance grounds may focus on the benefits, if any, realized by that subsidiary as a result of our issuance of our debt securities. To the extent a subsidiary's guarantee of our debt securities is avoided as a result of fraudulent conveyance or held unenforceable for any other reason, the holders of our debt securities would cease to have any claim in respect of that guarantee.

The ability to transfer our debt securities may be limited by the absence of a trading market.

We do not currently intend to apply for listing of our debt securities on any securities exchange or stock market. The liquidity of any market for our debt securities will depend on the number of holders of those debt securities, the interest of securities dealers in making a market in those debt securities and other factors. Accordingly, we can give no assurance as to the development or liquidity of any market for the debt securities.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

We are a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the ownership interests in our subsidiaries. As a result, our ability to make required payments on our debt securities depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit facilities and applicable state partnership laws and other laws and regulations. Pursuant to the credit facilities, we may be required to establish cash reserves for the future payment of principal and interest on the amounts outstanding under our credit facilities. If we are unable to obtain the funds necessary to pay the principal amount at maturity of the debt securities, or to repurchase the debt securities upon the occurrence of a change of control, we may be required to adopt one or more alternatives, such as a refinancing of the debt securities. We cannot assure you that we would be able to refinance the debt securities.

We do not have the same flexibility as other types of organizations to accumulate cash, which may limit cash available to service our debt securities or to repay them at maturity.

Unlike a corporation, our partnership agreement requires us to distribute, on a quarterly basis, 100% of our available cash to our unitholders of record and our general partner. Available cash is generally all of our cash receipts adjusted for cash distributions and net changes to reserves. Our general partner will determine the amount and timing of such distributions and has broad discretion to establish and make additions to our reserves or the reserves of our operating partnerships in amounts the general partner determines in its reasonable discretion to be necessary or appropriate:

- to provide for the proper conduct of our business and the businesses of our operating partnerships (including reserves for future capital expenditures and for our anticipated future credit needs);
- to provide funds for distributions to our unitholders and the general partner for any one or more of the next four calendar quarters; or
- to comply with applicable law or any of our loan or other agreements.

Although our payment obligations to our unitholders are subordinate to our payment obligations to debtholders, the value of our units will decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue equity to recapitalize.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. and Canadian federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation or if we become subject to a material amount of entity-level taxation for state tax purposes, it would substantially reduce the amount of cash available to pay distributions and our debt obligations.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Because a tax would be imposed upon us as a corporation, the cash available for distributions or to pay our debt obligations would be substantially reduced.

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. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. For example, we will be subject to a new entity level tax on the portion of our income that is generated in Texas beginning in our tax year ending in 2007. Specifically, the Texas margin tax will be imposed at a maximum effective rate of 0.7% of our gross income apportioned to Texas. Imposition of such a tax upon us as an entity by Texas or any other state will reduce the cash available for distributions or to pay our debt obligations.

Proposed changes in Canadian tax law could subject our Canadian subsidiaries to entity-level tax, which would reduce the amount of cash available to pay distributions and our debt obligations.

In response to the perceived proliferation of “income trusts” in Canada, the Canadian government has issued proposed regulations that impose entity-level taxes on certain types of flow-through entities. At this point, final regulations have not been issued and it is not clear what impact the final regulations will have on our Canadian subsidiaries. Any entity-level taxation of our Canadian subsidiaries would reduce the cash available for distributions or to pay our debt obligations.

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

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

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution or debt service.

We have not requested a ruling from the IRS with respect to any matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not concur with our counsel's conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for common units and the price at which they trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will be borne by us and directly or indirectly by the unitholders and the general partner because the costs will reduce our cash available for distribution or debt service.

Our unitholders may be required to pay taxes 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 that could be different in amount than the cash we distribute, they 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 do not receive any cash distributions from us. 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 their share of our taxable income.

Tax gain or loss on disposition of common units could be different than expected.

If our unitholders sell their common units, they will recognize gain or loss equal to the difference between the amount realized and their tax basis in those common units. Prior distributions in excess of the total net taxable income allocated to a unitholder for a common unit, which decreased the unitholder's tax basis in that common unit, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price the unitholder receives is less than the unitholder's original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to the unitholder. Should the IRS successfully contest some positions we take, the unitholder could recognize more gain on the sale of units than would be the case under those positions, without the benefit of decreased income in prior years. Also, if a unitholder sells units, the unitholder 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 common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as individual retirement accounts (IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income.

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

Because we cannot match transferors and transferees of common units and because of other reasons, we have adopted depreciation and amortization positions that do not conform with all aspects of the 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 a unitholder's sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to a unitholder's tax return.

Our unitholders will likely be subject to foreign, state and local taxes and tax return filing requirements in jurisdictions where they do not live as a result of an investment in our units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including foreign taxes, 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 and in which they do not reside. We own property and conduct business in Canada and in most states in the United States. Unitholders will be required to file Canadian federal income tax returns and to pay Canadian federal and provincial income taxes in respect of our Canadian source income earned through partnership entities. A unitholder may also be required to file state and local income tax returns and pay state and local income taxes in many or all of the jurisdictions in which we conduct business or own property. Further, unitholders may be subject to penalties for failure to comply with those requirements. It is our unitholders' responsibility to file all United States federal, state, local and foreign tax returns.

Unresolved Staff Comments

None.

Legal Proceedings

Pipeline Releases. In January 2005 and December 2004, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In late December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains, the U.S. Environmental Protection Agency (the "EPA"), the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 980 and 4,200 barrels were recovered from the two respective sites. The unrecovered oil was removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $3.0 million to $3.5 million. In cooperation with the appropriate state and federal environmental authorities, we have substantially completed our work with respect to site restoration, subject to some ongoing remediation at the Pecos River site. EPA has referred these two crude oil releases, as well as several other smaller releases, to the U.S. Department of Justice (the "DOJ") for further investigation in connection with a possible civil penalty enforcement action under the Federal Clean Water Act. We are cooperating in the investigation. Our assessment is that it is probable we will pay penalties related to the two releases. We have accrued the estimated loss contingency, which is included in the estimated aggregate costs set forth above. It is reasonably possible that the loss contingency may exceed our estimate with respect to penalties assessed by the DOJ; however, we have no indication from EPA or the DOJ of what penalties might be sought. As a result, we are unable to estimate the range of a reasonably possible loss contingency in excess of our accrual.

On November 15, 2006, we completed the Pacific acquisition. The following is a summary of the more significant matters that relate to Pacific, its assets or operations.

The People of the State of California v. Pacific Pipeline System, LLC ("PPS"). In March 2005, a release of approximately 3,400 barrels of crude oil occurred on Line 63, subsequently acquired by us in the Pacific merger.

The release occurred when Line 63 was severed as a result of a landslide caused by heavy rainfall in the Pyramid Lake area of Los Angeles County. As of December 31, 2006, $26 million of remediation costs had been incurred. We estimate additional remediation costs of approximately $1 to $2 million, substantially all of which we expect to incur before June 2007. We anticipate that the majority of costs associated with this release will be covered under a pre-existing PPS pollution liability insurance policy.

In March 2006, PPS, a subsidiary acquired in the Pacific merger, was served with a four count misdemeanor criminal action in the Los Angeles Superior Court Case No. 6NW01020, which alleges the violation by PPS of two strict liability statutes under the California Fish and Game Code for the unlawful deposit of oil or substances harmful to wildlife into the environment, and violations of two sections of the California Water Code for the willful and intentional discharge of pollution into state waters. The fines that can be assessed against PPS for the violations of the strict liability statutes are based, in large measure, on the volume of unrecovered crude oil that was released into the environment, and, therefore, the maximum state fine that can be assessed is estimated to be approximately $1,100,000, in the aggregate. This amount is subject to a downward adjustment with respect to actual volumes of recovered crude oil, and the State of California has the discretion to further reduce the fine after considering other mitigating factors. Because of the uncertainty associated with these factors, the final amount of the fine that will be assessed for the strict liability offenses cannot be ascertained. We will defend against these charges. In addition to these fines, the State of California has indicated that it may seek to recover approximately $150,000 in natural resource damages against PPS in connection with this matter. The mitigating factors may also serve as a basis for a downward adjustment of the natural resource damages amount. We believe that certain of the alleged violations are without merit and intend to defend against them, and that mitigating factors should apply.

In December 2006 we were informed that the EPA may be intending to refer this matter to the DOJ for the initiation of proceedings to assess civil penalties against PPS. The DOJ has accepted the referral. We understand that the maximum permissible penalty that the EPA could assess under relevant statutes would be approximately $3.7 million. We believe that several mitigating circumstances and factors exist that could substantially reduce the penalty, and intend to pursue discussions with the EPA regarding such mitigating circumstances and factors. Because of the uncertainty associated with these factors, the final amount of the penalty that will be assessed by the EPA cannot be ascertained. Discussions with the DOJ to resolve this matter have commenced.

Kosseff v. Pacific Energy, et al, case no. BC 3544016. On June 15, 2006, a lawsuit was filed in the Superior court of California, County of Los Angeles, in which the plaintiff alleged that he was a unitholder of Pacific and he sought to represent a class comprising all of Pacific's unitholders. The complaint named as defendants Pacific and certain of the officers and directors of Pacific's general partner, and asserted claims of self-dealing and breach of fiduciary duty in connection with the pending merger with us and related transactions. The plaintiff sought injunctive relief against completing the merger or, if the merger was completed, rescission of the merger, other equitable relief, and recovery of the plaintiff's costs and attorneys' fees. On September 14, 2006, Pacific and the other defendants entered into a memorandum of settlement with the plaintiff to settle the lawsuit. As part of the settlement, Pacific and the other defendants deny all allegations of wrongdoing and express willingness to settle the lawsuit solely because the settlement would eliminate the burden and expense of further litigation. The settlement is subject to customary conditions, including court approval. As part of the settlement, we (as successor to Pacific) will pay $0.5 million to the plaintiff's counsel for their fees and expenses, and incur the cost of mailing materials to former Pacific unitholders. If finally approved by the court, the settlement will resolve all claims that were or could have been brought on behalf of the proposed settlement class in the actions being settled, including all claims relating to the merger, the merger agreement and any disclosure made by Pacific in connection with the merger. The settlement did not change any of the terms or conditions of the merger.

Air Quality Permits. In connection with the Pacific merger, we acquired Pacific Atlantic Terminals LLC ("PAT"), which is now one of our subsidiaries. PAT owns crude oil and refined products terminals in northern California. In the process of integrating PAT's assets into our operations, we identified certain aspects of the operations at the terminals that appeared to be out of compliance with specifications under the relevant air quality permit. We conducted a prompt review of the circumstances and self-reported the apparent historical occurrences of non-compliance to the Bay Area Air Quality Management District. We are cooperating with the District's review of these matters.

General. We, in the ordinary course of business, are a claimant and/or a defendant in various legal proceedings. To the extent we are able to assess the likelihood of a negative outcome for these proceedings, our assessments of such likelihood range from remote to probable. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue the estimated amount. We do not believe that the outcome of these legal proceedings, individually and in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Submission of Matters to a Vote of Security Holders

On November 9, 2006, the Partnership held a special meeting of its unitholders for the following purposes:

1. To consider and vote upon the approval and adoption of the Agreement and Plan of Merger dated as of June 11, 2006 by and among the Partnership, Plains AAP, L.P., Plains All American GP LLC, Pacific, Pacific Energy Management LLC and Pacific Energy GP, LP, as it may be amended from time to time (the "Merger Agreement"); and

2. To consider and vote upon the approval of the issuance of our common units to the common unitholders of Pacific (other than LB Pacific, LP), as provided in the Merger Agreement.

Holders of over 65% of our outstanding common units voted in favor of both proposals. The voting results were as follows:

Matter	Votes Cast For	Votes Cast Against	Votes Cast Abstain	Broker Non-
Approve Merger Agreement	52,832,920	297,858	261,365	n/a
Approve Issuance of Units Pursuant to Merger Agreement	52,733,280	373,438	285,425	n/a