PLAINS ALL AMERICAN PIPELINE LP
Form 10-K
March 01, 2007

Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2006

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**76-0582150**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

333 Clay Street, Suite 1600, Houston, Texas 77002
(Address of principal executive offices) (Zip Code)

(713) 646-4100
(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Units	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):
Large Accelerated Filer þ Accelerated Filer o Non-Accelerated Filer o

Indicate by check mark if the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

The aggregate value of the Common Units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Common Units outstanding, for this purpose, as if they may be affiliates of the registrant) was approximately $2.7 billion on June 30, 2006, based on $43.67 per unit, the closing price of the Common Units as reported on the New York Stock Exchange on such date.

At February 20, 2007, there were outstanding 109,405,178 Common Units.

DOCUMENTS INCORPORATED BY REFERENCE

NONE

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FORM 10-K 2006 ANNUAL REPORT

Table of Contents

Certification of PFO Pursuant to Section 1350

Table of Contents

FORWARD-LOOKING STATEMENTS

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements identified by the words anticipate, believe, estimate, expect, plan, inten forecast, and similar expressions and statements regarding our business strategy, plans and objectives of our management for future operations. The absence of these words, however, does not mean that the statements are not forward-looking. These statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions. Certain factors could cause actual results to differ materially from results anticipated in the forward-looking statements. These factors include, but are not limited to:

our failure to successfully integrate the business operations of Pacific Energy Partners L.P. (Pacific) or our failure to successfully integrate any future acquisitions;

the failure to realize the anticipated cost savings, synergies and other benefits of the merger with Pacific;

the success of our risk management activities;

environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;

maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;

abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline systems;

failure to implement or capitalize on planned internal growth projects;

the availability of adequate third party production volumes for transportation and marketing in the areas in which we operate, and other factors that could cause declines in volumes shipped on our pipelines by us and third party shippers;

fluctuations in refinery capacity in areas supplied by our mainlines, and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transmission throughput requirements;

the availability of, and our ability to consummate, acquisition or combination opportunities;

our access to capital to fund additional acquisitions and our ability to obtain debt or equity financing on satisfactory terms;

future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;

unanticipated changes in crude oil market structure and volatility (or lack thereof);

the impact of current and future laws, rulings and governmental regulations;

the effects of competition;

continued creditworthiness of, and performance by, our counterparties;

interruptions in service and fluctuations in tariffs or volumes on third-party pipelines;

increased costs or lack of availability of insurance;

fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our Long-Term Incentive Plans;

the currency exchange rate of the Canadian dollar;

shortages or cost increases of power supplies, materials or labor;

weather interference with business operations or project construction;

risks related to the development and operation of natural gas storage facilities;

general economic, market or business conditions; and

other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products.

Other factors described elsewhere in this document, or factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read Risks Related to Our Business discussed in Item 1A. Risk Factors. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Table of Contents

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 sub 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

Table of Contents

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.

Table of Contents

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	Regional 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

Table of Contents

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

Table of Contents

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

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.

13

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, (Barrels in thousands)				
	2006	**2005**	**2004**	**2003**	**2002**
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.

Table of Contents

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.

Table of Contents

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		3.3 million barrels

	Crude oil marine and storage terminals in Mobile, Alabama	
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.

Table of Contents

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.

Table of Contents

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

28

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.

Table of Contents

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

Table of Contents

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