PLAINS ALL AMERICAN PIPELINE LP
Form 10-K
February 29, 2008

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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, 2007

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, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer þ Accelerated Filer o Non-Accelerated Filer o (Do not check if a smaller reporting company) Smaller Reporting Company o

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

The aggregate market 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 $6.4 billion on June 29, 2007, based on $63.65 per unit, the closing price of the Common Units as reported on the New York Stock Exchange on such date.

At February 20, 2008, there were outstanding 115,981,676 Common Units.

DOCUMENTS INCORPORATED BY REFERENCE
NONE

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FORM 10-K 2007 ANNUAL REPORT

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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, intend 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:

- failure to implement or capitalize on planned internal growth projects;
- 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;
- shortages or cost increases of power supplies, materials or labor;
- 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 transportation 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;
- successful integration and 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;

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.

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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.

PART I

Items 1 and 2. *Business and Properties*

General

Plains All American Pipeline, L.P. is a Delaware limited partnership formed in 1998. Our operations are conducted directly and indirectly through our primary operating subsidiaries. As used in this Form 10-K, the terms Partnership, Plains, we, us, our, ours and similar terms refer to Plains All American Pipeline, L.P. and its subsidiaries, unless 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 are also involved in the development and operation of natural gas storage facilities.

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing.

Transportation Segment

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

As of December 31, 2007, 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 crude oil and refined products pipelines and gathering systems;
- 23 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;
- 83 trucks and 364 trailers; and
- 62 transport and storage barges and 32 transport tugs through our interest in Settoon Towing, LLC (Settoon Towing).

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

Facilities Segment

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.

As of December 31, 2007, we owned and employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 47 million barrels of crude oil and refined products capacity primarily at our terminalling and storage locations;

- approximately 6 million barrels of LPG capacity; 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 24,000 barrels per day.

At year-end 2007, we were in the process of constructing approximately 10 million barrels of additional above-ground crude oil and refined product terminalling and storage facilities and approximately 1 million barrels of underground LPG storage capacity, the majority of which we expect to place in service during 2008.

Our facilities segment also includes our equity earnings from our investment in PAA/Vulcan. At December 31, 2007, PAA/Vulcan owned and operated approximately 26 billion cubic feet of underground storage capacity and was constructing an additional 24 billion cubic feet of underground natural gas storage capacity, which is expected to be placed in service in stages over the next several years.

Marketing Segment

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 and the seasonal storage of LPG;

- 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

- 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.

We believe our marketing activities are counter-cyclically balanced to produce a stable baseline of results in a variety of market conditions, while at the same time providing upside potential associated with opportunities inherent in volatile market conditions. This is achieved by utilizing storage facilities at major interchange and terminalling locations and various hedging strategies. See Crude Oil Volatility; Counter-Cyclical Balance; Risk Management.

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 outright commodity price changes.

In addition to substantial working inventories and working capital associated with its merchant activities, as of December 31, 2007, our marketing segment also owned crude oil and LPG classified as long-term assets and a variety of owned or leased physical assets throughout the United States and Canada, including approximately:

- 8 million barrels of crude oil and LPG linefill in pipelines owned by the Partnership;

- 1 million barrels of crude oil and LPG linefill in pipelines owned by third parties;

- 540 trucks and 710 trailers; and

- 1,400 railcars.

In connection with its operations, the marketing segment secures transportation and facilities services from our 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 or at the same rates as those charged to third-party shippers. 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.

Although certain activities in our marketing segment are affected by seasonal aspects, in general, seasonality does not have a material impact on our operations and segments.

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. Toward this end, we endeavor to address regional supply and demand imbalances for crude oil, refined products and LPG in the United States and Canada by combining the strategic location and 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 products 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 optimize our presence in the waterborne importation of foreign crude oil;
- expanding our presence in the refined products supply and marketing sector;
- selectively pursuing strategic and accretive acquisitions of crude oil, refined products and LPG transportation, terminalling, storage and marketing assets and businesses that complement our existing asset base and distribution capabilities; and
- using our terminalling and storage assets in conjunction with our marketing activities to capitalize on inefficient energy markets and 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. PAA/Vulcan s 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-adjusted EBITDA multiple of approximately 3.5x (adjusted EBITDA is earnings before interest, taxes, depreciation and amortization, equity compensation 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)); and

an average adjusted 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, refined products and LPG. The crude oil, refined products and LPG purchased in these transactions are hedged. 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. We also incur short-term debt for New York Mercantile Exchange (NYMEX) and IntercontinentalExchange (ICE) margin requirements.

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 from capital expansion projects to adjusted EBITDA. At December 31, 2007, our long-term debt-to-total capitalization ratio was approximately 43% and our adjusted EBITDA-to-interest coverage multiple on a trailing twelve month basis was above our targeted metric. Based on our December 31, 2007 long-term debt balance and the midpoint of our guidance for 2008 furnished in a Form 8-K dated February 13, 2008, our long-term debt-to-adjusted-EBITDA multiple would be approximately 3.3 times.

Credit Rating

As of February 2008, our senior unsecured ratings with Standard & Poor s and Moody s Investment Services were BBB-, stable outlook, and Baa3, stable outlook, respectively, both of which are considered investment grade ratings. We have targeted the attainment of stronger investment grade ratings of mid to high-BBB and Baa categories for Standard & Poor s and Moody s Investment Services, respectively. However, our current ratings might not remain in effect for any given period of time, we might not be able to attain the higher ratings we have targeted and one or both of these ratings might 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 to successfully execute our principal business strategy:

Many of our transportation segment and facilities segment assets are strategically located and operationally flexible. 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 crude oil marketing activities are counter-cyclically balanced. We believe the variety 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 ten years, we have completed and integrated approximately 50 acquisitions with an aggregate purchase price of approximately $5.3 billion. We have also implemented internal expansion capital projects totaling over $1.3 billion. In addition, we believe we have significant resources to finance future strategic expansion and acquisition opportunities. As of December 31, 2007, we had approximately $1.0 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 large capitalization midstream master limited partnerships.

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, and an average of more than 15 years with us or our predecessors and affiliates. In addition, through their ownership of

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common units, indirect interests in our general partner, grants of phantom units and the Class B units in Plains AAP, L.P., our management team has a vested interest in our continued success.

We believe these competitive strengths will aid 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 to acquire and operate the midstream crude oil businesses and assets of a predecessor entity and completed our initial public offering in 1998. Our 2% general partner interest is held by PAA GP LLC, a Delaware limited liability company, whose sole member is 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. References to our general partner, as the context requires, include any or all of PAA GP LLC, 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. Plains All American GP LLC 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.

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

Partnership Structure

(1) Based on Form 4 filings for executive officers and directors, 13D filings for Paul G. Allen and Richard Kayne and other information believed to be reliable for the remaining investors, this group, or affiliates of such investors, owns approximately 26 million limited partner units, representing approximately 22% of all outstanding units.

(2) Incentive Distribution Rights (IDRs). See Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities for discussion of our general partner s incentive distribution rights.

(3) The Partnership holds 100% direct and indirect ownership interests in consolidated operating subsidiaries including, but not limited to, Plains Pipeline, L.P., Plains Marketing, L.P., Plains LPG Services, L.P., Pacific Energy Partners LLC, PMC (Nova Scotia) Company and Plains Marketing Canada, L.P.

(4) The Partnership holds direct and indirect equity interests in unconsolidated entities including, but not limited to, PAA/Vulcan Gas Storage, LLC and Settoon Towing LLC.

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, LPG assets and natural gas storage 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, 2007, we have completed approximately 50 acquisitions for a cumulative purchase price of approximately $5.3 billion.

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

Acquisition	**Date**	**Description**	**Approximate Purchase Price**
Tirzah Storage Facility	Oct-2007	Liquefied Petroleum Gas storage facility	$54
Bumstead Storage Facility	Jul-2007	Liquefied Petroleum Gas storage facility	$52
Pacific Energy Partners LP (Pacific)	Nov-2006	Merger of Pacific Energy Partners with and into the Partnership	$2,456
El Paso to Albuquerque Products Pipeline Systems	Sep-2006	Three refined products pipeline systems	$66
CAM/BOA/HIPS Crude oil systems	Jul-2006	64.35% interest in the Clovelly-to-Meraux (CAM) Pipeline system; 100% interest in the Bay Marchand-to-Ostrica-toAlliance (BOA) system and various interests in the High Island Pipeline System (HIPS)(1)	$130
Andrews Petroleum and Lone Star Trucking	Apr-2006	Isomerization, fractionation, marketing and transportation services	$220
South Louisiana Gathering and Transportation Assets (SemCrude)	Apr-2006	Crude oil gathering and transportation assets, including inventory and related contracts in South Louisiana	$129
Investment in Natural Gas Storage Facilities	Sep-2005	Joint venture with Vulcan Gas Storage LLC to develop and operate natural gas storage facilities	$125(2)
Link Energy LLC	Apr-2004	North American crude oil and pipeline operations of Link Energy, LLC (Link)	$332
Capline and Capwood Pipeline Systems	Mar-2004	An approximate 22% undivided joint interest in the Capline Pipeline System and an approximately 76% undivided joint interest in the Capwood Pipeline System	$159

(1) Our interest in HIPS was relinquished in November 2006.

(2) 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.

2007 Acquisitions

During 2007, we completed four acquisitions for aggregate consideration of approximately $123 million. These acquisitions included (i) a commercial refined products supply and marketing business (reflected in our marketing segment) for approximately $8 million in cash, (ii) a trucking business (reflected in our transportation segment) for approximately $9 million in cash, (iii) the Bumstead LPG storage facility located near Phoenix, Arizona (reflected in our facilities segment) for approximately $52 million in cash and (iv) the Tirzah LPG storage facility and other assets located near York County, South Carolina (reflected in our facilities segment) for approximately $54 million in cash. The goodwill associated with these acquisitions was approximately $12 million.

Ongoing Acquisition Activities

Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase of assets and operations that are strategic and complementary to our existing operations. Such assets and operations include crude oil, refined products and LPG related assets and, through our interest in PAA/Vulcan, natural gas storage assets. In addition, we have in the past evaluated and pursued, 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. Even after we have reached agreement on a purchase price with a potential seller, confirmatory due diligence or negotiations regarding other terms of the acquisition can cause discussions to be terminated. Accordingly, we typically do not announce a transaction until after we have executed a definitive acquisition agreement. Although we expect the acquisitions we make to be accretive in the long term, we can provide no assurance that our expectations will ultimately be realized. See Item 1A. Risk Factors Risks Related to Our Business If we do not make acquisitions on economically acceptable terms, our future growth may be limited and Our acquisition strategy involves risks that may adversely affect our business.

Global Petroleum Market Overview

World oil consumption continues to increase and is forecast to increase approximately 35% by 2030. China, the Middle East, the United States and India are expected to account for most of the increase in oil consumption. The United States is the world s most liquid market for crude oil. The United States comprises less than 5% of the world s population and generates only 10% of the world s petroleum production, but consumes approximately 24% of the world s petroleum production. The following table sets forth projected world supply and demand for petroleum products (including crude oil, natural gas liquids and other liquid petroleum products) and is derived from the most recent information published by the Energy Information Administration (EIA) (see EIA website at www.eia.doe.gov).

			Projected	
	2007	**2008**	**2015**	**2030**
	(Millions of barrels per day)			
Supply				
U.S	8.6	8.6	10.3	10.4
Canada	3.4	3.6	4.3	5.3
Other	9.4	9.4	8.5	7.5
Organization for Economic Co-operation and Development (OECD)	21.4	21.6	23.1	23.2
Organization of the Petroleum Exporting Countries (OPEC)-12	34.8	36.2	35.9	45.0
Former Soviet Union	12.7	13.1	15.2	18.1
China	3.9	3.9	3.2	3.2
Other	11.8	12.3	20.2	27.8

Non-OECD	63.2	65.5	74.5	94.1
Total World Production	84.6	87.1	97.6	117.3

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			Projected	
	2007	**2008**	**2015**	**2030**
	(Millions of barrels per day)			
Demand				
U.S	20.7	21.0	22.8	26.8
Canada	2.3	2.2	2.5	2.6
Europe	15.4	15.4	15.9	16.3
Japan	5.2	5.2	5.5	5.5
Other	5.8	5.8	7.0	8.5
OECD	49.4	49.6	53.7	59.7
Other Asia	8.7	8.8	7.7	10.3
Former Soviet Union	4.4	4.5	6.0	7.1
China	7.7	8.2	10.0	15.1
Other	15.6	16.1	20.3	25.1
Non-OECD	36.4	37.6	44.0	57.6
Total World Consumption	85.8	87.2	97.7	117.3
Net World Production/(Consumption)	(1.2)	(0.1)	(0.1)	
U.S. Production as % of World Production	10%	10%	11%	9%
U.S. Consumption as % of World Consumption	24%	24%	23%	23%

World economic growth is a driver of the world petroleum market. To the extent that an event causes weaker world economic growth, energy demand would decline. Weaker energy demand would also result in lower energy consumption, lower energy prices, or both, depending on the production responses of producers. Recent volatility in the financial markets and other geopolitical factors have contributed to uncertainty in the petroleum market and, therefore, have caused significantly high volatility in prices and market structure.

Crude Oil Market Overview

The definition of a commodity is a mass-produced unspecialized product and implies the attribute of fungibility. Crude oil is typically referred to as a commodity, however it is neither unspecialized nor 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, which result in 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.

The lack of fungiblity of the various grades of crude oil creates logistical transportation, terminalling and storage challenges and inefficiencies associated with regional volumetric supply and demand imbalances. These logistical inefficiencies are created as certain qualities of crude oil are indigenous to particular regions or countries. Also, each refinery has a distinct configuration of process units designed to handle particular grades of crude oil. The relative yields and the cost to obtain, transport and process the crude oil drives the refinery s choice of feedstock. 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.

Our assets and our business strategy are designed to serve 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 EIA, during the twelve months ended October 2007, the United States consumed approximately 15.1 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 22 years, increasing from 3.2 million barrels per day in 1985 to 10.0 million barrels per day for the 12 months ended October 2007, as U.S. refinery demand has increased and domestic crude oil production has declined due to natural depletion. By 2030, foreign imports of crude oil in the U.S. are expected to increase to approximately 13.1 million barrels per day. The table below shows the overall domestic petroleum consumption projected out to 2030 and is derived from the most recent information published by the EIA (see EIA website at www.eia.doe.gov).

	Actual		Projected	
	2007	2008	2015	2030
	(Millions of barrels per day)			
Domestic Crude Oil Production	5.1	5.1	5.9	5.4
Net Imports Crude Oil	10.0	10.1	10.5	13.1
Crude Oil Input to Domestic Refineries	15.1	15.2	16.4	18.5
Net Product Imports	2.1	2.3	2.0	3.3
Other (NGL Production, Refinery Processing Gain)	3.5	3.5	4.4	5.0
Total Domestic Petroleum Consumption	20.7	21.0	22.8	26.8

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 2007 and is derived from information published by the EIA (see EIA website at www.eia.doe.gov) (in millions of barrels per day).

Petroleum Administration Defense District	Regional Supply	Refinery Demand	Supply Shortfall
PADD I (East Coast)		1.5	(1.5)
PADD II (Midwest)	0.5	3.2	(2.7)
PADD III (South)	2.8	7.4	(4.6)
PADD IV (Rockies)	0.4	0.5	(0.1)
PADD V (West Coast)	1.4	2.5	(1.1)
Total U.S.	5.1	15.1	(10.0)

Although PADD III has the largest absolute volume supply shortfall, we believe PADD II is 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 22 years, crude oil production in PADD II has declined from approximately 1.0 million barrels per day to approximately 470,000 barrels per day. Over this same time period, refinery demand has increased from approximately 2.7 million barrels per day in 1985 to 3.2 million barrels per day for the twelve months ended October 2007. As a result, the volume of crude oil transported into PADD II has increased approximately 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.

Volatility in the crude oil market has increased and we expect it to persist. Some factors that we believe are causing and will continue to cause volatility in the market include:

- The narrowing of the gap between supply and the worldwide growth in demand;
- A reduction in available tankage and U.S. inventory capacity caused by DOT regulations requiring regularly scheduled inspection and repair of tanks remaining in service;
- Regional supply and demand imbalances;
- Political instability in critical producing nations; and
- Significant fluctuations in absolute price as well as grade and location differentials.

The complexity and volatility of the crude oil market creates opportunities to solve the logistical inefficiencies inherent in the business. We believe we are well positioned to capture such opportunities through our:

- strategically located assets;
- specialized crude oil market knowledge;
- extensive relationships with producers and refiners;
- strong capital structure and liquidity position; and
- proven skill sets to acquire and integrate businesses and achieve synergies.

Refined Products Market Overview

Once crude oil is transported to a refinery, it is processed into different petroleum products. These refined products fall into three major categories: fuels such as motor gasoline and distillate fuel oil (diesel fuel and jet fuel); finished non-fuel products such as solvents, lubricating oils and asphalt; 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 and octane enhancers. The performance of the gasoline must meet strictly defined industry standards and environmental regulations that vary based on season and 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 and 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 2007, an increase of approximately 32%. By 2030, the EIA estimates that the U.S. will consume approximately 26.8 million barrels per day of refined products, an increase of approximately 30% over the last twelve months levels. We believe that the additional demand will be met by growth in the capacity of existing refineries through large expansion projects and capacity creep as well as increased imports of refined products, both of which we believe will generate incremental demand for midstream infrastructure, such as pipelines and terminals.

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

- multiple specifications of existing products (also referred to as boutique gasoline blends);
- specification changes to existing products, such as ultra low sulfur diesel;
- new products, such as bio-fuels;
- the aging of existing infrastructure; and

the potential reduction in storage capacity due to regulations governing the inspection, repair, alteration and construction of storage tanks.

The complexity and volatility of the refined products market creates opportunities to solve the logistical inefficiencies inherent in the business. We are well positioned in certain areas to capture such opportunities. 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 continuing to build a complementary refined products supply and marketing business.

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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 2007, an increase of approximately 30%. By 2030, the EIA estimates that the U.S. will consume approximately 2.4 million barrels per day of LPGs, an increase of approximately 14% over recent 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.

The LPG market is driven by seasonal shifts in regional demand including:

- weather;
- seasonal changes in gasoline specifications affecting demand for butane;
- alternating needs of refineries to store and blend LPG;
- complex transportation logistics;
- shortage of diluent for Canadian heavy oil; and
- inefficiency caused by multiple supply sources and numerous regional supply and demand imbalances.

The complexity and volatility of the LPG market creates opportunities to solve the logistical inefficiencies inherent in the business. We are well positioned in certain areas to capture such opportunities. We intend to grow our asset base in the LPG business through expansion projects and future acquisitions. We believe that our asset base provides flexibility in meeting the needs of our customers and opportunities to capitalize on regional supply and demand imbalances in LPG markets. In 2007, we acquired LPG storage facilities in Arizona and South Carolina with 133 million gallons and 52 million gallons of working capacity, respectively. These acquisitions increased our LPG storage capacity by over 33% and complement our activities in the Southeast and along the Eastern seaboard.

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. From 1990 to 2006, domestic natural gas production grew approximately 4% while domestic natural gas consumption rose approximately

13%, resulting in an approximate 133% 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.

A significant portion 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 2008, plans for 39 new LNG terminals in the United States and Bahamas have been proposed, 19 of which are to be situated along the Gulf Coast. Of the 19 proposed Gulf Coast facilities, 17 have been approved by the appropriate regulatory agencies, and 2 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.

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.

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 crude oil and refined products on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third party leases of pipeline capacity and transportation fees. Our transportation segment also includes our equity earnings from our investments in Butte and Frontier, in which we own minority interests, and Settoon Towing, in which we own a 50% interest.

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Following is a tabular presentation of our active pipeline assets in the United States and Canada as of December 31, 2007, grouped by geographic location:

Region / Pipeline and Gathering Systems(1)	System Miles	2007 Average Net Barrels per Day (in thousands)(2)
Southwest US		
Basin	519	378
Other	6,253	449
Southwest US Subtotal	**6,772**	**827**
Western US		
All American	139	47
Line 63/Line 2000	474	175
Other	74	84
Western US Subtotal	**687**	**306**
US Rocky Mountain		
Salt Lake City Core Area Systems	1,004	101
Other	3,296	256
US Rocky Mountain Subtotal	**4,300**	**357**
US Gulf Coast		
Capline(3)	633	235
Other	1,662	518
US Gulf Coast Subtotal	**2,295**	**753**
Central US Subtotal	**3,133**	**165**
Domestic Total	**17,187**	**2,408**
Canada		
Rangeland	1,015	63
Manito	610	73
Other	740	168
Canada Total	**2,365**	**304**
Grand Total	**19,552**	**2,712**
Pipeline and Gathering Systems Under Construction		
Salt Lake City Expansion	95	N/A

(1) Ownership percentage varies on each pipeline and gathering system ranging from approximately 20% to 100%.

(2) Represents average volumes for the entire year of 2007.

(3) Non-operated pipeline.

Southwest US

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 crude oil from the Permian Basin (in west Texas and southern New Mexico) 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 378,000 barrels per day (net to our interest) during 2007.

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 6 million barrels (5 million barrels, net to our interest) of crude oil storage capacity located along the system. The Basin system is subject to tariff rates regulated by the FERC.

Western US

All American Pipeline System. We own a 100% interest in the 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 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 2007 and 2006, tariffs on the All American Pipeline averaged $2.18 per barrel and $2.07 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 63 and Line 2000, 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. Volumes shipped from the OCS are in decline (as reflected in the table below). See Item 1A. Risk Factors for discussion of the estimated impact of a decline in volumes.

The table below sets forth the historical volumes received from both of these fields for the past five years (barrels in thousands):

	For the Year Ended December 31,				
	2007	**2006**	**2005**	**2004**	**2003**
Average daily volumes received from:					
Point Arguello (at Gaviota)	8	9	10	10	13
Santa Ynez (at Las Flores)	38	40	41	44	46
Total	46	49	51	54	59

Line 63. We own a 100% interest in the Line 63 system. 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 OCS to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. The Line 63 system consists of a 107-mile trunk pipeline (of which 93 miles is 14-inch pipe and 14 miles is 16-inch pipe), originating at our Kelley Pump Station in Kern County, California and terminating at our West Hynes Station in Long Beach, California. The trunk pipeline has a capacity of approximately 110,000 barrels per day. The Line 63 system includes 60 miles of distribution pipelines in the Los Angeles Basin, with a capacity of approximately 144,000 barrels per day, and in the Bakersfield area, 156 miles of gathering pipelines in the San Joaquin Valley, and 22 storage tanks with approximately 1 million barrels of storage capacity and approximately 72,000 barrels per day of throughput capacity. These storage assets are used primarily to facilitate the transportation of crude oil on the Line 63 system. For 2007, combined throughput on all three Line 63 segments totaled an average of approximately 109,000 barrels per day.

Line 2000. We own and operate 100% of Line 2000, an intrastate common carrier crude oil pipeline that originates at our Emidio Pump Station (that is part of the All American Pipeline System) and transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin. Line 2000 is a 151-mile, 20-inch trunk pipeline with a throughput capacity of 130,000 barrels per day. During 2007, throughput on Line 2000 averaged approximately 66,000 barrels per day.

US Rocky Mountain

Salt Lake City Core Area Systems. We own and operate the Salt Lake City Core area systems, which include 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 Area systems consist 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 million barrels of storage capacity as well as 44 miles of extension pipeline (the AREPI System). The trunk pipeline 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. During 2007, throughput on the Salt Lake City Core Area systems averaged approximately 101,000 barrels per day.

US Gulf Coast

Capline Pipeline System. 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 approximately 3 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 approximately 1 million barrels per day of crude oil, approximately 248,000 barrels per day are subject to our interest. During 2007, throughput on our interest averaged approximately 235,000 barrels per day.

Canada

Rangeland System. We own a 100% interest in the Rangeland system. The Rangeland system includes the Mid Alberta Pipeline and the Rangeland Pipeline. The Mid Alberta Pipeline is a 141-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. We plan to convert the Mid Alberta Pipeline into a bi-directional pipeline. The Rangeland Pipeline is a proprietary pipeline system that consists of approximately 875 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 80,000 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 56-mile pipeline for high sulfur crude oil, and a 63-mile pipeline for condensate and butane. From Rimbey, third-party pipelines move product north to Edmonton. For 2007, approximately 29,000 barrels per day of crude oil was transported on the segment of the pipeline from Sundre north to Edmonton and approximately 34,000 barrels per day was transported on the pipeline from Sundre south to the United States.

Manito. We own a 100% interest in the Manito heavy oil system. This 610-mile system is comprised of the Manito pipeline, the North Sask pipeline and the Bodo/Cactus Lake pipeline. The North Sask pipeline is 84 miles in length and originates near Turtleford, Saskatchewan and terminates in Dulwich, Saskatchewan. Dulwich is the initiation point of the Manito pipeline which is 381 miles long and terminates in Kerrobert, Saskatchewan at our storage and terminalling facility. The Bodo/Cactus Lake pipeline is 145 miles long and originates in Bodo, Alberta and also terminates at our Kerrobert storage facility. The Kerrobert storage and terminalling facility is connected to the Enbridge pipeline system. For 2007, approximately 73,000 barrels per day of crude oil was transported in the Manito system.

Pipeline and Gathering Systems Under Construction

Salt Lake City Expansion. We are constructing a 95-mile expansion of the Salt Lake City Core system from Wasatch to Salt Lake City, which is scheduled to be completed in the second quarter of 2008. When completed, the volumes from the AREPI System will be transported on the Salt Lake City Expansion and the AREPI System will be shut down. The Salt Lake City Expansion pipeline will have an estimated capacity of 120,000 barrels per day. We have entered into 10-year transportation contracts with four Salt Lake City refiners for service on this pipeline. Also, in November 2007, we signed a master formation agreement through which we will sell a 25% interest in this line to Holly Energy Partners, L.P. As part of this agreement, Holly Refining and Marketing Company 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 $83 million.

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. 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, (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 and (iii) fees from LPG fractionation and isomerization services. Our facilities segment also includes our equity earnings from our investment in PAA/Vulcan.

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Following is a tabular presentation of our active facilities segment assets and those under construction in the United States and Canada as of December 31, 2007, grouped by product type:

Facility	Capacity (in millions of barrels, except where noted)
Crude Oil and Refined Products	
In service:	
Cushing	9
Philadelphia Area	3
Kerrobert	2
LA Basin	10
Martinez and Richmond	5
Mobile and Ten Mile	5
St. James	4
Other	9
Subtotal	**47**
Under construction:	
Cushing	2
Patoka	3
Philadelphia Area	1
St. James	2
Other	2
Pier 400	Under Development
Subtotal	**10**
LPG	
In service:	
Bumstead	2
Tirzah	1
Other	3
Subtotal	**6**
Under construction:	
Bumstead	1
Natural Gas	
In service:	
Bluewater/Kimball(1)	26 Bcf (2)(3)
Under construction:	
Pine Prairie(1)	24 Bcf (2)(3)

(1) Owned through our interest in PAA/Vulcan joint venture.

(2) Our interest in these facilities is 50% of the capacity.

(3) Billion cubic feet (Bcf)

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

Major Facilities Assets

Crude Oil and Refined Products

Cushing Terminal. Our Cushing, Oklahoma Terminal (the 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 enabling deliveries to connecting carriers at their maximum rate. The facility also incorporates numerous environmental and operation safeguards that distinguish it from all other facilities at the Cushing Interchange.

Since 1999, we have completed six separate expansion phases, which increased the capacity of the Cushing Terminal to a total of approximately 11 million barrels. The Cushing Terminal now consists of fourteen 100,000-barrel tanks, four 150,000-barrel tanks, twenty 270,000-barrel tanks and six 570,000-barrel tanks, all of which are used to store and terminal crude oil. The six 570,000-barrel tanks were placed into service in the fourth quarter of 2007 and the first quarter of 2008, at a cost of approximately $49 million. The expansion is supported by multi-year lease agreements. Our tankage ranges in age from one year to approximately 14 years with an average age of five years. In contrast, we estimate that the average age of the remaining tanks in Cushing owned by third parties is approximately 30 years.

Philadelphia Area Terminals. We own three refined product terminals in the Philadelphia, Pennsylvania area. Our Philadelphia area terminals have 40 storage tanks with combined storage capacity of approximately 3 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, and include two dock facilities that can load approximately 10,000 to 12,000 barrels per hour of refined products and black oils (heavy crude oils). The Philadelphia area terminals also receive products from connecting pipelines and offer truck loading services.

At our Philadelphia area terminals, we have completed an ethanol expansion project that enabled us to increase our ethanol handling and blending capabilities as well as our marine receipt capabilities. We plan to expand the facilities by approximately 1 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 the third quarter of 2009 at an estimated cost of $44 million, of which approximately $30 million is scheduled to be spent in 2008.

Kerrobert Terminal. We own a crude oil and condensate storage and terminalling facility, which is located near Kerrobert, Saskatchewan and is connected to our Manito and Cactus Lake pipeline systems. In 2006, we increased the storage capacity at our Kerrobert facility by 600,000 barrels of tankage and an additional 300,000 barrels of tankage was added in 2007, bringing the total storage capacity to approximately 2 million barrels. The cost of these expansions aggregated approximately $42 million. In 2008, we will commence an additional internal growth project on the Kerrobert terminal, which will increase receipt and delivery capacity and reduce third-party costs. The cost of the project is estimated to be approximately $40 million, of which approximately $36 million is estimated to be incurred in 2008.

LA Basin. We own four crude oil and refined product storage facilities in the Los Angeles area with a total of 10 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 35 storage tanks. Approximately 8 million barrels of the storage capacity are in active commercial service, 1 million barrels are used primarily for throughput to other storage tanks and for displacement oil and do not generate revenue independently and the remaining approximately 1 million barrels are out of service. We expect to complete refurbishing the out of service barrels in 2008. We also plan to add approximately 1 million barrels of additional tankage in 2008 at an estimated cost of approximately $20 million, of which approximately $13 million is scheduled to be spent in 2008. 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. 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 terminal at Martinez (which provides refined product and crude oil service) and a terminal at Richmond (which provides refined product service). Our San Francisco area terminals currently have 56 storage tanks with approximately 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.

In 2007, we completed an additional 850,000 barrels of storage capacity at an estimated project cost of approximately $29 million.

Mobile and Ten Mile Terminal. We have a marine terminal in Mobile, Alabama (the Mobile Terminal) that consists of seventeen tanks ranging in size from 10,000 barrels to 225,000 barrels, with current useable capacity of approximately 2 million barrels. Approximately 3 million barrels of additional storage capacity is available at our nearby Ten Mile Facility through a 36-inch pipeline connecting the two facilities.

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 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. Phase I consists of approximately 4 million barrels of capacity and includes seven tanks ranging from 210,000 barrels to 670,000 barrels. The facility also includes a manifold and header system that allows for receipts and deliveries with connecting pipelines at their maximum operating capacity. Phase I was completed and placed in service in 2007.

Under the Phase II project, we will construct approximately 2 million barrels of additional tankage at the facility. The Phase II project will expand the total capacity of the facility to approximately 6 million barrels at an estimated project cost of approximately $64 million, of which approximately $8 million is estimated to be incurred in 2008. We estimate that Phase II will be completed in phases in 2008 and 2009.

New Crude Oil Storage Facilities Under Construction and Under Development

Patoka Terminal. In December 2006, we announced plans to build a 3 million barrel crude oil storage and terminal facility at the Patoka Interchange in southern 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 incurred approximately $30 million in 2007 and expect to incur approximately $43 million of the estimated total project cost in 2008. We expect Patoka to be 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 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 refiners in the Los Angeles Basin that provide long-term customer commitments to off-load a total of 200,000 barrels per day of crude oil at the Pier 400 dock. The 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.

Due primarily to regulatory processes and delays, we have failed to meet certain project milestone dates set forth in one of our agreements, and we are likely to miss other project milestones that are approaching under this agreement. However, the counterparty has not given any indication that it will seek to terminate such agreements. We expect that ongoing negotiations with the counterparty to extend the milestone dates will be successful and that the agreements will remain in effect.

In February 2008, we completed an updated cost estimate for the project. We are estimating that Pier 400, when completed, will cost approximately $468 million, which amount includes $32 million of costs associated with emission reduction credits and development and engineering costs incurred to date and $28 million of estimated capitalized interest to be incurred during the construction period. This estimate is subject to change depending on various factors, including the final scope of the project and the requirements imposed through the permitting process. This cost estimate assumes the construction of 4 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. 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 (including the Environmental Impact Review), and ongoing feasibility evaluation. Subject to timely receipt of approvals, we expect construction of the Pier 400 terminal may be partially completed and the facility placed in service in 2010 and to be fully operational in 2011.

LPG Storage Facilities and Terminals

Bumstead. In July 2007, we acquired the Bumstead LPG storage facility for $52 million from AmeriGas Propane. The Bumstead facility is located at a major rail transit point near Phoenix, Arizona. With 133 million gallons of working capacity (approximately 100 million gallons, or approximately 2 million barrels, of useable capacity), the facility s primary assets include three salt-dome storage caverns, a 24-car rail rack and six truck racks.

In 2008, we will commence an internal growth project on the Bumstead facility, intended to increase capacity by approximately 1 million barrels, add rail car storage capacity and improve the efficiency of the rail rack. The cost of the project is estimated to be approximately $14 million, of which approximately $10 million is estimated to be incurred in 2008.

Tirzah. In October 2007, we acquired the Tirzah LPG storage facility for approximately $54 million from Suburban Propane. The facility has an approximately 1 million barrel underground granite storage cavern and is connected to the Dixie Pipeline System (a third-party system). The facility gives us a greater presence in the Southeast.

We believe these facilities will further support the expansion of our LPG business in North America 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 North America.

Natural Gas Storage Assets (owned through our interest in PAA/Vulcan)

Bluewater/Kimball. The Bluewater gas storage facility, which is located near Detroit, Michigan, is a depleted reservoir with approximately 23 Bcf of capacity and is also strategically positioned. In April 2006, PAA/Vulcan acquired the Kimball gas storage facility and connected this 3 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 2008 and fully operational in 2010, 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, Louisiana LNG terminal, which is the largest LNG import facility in the United States. The initial phase of the facility will consist of three storage caverns with a targeted working capacity of 8 Bcf per cavern and an extensive header system. Drilling operations on all three cavern wells are complete. 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. In January 2008, we applied for a permit to convert the first cavern well from a brine extraction well to a natural gas storage well. The site is located approximately 50 miles from the Henry Hub in Louisiana (the delivery point for NYMEX natural gas futures contracts). Pine Prairie 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 needs 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 and the seasonal storage of LPG;

- 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

- 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.

We believe our marketing activities are counter-cyclically balanced to produce a stable baseline of results in a variety of market conditions, while at the same time providing upside potential associated with opportunities inherent in volatile market conditions. These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies to provide a 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.

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 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, refined products, LPG sales and waterborne foreign crude imported for the year ended December 31, 2007 (in thousands of barrels):

	Volumes
Crude oil lease gathering	685
Refined products	11
LPG sales	90
Waterborne foreign crude imported	71
Marketing activities total	857

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 trucks 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. Crude oil and LPG is purchased 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, 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 for further discussion of our accounting for exchange and buy/sell agreements.

Credit. Our merchant activities involve the purchase of crude oil, LPG and refined products for resale and require significant extensions of credit by our suppliers. In order to assure our ability to perform our obligations under the 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, LPG and refined products, 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.

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 the date we issue an invoice for the provision of services.

We also have credit risk exposure related to our sales of LPG and refined products; however, because our sales are typically in relatively small amounts to individual customers, we do not believe that these transactions pose a material concentration of credit risk. Typically, we enter into annual contracts to sell LPG on a forward basis, as well as to sell LPG on a current basis to local distributors and retailers. In certain cases our LPG customers prepay for their purchases, in amounts ranging from approximately $2 per barrel to 100% of their contracted amounts. Generally, sales of LPG settle within 30 days of the date of invoice and refined products sales settle within 10 days.

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 $100 per barrel (February 2008) to a low of approximately $10 per barrel (March 1986) over the last 22 years. Segment profit from our transportation activities is dependent on throughput volume, tariff rates and the level of other fees generated on our pipeline systems. 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 forward 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 delivery prices in the futures markets.

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 effect 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.

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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 by producers, refiners, utilities and trading entities has increased, 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 outright 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.

Geographic Data; Financial Information about Segments

See Note 15 to our Consolidated Financial Statements.

Customers

Marathon Petroleum Company, LLC (Marathon) accounted for approximately 19%, 14% and 11% of our total revenues for each of the three years ended December 31, 2007, 2006 and 2005, respectively. Valero Marketing & Supply Company (Valero) accounted for 10% of our revenues for the year ended December 31, 2007. ConocoPhillips Company (Conoco) accounted for 11% of our revenues for the year ended December 31, 2007. BP Oil Supply accounted for 14% of our revenues for the year ended December 31, 2005. No other customers accounted for 10% or more of our revenues during any of the last three years. The majority of revenues from these customers 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 are exposed to significant competition based on the relatively low 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, investment banks that have established a trading platform, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources many times greater than ours, and control greater supplies of crude oil.

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

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 rules and regulations binding on the 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. We are cooperating in a Department of Justice/Environmental Protection Agency proceeding regarding certain releases of crude oil. The proceeding could result in injunctive remedies the effect of which would subject us to operational requirements and constraints that would not apply to our competitors. See Item 3. Legal Proceedings.

Following is a discussion of certain laws and regulations affecting us. However, you should not rely on such discussion as an exhaustive review of all regulatory considerations affecting our operations.

Pipeline Safety

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. In addition, federal regulations require pipeline operators to implement measures designed to reduce the environmental impact of oil discharges from onshore oil pipelines. These regulations require operators to maintain comprehensive spill response plans, including extensive spill response training for pipeline personnel. 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.

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In 2001, the DOT adopted the initial pipeline integrity management rules, which require 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. Segments of our pipelines that transport hazardous liquids 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 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 the inspection, testing and correction of identified anomalies were approximately $15 million in 2007, $8 million in 2006 and $5 million in 2005. Based on currently available information, our preliminary estimate for 2008 is that we will incur approximately $12 million in operational expenditures and approximately $18 million in capital expenditures associated with our pipeline integrity management program. 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 (most of the operational expenditures and a much smaller portion of the capital expenditures) 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 rural onshore hazardous liquids gathering and low-stress pipeline systems found near unusually sensitive areas, including non-populated areas requiring extra protection because of the presence of sole source drinking water resources, endangered species, or other ecological resources. In December 2006, H.R. 5782, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (the 2006 Pipeline Safety Act), which reauthorizes and amends the DOT s pipeline safety programs, became law. Included in the 2006 Pipeline Safety Act is a provision eliminating the regulatory exemption for hazardous liquid pipelines operated at low stress. While new regulations have not yet been adopted in response to the NPRM and the 2006 Pipeline Safety Act, DOT has indicated that it expects to adopt appropriate new rules for low stress pipelines during 2008. Although any new regulation of hazardous liquid low stress pipelines and any future regulation of hazardous liquid gathering lines could include requirements for the establishment of additional pipeline integrity management programs, we do not expect pending regulations to have a material impact on our operating expenses.

The acquisitions we have completed over the last several years have included pipeline assets of varying ages and maintenance and operational histories. Accordingly, for 2008 and beyond we will continue to focus on pipeline integrity management as a primary operational emphasis. In that regard, we have added staff and implemented programs intended to improve the integrity of our assets, with a focus on risk reduction through testing, enhanced corrosion control, leak detection, and damage prevention. We have expanded an internal review process in which we are reviewing various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management mandate. The purpose of this process is to evaluate the surrounding environment, as well as the condition and operating history of these pipelines and gathering assets, to determine if such assets warrant additional investment or replacement. Accordingly, in addition to potential cost increases related to unanticipated regulatory changes or injunctive remedies resulting from Environmental Protection Agency (EPA) enforcement actions, 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 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. See Item 3. Legal Proceedings Environmental.

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.

The DOT has adopted American Petroleum Institute Standard 653 (API 653) as the standard for the inspection, repair, alteration and reconstruction of existing crude oil storage tanks 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 $18 million, $7 million and $4 million in 2007, 2006 and 2005, respectively. Based on currently available information, we anticipate we will spend an approximate average of $24 million per year for 2008 and 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 Resources Conservation Board (ERCB) and Saskatchewan Ministry of Energy 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 $6 million in 2007, $5 million in 2006 and $5 million in 2005 on compliance activities. Our preliminary estimate for 2008 is approximately $7 million. Certain of these costs are recurring in nature and thus will affect 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

Our pipeline assets and transportation activities are subject to several transportation regulations. Our historical and projected operating costs reflect the recurring costs resulting from compliance with these regulations, and we do not anticipate material expenditures in excess of these amounts in the absence of future acquisitions or changes in regulation, or discovery of existing but unknown compliance issues. The following is a summary of the transportation regulations that may impact our operations.

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 ERCB. 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.

Regulation of OCS Pipelines. The Outer Continental Shelf Lands Act (OCSLA) requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. In April 2007, the Minerals Management Service (MMS) issued a notice of proposed rulemaking that would establish a process for a shipper transporting oil or gas production from OCS leases to follow if it believes it has been denied open and nondiscriminatory access to OCS pipelines. We have no way of knowing what rules the MMS will ultimately adopt regarding access to OCS transportation, however, such rules are not expected to have a material impact on our operations or results.

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, which 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%. 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) to 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 FERC s current income tax allowance 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 tax allowance policy was upheld by the D.C. Circuit on May 29, 2007. FERC continues to refine its tax allowance policy in case-by-case reviews; how the Policy Statement is applied in practice to pipelines owned by MLPs could affect the rates of pipelines regulated by FERC.

The D.C. Circuit s May 29, 2007 decision also held that the FERC s determination that a rate is no longer subject to grandfathering protection under the EP Act 1992 when there has been a substantial change in the overall rate of return of the pipeline, rather than in one cost element. Further, the D.C. Circuit declined to consider arguments that there were errors in the FERC s method for determining substantial change, finding that the parties had not first raised such allegations with FERC. On August 20, 2007, the D.C. Circuit denied a petition for rehearing of the May 29 decision with respect to the alleged errors in the FERC s method for determining substantial change and the decision is now final.

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 transportation segment profit 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, facility inspection, reporting and safety.

Cross Border Regulation

As a result of our Canadian acquisitions and cross border activities, including importation of crude oil between the United States and Canada, 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. In addition, FERC s authority extends to maintenance of accounts and records, terms and conditions of service, depreciation and amortization policies, acquisition and disposition of facilities, initiation and discontinuation of services and relationships between pipelines and storage companies and certain affiliates.

Absent an exemption granted by the FERC, FERC s Standards 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 U.S. storage facility operators to their affiliated gas marketing entities. 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 storage companies, 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.

Under the Energy Policy Act of 2005 (EP Act 2005) and related regulations, it is 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, which implements the antimanipulation provision of EP Act 2005. Pursuant to EP Act 2005 and Order No. 670, it is unlawful in connection with the purchase or sale of natural gas or transportation services subject to the jurisdiction of FERC 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 EP Act 2005 also gives 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. 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, the FERC, state commissions and the courts.

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 could 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 subject us to additional operational requirements and constraints. Environmental and safety 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.

The following is a summary of some of the environmental and safety laws and regulations to which our operations are subject.

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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 $350 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 federal, 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 Regulations Pipeline Safety and Note 11 to our Consolidated Financial Statements. Permits or approvals must be obtained to discharge pollutants into these waters. A permit is also required for the discharge of dredge and fill material into regulated waters, including wetlands. Federal, state and provincial regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. 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.

Air Emissions

Our operations are subject to the U.S. Clean Air Act (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. In addition, states can impose air emissions limitations that are more stringent than the federal standards imposed by EPA. Federal, state and provincial regulatory agencies can also impose administrative, civil and/or criminal penalties for non-compliance with air permits or other requirements of the Clean Air Act and associated state laws and regulations. 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.

In response to the Kyoto Protocol, the Canadian federal government introduced the *Regulatory Framework for Air Emissions* (the Regulatory Framework) for regulating air pollution and industrial greenhouse gas emissions (GHG) by establishing mandatory emissions reduction requirements on a sector basis. Sector-specific regulations are expected to come into force in 2010 and targets would be based on percentages rather than absolute reductions. The Regulatory Framework also proposes a credit emissions trading system. Additionally, regulation can take place

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at the provincial and municipal level. For example, Alberta introduced the *Climate Change and Emissions Management Act,* which provides a framework for managing GHG by reducing specified gas emissions relative to gross domestic product to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020 and which imposes duties to report. The accompanying regulation, the *Specified Gas Emitters Regulation,* effective July 1, 2007, requires mandatory emissions reductions through the use of emissions intensity targets. The Canadian federal government proposes to enter into equivalency agreements with provinces that establish a regulatory regime to ensure consistency with the federal plan, but the success of any such proposal remains in doubt.

Although the United States is not participating in the Kyoto Protocol, the current session of Congress is considering climate-change related legislation to restrict greenhouse gas emissions. One bill recently approved by the U.S. Senate Environment and Public Works Committee, known as the Lieberman-Warner Climate Security Act, would require a 70% reduction in emissions of greenhouse gases (from sources within the United States) between 2012 and 2050. In addition, at least 17 states have declined to wait on Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. 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. Also, as a result of the U.S. Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court s holding in Massachusetts that greenhouse gases fall under the Clean Air Act s definition of air pollutant may also result in future regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New 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 could adversely affect our operations and demand for our services.

Solid Waste

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

Hazardous Substances

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

Occupational Safety and Health

We are subject to the requirements of OSHA and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that certain information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with OSHA requirements, including general industry standards, recordkeeping requirements and monitoring of occupational exposure to regulated substances.

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

Endangered Species Act

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

Environmental Remediation

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

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

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

For instance, in connection with the purchase of assets from Link in 2004, we identified a number of environmental liabilities for which we received a purchase price reduction from Link and recorded a total environmental reserve of $20 million. A substantial portion of these environmental liabilities are associated with the former Texas New Mexico (TNM) pipeline assets. On the effective date of the acquisition, we and TNM entered into a cost-sharing agreement whereby, on a tiered basis, we agreed to bear $11 million of the first

$20 million of pre-May 1999 environmental issues. We also agreed to bear the first $25,000 per site for sites requiring remediation that were not identified at the time we entered into the agreement (capped at 100 sites). TNM agreed to pay all costs in excess of $20 million (excluding the deductible for new sites). TNM s obligations are guaranteed by Shell Oil Products (SOP). As of December 31, 2007, we had incurred approximately $11 million of remediation costs associated with these sites; SOP s share is approximately $3 million.

In connection with the acquisition of certain crude oil transmission and gathering assets from SOP in 2002, SOP purchased an environmental insurance policy covering known and unknown environmental matters associated with operations prior to closing. We are a named beneficiary under the policy, which has a $100,000 deductible per site, an aggregate coverage limit of $70 million, and expires in 2012.

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

As a result of our merger with Pacific, we have assumed liability for a number of ongoing remediation sites, associated with releases from pipeline or storage operations. These sites had been managed by Pacific prior to the merger, and in general there is no insurance or indemnification to cover ongoing costs to address these sites (with the exception of the Pyramid Lake crude oil release, which is discussed in Item 3. Legal Proceedings). We have evaluated each of the sites requiring remediation, through review of technical and regulatory documents, discussions with Pacific, and our experience at investigating and remediating releases from pipeline and storage operations. We have developed reserve estimates for the Pacific sites based on this evaluation, including determination of current and long-term reserve amounts, which total approximately $21 million. The remediation obligation for certain sites such as at the products terminal at Paulsboro, New Jersey, is being contested. See Item 3. Legal Proceedings.

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

Operational Hazards and Insurance

Pipelines, terminals, trucks or other facilities or equipment may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. Since we and our predecessors commenced midstream crude oil activities in the early 1990s, we have maintained insurance of various types and varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. However, such insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. Consistent with insurance coverage generally available to the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences. Over the last several years, our operations have expanded significantly, with total assets increasing over 1,500% since the end of 1998. At the same time that the scale and scope of our business activities have expanded, the breadth and depth of the available insurance markets have contracted. The overall cost of such insurance as well as the deductibles and overall retention levels that we maintain have increased. Some of this may be attributable to the events of September 11, 2001, which adversely impacted the availability and costs of certain types of coverage. Certain aspects of these conditions were further exacerbated by the hurricanes along the Gulf Coast during 2005, which also had an adverse effect on the availability and cost of coverage. As a result, we have elected to self-insure more activities against certain of these operating hazards and expect this trend will continue in the future. Due to the events of September 11, 2001, insurers have excluded acts of terrorism and sabotage from our insurance policies. We have elected to purchase a separate insurance policy for acts of terrorism and sabotage.

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

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

Title to Properties and Rights-of-Way

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

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of such property and, in some instances, such rights-of-way are revocable at the election of the grantor. In many instances, lands over which rights-of-way have been obtained are subject to prior liens that have not been subordinated to the right-of-way grants. In some cases, not all of the apparent record owners have joined in the right-of-way grants, but in substantially all such cases, signatures of the owners of majority interests have been obtained. We have obtained permits from public authorities to cross over or under, or to lay facilities in or along water courses, county roads, municipal streets and state highways, and in some instances, such permits are revocable at the election of the grantor. We have also obtained permits from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor s election. In some cases, property for pipeline purposes was purchased in fee. All of the pump stations are located on property owned in fee or property under leases. In certain states and under certain circumstances, we have the right of eminent domain to acquire rights-of-way and lands necessary for our common carrier pipelines.

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

Employees and Labor Relations

To carry out our operations, our general partner or its affiliates (including PMC (Nova Scotia) Company) employed approximately 3,100 employees at December 31, 2007. None of the employees of our general partner were subject to a collective bargaining agreement, except for eight employees with whom we have a collective bargaining agreement that will end on September 30, 2009. Our general partner considers its employee relations to be good.

Summary of Tax Considerations

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

Partnership Status; Cash Distributions

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

Partnership Allocations

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

Basis of Common Units

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

Limitations on Deductibility of Partnership Losses

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

Section 754 Election

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

Disposition of Common Units

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

Foreign, State, Local and Other Tax Considerations

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

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

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

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

Available Information

We make available, free of charge on our Internet website (http://www.paalp.com), our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file the material with, or furnish it to, the Securities and Exchange Commission.

Item 1A. *Risk Factors*

Risks Related to Our Business

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

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

In addition, our trading operations involve the risk of non-compliance with our trading policies. For example, we discovered in November 1999 that our trading policy was violated by one of our former employees, which resulted in aggregate losses of approximately $181 million. We have taken steps within our organization to enhance our processes and procedures to detect future unauthorized trading. We cannot assure you, however, that these steps will detect and prevent all violations of our trading policies and procedures, particularly if deception or other intentional misconduct is involved.

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

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

Today we own approximately three times the miles of pipeline we owned four years ago. We have also increased our terminalling and storage capacity and operate several facilities on or near navigable waters and domestic water supplies. As we have expanded our asset base, we have observed an increase in the number of releases of liquid hydrocarbons into the environment. These releases expose us to potentially substantial expense, including clean-up and remediation costs, fines and penalties, and third party claims for personal injury or property damage related to past or future releases. Some of these expenses could increase by amounts disproportionately higher than the relative increase in pipeline mileage and the increase in revenues associated therewith. During 2006 and 2007, we acquired refined products pipeline and terminalling assets. These assets are also subject to significant compliance costs and liabilities. In addition, because of their increased volatility and tendency to migrate farther and faster than crude oil, releases of refined products into the environment can have a more significant impact than crude oil and require significantly higher expenditures to respond and remediate. The incurrence of such expenses not covered by insurance, indemnity or reserves could materially adversely affect our results of operations.

We currently devote substantial resources to comply with DOT-mandated pipeline integrity rules. The 2006 Pipeline Safety Act, enacted in December 2006, requires the DOT to issue regulations for certain pipelines that were not previously subject to regulation. While new regulations have not yet been adopted, DOT has indicated that it expects to adopt appropriate new rules during 2008. These regulations will include requirements for the establishment of additional pipeline integrity management programs.

The acquisitions we have completed over the last several years have included pipeline assets of varying ages and maintenance and operational histories. Accordingly, for 2008 and beyond we will continue to focus on pipeline integrity management as a primary operational emphasis. In that regard, we have added staff and implemented programs intended to improve the integrity of our assets, with a focus on risk reduction through testing, enhanced corrosion control, leak detection, and damage prevention. We have expanded an internal review process pursuant to which we review various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management mandate. The purpose of this process is to review the surrounding environment, condition and operating history of these pipeline and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, in addition to potential cost increases related to unanticipated regulatory changes or injunctive remedies resulting from EPA enforcement actions, 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. See Item 3. Legal Proceedings Environmental.

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

We believe that, because of our strategic asset base and complementary business model, we will continue to benefit from swings in market prices and shifts in market structure during periods of volatility in the crude oil market. Our ability to capture that benefit, however, is subject to numerous risks and uncertainties, including our maintaining an attractive credit rating and continuing to receive open credit from our suppliers and trade counterparties. For example, our ability to utilize our crude oil storage capacity for merchant activities to capture contango market opportunities is dependent upon having adequate credit facilities, including the total amount of credit facilities and the cost of such credit facilities, which enables us to finance the storage of the crude oil from the time we complete the purchase of the oil until the time we complete the sale of the oil

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

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

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

A significant portion of our transportation segment profit is derived from pipeline transportation tariff associated with the Santa Ynez and Point Arguello fields located offshore California and the onshore fields in the San Joaquin Valley. We expect that there will continue to be natural production declines from each of these fields as the underlying reservoirs are depleted. In addition, any significant production disruption from OCS fields and the San Joaquin Valley due to production problems, transportation problems or other reasons could have a material adverse effect on our business. We estimate that a 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual transportation segment profit of approximately $7 million. A similar decline in volumes shipped from the San Joaquin Valley would result in an estimated $3 million decrease in annual transportation segment profit.

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

Third party shippers generally do not have long-term contractual commitments to ship crude oil on our pipelines. A decision by a shipper to substantially reduce or cease to ship volumes of crude oil on our pipelines could cause a significant decline in our revenues.

To maintain the volumes of crude oil we purchase in connection with our operations, we must continue to contract for new supplies of crude oil to offset volumes lost because of natural declines in crude oil production from depleting wells or volumes lost to competitors. Replacement of lost volumes of crude oil is particularly difficult in an environment where production is low and competition to gather available production is intense. Generally, because producers experience inconveniences in switching crude oil purchasers, such as delays in receipt of proceeds while awaiting the preparation of new division orders, producers typically do not change purchasers on the basis of minor variations in price. Thus, we may experience difficulty acquiring crude oil at the wellhead in areas where relationships already exist between producers and other gatherers and purchasers of crude oil.

Fluctuations in demand can negatively affect our operating results.

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

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

Our results of operations are influenced by the overall forward market for crude oil, and certain market structures or the absence of pricing volatility may adversely impact our results.

Results from our marketing segment are influenced by the overall forward market for crude oil. A contango market (meaning that the price of crude oil for future deliveries is higher than current prices) is favorable to commercial strategies that are associated with storage tankage as it allows a party to simultaneously purchase production at current prices for storage and sell at higher prices for future delivery. A backwardated market (meaning that the price of crude oil for future deliveries is lower than current prices) has a positive impact on lease gathering margins because crude oil gatherers can capture a premium for prompt deliveries; however, in this environment there is little incentive to store crude oil as current prices are above future delivery prices. In either case, margins can be improved when prices are volatile. The periods between these two market structures 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 effect 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 least beneficial environment for our marketing segment.

The wide contango spreads experienced over the last couple of years, combined with the level of price structure volatility during that time period, has had a favorable impact on our results. If the market remains in the slightly backwardated to transitional structure that has generally prevailed since July 2007, our future results from our marketing segment may be less than those generated during the more favorable contango market conditions that prevailed throughout most of 2005 and 2006 and the first half of 2007. Moreover, a prolonged transition period or a lack of volatility in the pricing structure may further negatively impact our results.

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

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

In evaluating acquisitions, we generally prepare one or more financial cases based on a number of business, industry, economic, legal, regulatory, and other assumptions applicable to the proposed transaction. Although we expect a reasonable basis will exist for those assumptions, the assumptions will generally involve current estimates of future conditions, which are difficult to predict. Realization of many of the assumptions will be beyond our control. Moreover, the uncertainty and risk of inaccuracy associated with any financial projection will increase with the length of the forecasted period. Some acquisitions may not be accretive in the near term, and will be accretive in the long term only if we are able timely and effectively to integrate the underlying assets and such assets perform at or near the levels anticipated in our acquisition projections.

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

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

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

Any acquisition involves potential risks, including:

- performance from the acquired assets and businesses that is below the forecasts we used in evaluating the acquisition;

a significant increase in our indebtedness and working capital requirements;

the inability to timely and effectively integrate the operations of recently acquired businesses or assets;

the incurrence of substantial unforeseen environmental and other liabilities arising out of the acquired businesses or assets, including liabilities arising from the operation of the acquired businesses or assets prior to our acquisition;

risks associated with operating in lines of business that are distinct and separate from our historical operations;

customer or key employee loss from the acquired businesses; and

the diversion of management s attention from other business concerns.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Maritime claimants could arrest the vessels carrying our cargoes.

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

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

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

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

The terms of our indebtedness may limit our ability to borrow additional funds or capitalize on business opportunities. In addition, our future debt level may limit our future financial and operating flexibility.

As of December 31, 2007, our consolidated debt outstanding was approximately \$3.6 billion, consisting of approximately \$2.6 billion principal amount of long-term debt (including senior notes) and approximately \$1.0 billion of short-term borrowings. As of December 31, 2007, we had \$1.0 billion of available borrowing capacity under our senior unsecured revolving credit facility.

The amount of our current or future indebtedness could have significant effects on our operations, including, among other things:

- a significant portion of our cash flow will be dedicated to the payment of principal and interest on our indebtedness and may not be available for other purposes, including the payment of distributions on our units and capital expenditures;
- credit rating agencies may view our debt level negatively;
- covenants contained in our existing debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;
- our ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership purposes may be limited;
- we may be at a competitive disadvantage relative to similar companies that have less debt; and
- we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level.

Our credit agreements prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, the agreements contain various covenants limiting our ability to, among other things, incur indebtedness if certain financial ratios are not maintained, grant liens, engage in transactions with affiliates, enter into sale-leaseback transactions, and sell substantially all of our assets or enter into a merger or consolidation. Our credit facility treats a change of control as an event of default and also requires us to maintain a certain debt coverage ratio. Our senior notes do not restrict distributions to unitholders, but a default under our credit agreements will be treated as a default under the senior notes. Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Facilities and Long-Term Debt.

Our ability to access capital markets to raise capital on favorable terms will be affected by our debt level, our operating and financial performance the amount of our debt maturing in the next several years and current maturities and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, then we could experience an increase in our borrowing costs, face difficulty accessing capital markets or incurring additional indebtedness, be unable to receive open credit from our suppliers and trade counterparties, be unable to benefit from swings in market prices and shifts in market structure during periods of volatility in the crude oil market or suffer a reduction in the market price of our common units. If we are unable to access the capital markets on favorable terms at the time a debt obligation becomes due in the future, we might be forced to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected rates.

Increases in interest rates could adversely affect our business and the trading price of our units.

We use both fixed and variable rate debt, and we are exposed to market risk due to the floating interest rates on our credit facilities. As of December 31, 2007, we had approximately $3.6 billion of consolidated debt, of which approximately $2.6 billion was at fixed interest rates and approximately $1.0 billion was at variable interest rates (including $80 million of interest rate derivatives that swap fixed-rate debt for floating). From time to time we use interest rate derivatives to hedge interest obligations on specific debt issuances, including anticipated debt issuances. Our results of operations, cash flows and financial position could be adversely affected by significant increases in interest rates above current levels. Additionally, increases in interest rates could adversely affect our marketing segment results by increasing interest costs associated with the storage of hedged crude oil and LPG inventory. Further, the trading price of our common units may be sensitive to changes in interest rates and any rise in interest rates could adversely impact such trading price.

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

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

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

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

An impairment of goodwill could reduce our earnings.

At December 31, 2007, we have $1.1 billion of goodwill, of which we recorded approximately $875 million upon completion of our merger with Pacific. The purchase price for the Pacific merger was approximately $2.5 billion. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the acquired tangible and separately measurable intangible net assets. U.S. generally accepted accounting principles, or GAAP, requires us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. If we were to determine that any of our remaining balance of goodwill was impaired, we would be required to take an immediate charge to earnings with a corresponding reduction of partners equity and increase in balance sheet leverage as measured by debt to total capitalization.

PAA/Vulcan s natural gas storage facilities are new and have limited operating history.

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

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

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

The devotion of capital, management time and other resources to natural gas storage and refined products operations could adversely affect our existing business. The natural gas storage and refined products businesses may involve commercial and operational risks that are greater than we have previously assumed.

Federal, state or local regulatory measures could adversely affect PAA/Vulcan s natural gas storage business.

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

Joint venture and other investment structures can create operational difficulties.

Our natural gas storage operations are conducted through PAA/Vulcan, a joint venture between us and a subsidiary of Vulcan Capital Private Equity I LLC (Vulcan Capital). We are also engaged in an investment arrangement with Settoon Towing. Joint venture arrangements typically include provisions designed to allow each venturer to participate at some level in the management of the venture and to protect such venturer s investment.

As a result, differences in views among the venture participants may result in delayed decisions or in failures to agree on major matters, such as large expenditures or contractual commitments, the construction or acquisition of assets or borrowing money, among others. Delay or failure to agree may prevent action with respect to such matters, even though such action may serve our best interest or that of the venture. Accordingly, delayed decisions and failures to agree can potentially adversely affect the business and operations of the ventures and in turn our business and operations.

From time to time, enterprises in which we have interests may be involved in disputes or legal proceedings which, although not involving a loss contingency to us, may nonetheless have the potential to negatively affect our investment. For example, Settoon Towing is party to a lawsuit involving allegations that a Settoon barge struck a wellhead, causing the release of oil into the Intracoastal Canal.

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

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

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

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

Because distributions on our common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of the general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

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

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

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

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

- generally, if a person acquires 20% or more of any class of units then outstanding other than from our general partner or its affiliates, the units owned by such person cannot be voted on any matter; and

- limitations upon the ability of unitholders to call meetings or to acquire information about our operations, as well as other limitations upon the unitholders ability to influence the manner or direction of management.

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

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

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

- an existing unitholder s proportionate ownership interest in the Partnership will decrease;

- the amount of cash available for distribution on each unit may decrease;

- the relative voting strength of each previously outstanding unit may be diminished; and the market price of the common units may decline.

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

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

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

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

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

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

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

These conflicts may include the following:

- we do not have any employees and we rely solely on employees of the general partner or, in the case of Plains Marketing Canada, employees of PMC (Nova Scotia) Company;

- under our partnership agreement, we reimburse the general partner for the costs of managing and for operating the partnership;

- the amount of cash expenditures, borrowings and reserves in any quarter may affect available cash to pay quarterly distributions to unitholders;

- the general partner tries to avoid being liable for partnership obligations. The general partner is permitted to protect its assets in this manner by our partnership agreement. Under our partnership agreement the general partner would not breach its fiduciary duty by avoiding liability for partnership obligations even if we can obtain more favorable terms without limiting the general partner s liability; under our partnership agreement, the general partner may pay its affiliates for any services rendered on terms fair and reasonable to us. The general partner may also enter into additional contracts with any of its affiliates on behalf of us. Agreements or contracts between us and our general partner (and its affiliates) are not necessarily the result of arms length negotiations; and

- the general partner would not breach our partnership agreement by exercising its call rights to purchase limited partnership interests or by assigning its call rights to one of its affiliates or to us.

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

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

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

Risks Related to an Investment in Our Debt Securities

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

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

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

Our leverage is significant in relation to our partners capital. At December 31, 2007, our total outstanding long-term debt and short-term debt under our revolving credit facility was approximately $3.6 billion. We will be prohibited from making cash distributions during an event of default under any of our indebtedness. Various limitations in our credit facilities may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

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

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

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

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

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

- that subsidiary incurred the guarantee with the intent to hinder, delay or defraud any of its present or future creditors or that subsidiary contemplated insolvency with a design to favor one or more creditors to the total or partial exclusion of others; or

- that subsidiary did not receive fair consideration or reasonable equivalent value for issuing the guarantee and, at the time it issued the guarantee, that subsidiary:

  - was insolvent or rendered insolvent by reason of the issuance of the guarantee;

  - was engaged or about to engage in a business or transaction for which the remaining assets of that subsidiary constituted unreasonably small capital; or

  - intended to incur, or believed that it would incur, debts beyond its ability to pay such debts as they matured.

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

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

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

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

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

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

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

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

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

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

Tax Risks to Common Unitholders

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

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

Current law may change causing us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Specifically, beginning in 2008, we will be subject to a new entity level tax on the portion of our income that is generated in Texas in the prior year. Imposition of any such additional taxes on us will reduce the cash available for distribution to our unitholders. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal income tax purposes, our target distribution amounts will be adjusted to reflect the impact of that law on us.

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

In June 2007, the Canadian government passed legislation that imposes entity-level taxes on certain types of flow-through entities. The legislation refers to safe harbor guidelines that grandfather certain existing entities and delay the effective date of such legislation until 2011 provided that the entities do not exceed the normal growth guidelines. Although limited guidance is currently available, we believe that the legislation will apply to our Canadian partnerships. We believe that we are currently within the normal growth guidelines as defined in the legislation, which should delay the effective date until 2011. However, future acquisitions could be subject to an entity-level tax prior to 2011. Entity-level taxation of our Canadian flow-through entities will reduce cash available for distributions or to pay debt obligations.

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

We will be considered to have been terminated for tax purposes if there are sales or exchanges which, in the aggregate, constitute 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of measuring whether the 50% threshold is reached, multiple sales of the same interest are counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

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

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

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

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

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

If our unitholders sell their common units, they will recognize gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder s allocable share of our net taxable income decrease the unitholder s tax basis in their common units, the amount of any such prior excess distributions with respect to their units will, in effect, become taxable income to the unitholder if the common units are sold at a price greater than the unitholder s tax basis in those common units, even if the price the unitholder receives is less than the unitholder s original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, if a unitholder sells units, the unitholder may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

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

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

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

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

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state, local and foreign taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if our unitholders do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property and conduct business in most states in the United States and Canada, most of which impose a personal income tax on individuals and an income tax on corporations and other entities. It is our unitholders responsibility to file all United States federal, state, local and foreign tax returns.

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

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions.

The tax treatment of (i) publicly traded partnerships or (ii) an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of (i) publicly traded partnerships, including us, or (ii) an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress are considering substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. Although the currently proposed legislation would not appear to affect our treatment as a partnership, we are unable to predict whether any of these changes, or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

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

We will prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

Item 1B. *Unresolved Staff Comments*

None.

Item 3. *Legal Proceedings*

Pipeline Releases. In January 2005 and December 2004, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In late December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains, the EPA, the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 980 and 4,200 barrels were recovered from the two respective sites. The unrecovered oil was removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $4 million to $5 million. In cooperation with the appropriate state and federal environmental authorities, we have substantially completed our work with respect to site restoration, subject to some ongoing remediation at the Pecos River site. EPA has referred these two crude oil releases, as well as several other smaller releases, to the U.S. Department of Justice (the DOJ) for further investigation in connection with a civil penalty enforcement action under the Federal Clean Water Act. We have cooperated in the investigation and are currently involved in settlement discussions with DOJ and EPA. Our assessment is that it is probable we will pay penalties related to the two releases. We may also be subjected to injunctive remedies that would impose additional requirements and constraints on our operations. We have accrued our current estimate of the likely penalties as a loss contingency, which is included in the estimated aggregate costs set forth above. We understand that the maximum permissible penalty, if any, that EPA could assess with respect to the subject releases under relevant statutes would be approximately $6.8 million. We believe that several mitigating circumstances and factors exist that are likely to substantially reduce any penalty that might be imposed by EPA, and will continue to engage in discussions with EPA and the DOJ with respect to such mitigating circumstances and factors, as well as any injunctive remedies proposed.

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

The People of the State of California v. Pacific Pipeline System, LLC (PPS). In March 2005, a release of approximately 3,400 barrels of crude oil occurred on Line 63, subsequently acquired by us in the Pacific merger. The release occurred when Line 63 was severed as a result of a landslide caused by heavy rainfall in the Pyramid Lake area of Los Angeles County. Total projected emergency response, remediation and restoration costs are approximately $26 million, substantially all of which have been incurred. We anticipate that the majority of costs associated with this release will be covered under a pre-existing PPS pollution liability insurance policy. Substantially all of the costs that were incurred as of December 31, 2007 have been recovered under the policy.

In March 2006, PPS, a subsidiary acquired in the Pacific merger, was served with a four count misdemeanor criminal action in the Los Angeles Superior Court Case No. 6NW01020, which alleges the violation by PPS of two strict liability statutes under the California Fish and Game Code for the unlawful deposit of oil or substances harmful to wildlife into the environment, and violations of two sections of the California Water Code for the willful and intentional discharge of pollution into state waters. The fines that can be assessed against PPS for the violations of the strict liability statutes are based, in large measure, on the volume of unrecovered crude oil that was released into the environment, and, therefore, the maximum state fine, if any, that can be assessed is estimated to be approximately $1.4 million in the aggregate. This amount is subject to a downward adjustment with respect to actual volumes of crude oil recovered, and the State of California has the discretion to further reduce the fine, if any, after considering other mitigating factors. Because of the uncertainty associated with these factors, the final amount of the fine that will be assessed for the alleged offenses cannot be ascertained. We will defend against these charges. In addition to these fines, the State of California has indicated that it may seek to recover approximately $150,000 in natural resource damages against PPS in connection with this matter. The mitigating factors may also serve as a basis for a downward adjustment of any natural resource damages amount. We believe that the alleged violations are without merit and intend to defend against them, and that defenses and mitigating factors should apply. We are currently involved in settlement discussions with the State of California.

The EPA has referred this matter to the DOJ for the initiation of proceedings to assess civil penalties against PPS. We understand that the maximum permissible penalty, if any, that the EPA could assess under relevant statutes would be approximately $4.2 million. We believe that several defenses and mitigating circumstances and factors exist that could substantially reduce any penalty that might be imposed by the EPA, and intend to pursue discussions with the EPA regarding such defenses and mitigating circumstances and factors. Because of the uncertainty associated with these factors, the final amount of the penalty that will be claimed by the EPA cannot be ascertained. While we have established an estimated loss contingency for this matter, we are presently unable to determine whether the March 2005 spill incident may result in a loss in excess of our accrual for this matter. Discussions with the DOJ to resolve this matter have commenced.

Pacific Atlantic Terminals. In connection with the Pacific merger, we acquired Pacific Atlantic Terminals LLC (PAT), which is now one of our subsidiaries. PAT owns crude oil and refined products terminals in various locations, including northern California, the Philadelphia, Pennsylvania metropolitan area, and Paulsboro, New Jersey. In the process of integrating PAT s assets into our operations, we identified certain aspects of the operations at the California terminals that appeared to be out of compliance with specifications under the relevant air quality permit. We conducted a prompt review of the circumstances and self-reported the apparent historical occurrences of non-compliance to the Bay Area Air Quality Management District. We have cooperated with the District s review of these matters. Although we are currently unable to determine the outcome of the foregoing, at this time, we do not believe it will have a material impact on our financial condition, results of operations or cash flows.

Exxon v. GATX. This Pacific legacy matter involves the allocation of responsibility for remediation of MTBE contamination at PAT s facility at Paulsboro, New Jersey. The estimated maximum potential remediation cost ranges up to $12 million. Both Exxon and GATX were prior owners of the terminal. We are in dispute with Kinder

Morgan (as successor in interest to GATX) regarding the indemnity by GATX in favor of Pacific in connection with Pacific s purchase of the facility. In a related matter, the New Jersey Department of Environmental Protection has brought suit against GATX and Exxon to recover natural resources damages. Exxon and GATX have filed third-party demands against PAT, seeking indemnity and contribution. We intend to vigorously defend against any claim that PAT is directly or indirectly liable for damages or costs associated with the MTBE contamination.

Other Pacific-Legacy Matters. Pacific had completed a number of acquisitions that had not been fully integrated prior to the merger with Plains. Accordingly, we have and may become aware of other matters involving the assets and operations acquired in the Pacific merger as they relate to compliance with environmental and safety regulations, which matters may result in the imposition of fines and penalties. For example, we were informed by the EPA that a terminal owned by Rocky Mountain Pipeline Systems LLC (RMPS), one of the subsidiaries acquired in the Pacific merger, was purportedly out of compliance with certain regulatory documentation requirements. Upon review, we found similar issues at other RMPS terminals. We have settled these matters with EPA.

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

Environmental. We have in the past experienced and in the future likely will experience releases of crude oil into the environment from our pipeline and storage operations. We also may discover environmental impacts from past releases that were previously unidentified. Although we maintain an inspection program designed to help prevent releases, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business. As we expand our pipeline assets through acquisitions, we typically improve on (decrease) the rate of releases from such assets as we implement our procedures, remove selected assets from service and spend capital to upgrade the assets. See Items 1 and 2. Business and Properties Regulation Pipeline Safety. However, the inclusion of additional miles of pipe in our operations may result in an increase in the absolute number of releases company-wide compared to prior periods. We experienced such an increase in connection with the Pacific acquisition, which added approximately 5,000 miles of pipeline to our operations, and in connection with the purchase of assets from Link Energy LLC in April 2004, which added approximately 7,000 miles of pipeline to our operations. As a result, we have also received an increased number of requests for information from governmental agencies with respect to such releases of crude oil (such as EPA requests under Clean Water Act Section 308), commensurate with the scale and scope of our pipeline operations, including a Section 308 request received in late October 2007 with respect to a 400-barrel release of crude oil, a portion of which reached a tributary of the Colorado River in a remote area of West Texas. See Pipeline Releases above.

At December 31, 2007, our reserve for environmental liabilities totaled approximately $36 million, of which approximately $15 million is classified as short-term and $21 million is classified as long-term. At December 31, 2007, we have recorded receivables totaling approximately $7 million for amounts that are probable of recovery under insurance and from third parties under indemnification agreements.

In some cases, the actual cash expenditures may not occur for three to five years. Our estimates used in these reserves are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional claims. Therefore, although we believe that the reserve is adequate, costs incurred in excess of this reserve may be higher and may potentially have a material adverse effect on our financial condition, results of operations, or cash flows.

Other. A pipeline, terminal or other facility may experience damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. The overall trend in the environmental insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. Absent a material favorable change in the environmental insurance markets, this trend is expected to continue as we continue to grow and expand. As a result, we anticipate that we will elect to self-insure more of our environmental activities or incorporate higher retention in our insurance arrangements.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, we may not be able to maintain adequate insurance in the future at rates we consider reasonable. In addition, although we believe that we have established adequate reserves to the extent that such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial condition, results of operations or cash flows.

Item 4. *Submission of Matters to a Vote of Security Holders*

None.

PART II

Item 5. *Market For Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities*

Our common units are listed and traded on the New York Stock Exchange (NYSE) under the symbol PAA. On February 20, 2008, the closing market price for our common units was $47.24 per unit and there were approximately 69,000 record holders and beneficial owners (held in street name). As of February 20, 2008, there were 115,981,676 common units outstanding.

The following table sets forth high and low sales prices for our common units and the cash distributions declared per common unit for the periods indicated:

	Common Unit Price Range		Cash
	High	Low	Distributions(1)
2007			
4th Quarter	$ 57.09	$ 46.25	$ 0.8500
3rd Quarter	65.24	52.01	0.8400
2nd Quarter	64.82	56.32	0.8300
1st Quarter	59.33	49.56	0.8125
2006			
4th Quarter	$ 53.23	$ 45.20	$ 0.8000
3rd Quarter	47.35	43.21	0.7500
2nd Quarter	48.92	42.81	0.7250

1st Quarter	47.00	39.81	0.7075

(1) Cash distributions for a quarter are declared and paid in the following calendar quarter.

Our common units are used as a form of compensation to our employees. Additional information regarding our equity compensation plans is included in Part III of this report under Item 13. Certain Relationships and Related Transactions, and Director Independence.

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Cash Distribution Policy

We will distribute all of our available cash to our unitholders on a quarterly basis in the manner described below. Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the end of that quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the general partner to:

- provide for the proper conduct of our business;
- comply with applicable law or any partnership debt instrument or other agreement; or
- provide funds for distributions to unitholders and the general partner in respect of any one or more of the next four quarters.

In addition to distributions on its 2% general partner interest, our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, our general partner is entitled, without duplication and except for the agreed upon adjustment discussed below, to 15% of amounts we distribute in excess of $0.450 per unit, 25% of the amounts we distribute in excess of $0.495 per unit and 50% of amounts we distribute in excess of $0.675 per unit.

Upon closing of the Pacific acquisition, our general partner agreed to reduce the amounts due it as incentive distributions. The reduction will be effective for five years, as follows: (i) $5 million per quarter for the first four quarters, (ii) $3.75 million per quarter for the next eight quarters, (iii) $2.5 million per quarter for the next four quarters, and (iv) $1.25 million per quarter for the final four quarters. The total reduction in incentive distributions will be $65 million. The first quarterly reduction took place in connection with the distribution paid in February 2007. Following the distribution in February 2008, the aggregate remaining incentive distribution reduction was $41 million.

We paid $73 million to the general partner in incentive distributions in 2007. On February 14, 2008, we paid a quarterly distribution of $0.85 per unit applicable to the fourth quarter of 2007, of which approximately $25 million was paid to the general partner. See Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner.

Under the terms of the agreements governing our debt, we are prohibited from declaring or paying any distribution to unitholders if a default or event of default (as defined in such agreements) exists. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Facilities and Long-Term Debt.

Issuer Purchases of Equity Securities

We did not repurchase any of our common units during the fourth quarter of fiscal 2007, and we do not have any announced or existing plans to repurchase any of our common units.

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Item 6. ***Selected Financial Data***

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2007, 2006, 2005, 2004 and 2003 and for the years then ended. The selected financial data should be read in conjunction with the Consolidated Financial Statements, including the notes thereto, and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

	Year Ended December 31,				
	2007	2006	2005	2004	2003
	(in millions, except for per unit and volume data)				
Statement of operations data:					
Total revenues(1)	$ 20,394	$ 22,445	$ 31,177	$ 20,975	$ 12,590
Crude oil and LPG purchases and related costs(1)	19,001	21,486	30,443	20,424	12,233
Field operating costs	531	370	273	220	140
General and administrative expenses	164	134	103	83	73
Depreciation and amortization	180	100	84	69	46
Total costs and expenses	19,876	22,090	30,903	20,796	12,492
Operating income	518	355	274	179	98
Interest expense	(162)	(86)	(59)	(47)	(35)
Equity earnings in unconsolidated entities	15	8	2	1	
Interest and other income (expense), net	10	2	1		(4)
Current income tax expense	(3)				
Deferred income tax expense	(13)				
Income before cumulative effect of change in accounting principle(2)	365	279	218	133	59
Cumulative effect of change in accounting principle		6		(3)	
Net income	$ 365	$ 285	$ 218	$ 130	$ 59
Basic net income before cumulative effect of change in accounting principle(2)	$ 2.54	$ 2.84	$ 2.77	$ 1.94	$ 1.01
Diluted net income before cumulative effect of change in accounting principle(2)	$ 2.52	$ 2.81	$ 2.72	$ 1.94	$ 1.00
Basic weighted average number of limited partner units outstanding	113	81	69	63	53
Diluted weighted average number of limited partner units outstanding	114	82	70	63	53
Balance sheet data (at end of period):					
Total assets	$ 9,906	$ 8,715	$ 4,120	$ 3,160	$ 2,096
Total long-term debt	2,624	2,626	952	949	519
Total debt	3,584	3,627	1,330	1,125	646

Partners capital	3,424	2,977	1,331	1,070	747
Other data:					
Maintenance capital expenditures	$ 50	$ 28	$ 14	$ 11	$ 8
Net cash provided by (used in) operating activities(3)	796	(276)	24	104	115
Net cash used in investing activities(3)	(663)	(1,651)	(297)	(651)	(272)
Net cash provided by (used in) financing activities	(124)	1,927	271	555	157
Declared and paid distributions per limited partner unit(4)	3.28	2.87	2.58	2.30	2.19

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	Year Ended December 31,				
	2007	2006	2005	2004	2003
	(in millions, except for per unit and volume data)				
Volumes(5)					
Transportation segment (average daily volumes in thousands of barrels):					
Tariff activities	2,712	2,106	1,799	1,486	902
Trucking	105	101	84	64	52
Transportation Activities Total	2,817	2,207	1,883	1,550	954
Facilities segment:					
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	38	21	17	15	12
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet)	13	13	4		
LPG processing (thousands of barrels per day)	18	12			
Facilities Activities Total (average monthly capacity in millions of barrels)(6)	41	23	18	15	12
Marketing segment (average daily volumes in thousands of barrels):					
Crude oil lease gathering	685	650	610	589	437
Refined products	11	N/A	N/A	N/A	N/A
LPG sales	90	70	56	48	38
Waterborne foreign crude imported	71	63	59	12	N/A
Marketing Activities Total	857	783	725	649	475

(1) Includes gross presentation of buy/sell transactions for all periods prior to the second quarter of 2006. See Note 2 to our Consolidated Financial Statements for further discussion of buy/sell transactions.

(2) Income from continuing operations before cumulative effect of change in accounting principle pro forma for the impact of the January 1, 2006 change in our method of accounting for unit-based payment transactions would have been $224 million, $136 million and $66 million for 2005, 2004 and 2003, respectively. In addition, basic net income per limited partner unit before cumulative effect of change in accounting principle would have been $2.81 ($2.76 diluted), $1.98 ($1.98 diluted) and $1.13 ($1.12 diluted) for 2005, 2004 and 2003, respectively. Income from continuing operations before cumulative effect of change in accounting principle, pro forma for the impact of the January 1, 2004 change in our method of accounting for pipeline linefill in third-party assets, would have been $61 million for 2003. In addition, basic net income per limited partner unit before cumulative effect of change in accounting principle would have been $1.05 ($1.04 diluted) for 2003.

(3) In conjunction with the change in accounting principle we adopted as of January 1, 2004, we have reclassified cash flows for 2003 associated with purchases and sales of linefill on assets that we own as cash flows from investing activities instead of the historical classification as cash flows from operating activities.

(4) Our general partner is entitled, directly or indirectly, to receive 2% proportional distributions, and also incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. See Note 5 to our Consolidated Financial Statements.

(5) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the year.

(6) Calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio; and (iii) LPG and crude processing volumes multiplied by the number of days in the month and divided by 1,000 to convert to monthly capacity in millions.

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical consolidated financial statements and accompanying notes.

Our discussion and analysis includes the following:

- Executive Summary
- Prospects for the Future
- Acquisitions and Internal Growth Projects
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements and Changes in Accounting Principles
- Results of Operations
- Outlook
- Liquidity and Capital Resources
- Off-Balance Sheet Arrangements

Executive Summary

Company Overview

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 (liquefied petroleum gas and other natural gas related petroleum products are collectively referred to as LPG). In addition, through our 50% equity ownership in PAA/Vulcan, we are involved in the development and operation of natural gas storage facilities. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries.

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing. Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and refined products on pipelines, gathering systems, trucks and barges. The transportation segment generates revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees. 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. The facilities segment generates revenue through a combination of month-to-month and multi-year leases and processing arrangements. Our marketing segment operations generally consist of merchant activities associated with the purchase and sale of crude oil, refined products and LPG. 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 potential associated with opportunities inherent in volatile market conditions. These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies to provide a counter-cyclical balance.

Overview of Operating Results, Capital Spending and Significant Activities

During 2007, we recognized net income of $365 million and earnings per diluted limited partner unit of $2.52, compared to net income of $285 million and earnings per diluted limited partner unit of $2.88 during 2006. Net income was $218 million and earnings per diluted limited partner unit was $2.72 for 2005. Key items impacting 2007 include:

Income Statement

- Contributions from the November 2006 Pacific acquisition as well as eight additional acquisitions throughout 2006. We also made four acquisitions during 2007 but their impact on 2007 net income is not material due to their partial year contribution.
- Favorable execution of our risk management strategies around our marketing assets in a market with a high level of crude oil volatility.
- A gain of approximately $12 million on the sale of pipeline linefill.
- A loss of approximately $24 million related to the mark-to-market impact for open derivative instruments (compared to a loss of approximately $4 million for 2006).
- An increase in costs and expenses primarily associated with additional assets resulting from internal growth projects and acquisitions.
- Increased equity compensation plan expense of $49 million (compared to $43 million for 2006), primarily resulting from additional Long-Term Incentive Plan (LTIP) grants.
- Deferred tax expense of approximately $10 million primarily pertaining to recently enacted Canadian tax legislation.

Balance Sheet and Capital Structure

- The completion of four acquisitions in 2007 for aggregate consideration of approximately $123 million.
- Capital expenditures for internal growth projects of $525 million in 2007.
- The sale of approximately 6 million limited partner units in 2007 for net proceeds of approximately $383 million. Our earnings per unit data for 2007 compared to 2006 is also impacted by the sale of approximately 6 million limited partner units in December 2006 (for net proceeds of approximately $306 million) and the November 2006 issuance of approximately 22 million limited partner units (valued at approximately $1.0 billion) in exchange for Pacific limited partner units as part of the Pacific acquisition.

Prospects for the Future

During 2007, we grew our business by expanding our asset base through approximately $123 million of acquisitions and $525 million of internal growth projects. In 2008, we intend to spend approximately $330 million on internal growth projects and also to continue to develop our inventory of projects for implementation beyond 2008. Several of the larger storage tank projects for 2008, such as the construction or expansion of the Patoka and Paulsboro terminals, are well positioned to benefit from the importation of waterborne foreign crude oil into the Gulf Coast as well as the importation of Canadian crude oil. We also believe there are opportunities for us to grow our LPG business. We will continue to look for ways to grow these businesses. We believe we have access to equity and debt capital and that we are well situated to optimize our position in and around our existing assets and to expand our asset base by continuing to consolidate, rationalize and optimize portions of the North American midstream infrastructure.

Although we believe that we are well situated in the North American midstream infrastructure, we face various operational, regulatory, financial and competitive challenges that may impact our ability to execute our strategy as planned. In addition, we operate in a mature industry and believe that acquisitions will play an important role in our potential growth. We will continue to pursue the purchase of midstream assets, and we will also continue to initiate expansion projects designed to optimize product flows in the areas in which we operate. However, we can give no assurance that our current or future acquisition or expansion efforts will be successful. See Item 1A. Risk Factors Risks Related to Our Business.

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Acquisitions and Internal Growth Projects

We completed a number of acquisitions and capital expansion projects in 2007, 2006 and 2005 that have impacted our results of operations and, combined with prudent financing, enabled us to enhance our liquidity, as discussed herein. The following table summarizes our capital expenditures for acquisitions, including investments in unconsolidated entities, internal growth projects and maintenance capital for the periods indicated (in millions):

	For the Year Ended December 31,		
	2007	2006	2005
Acquisition capital	$ 125	$ 3,021	$ 40
Investment in unconsolidated entities	9	44	113
Internal growth projects	525	332	149
Maintenance capital	50	28	14
	$ 709	$ 3,425	$ 316

Internal Growth Projects

As a result of capital expansion opportunities originating from prior acquisitions, we increased our annual level of spending on these projects by approximately 58% in 2007 compared to 2006. Our 2007 projects included the construction and expansion of pipeline systems and crude oil storage and terminal facilities. The following table summarizes our 2007 and 2006 projects (in millions):

Projects	2007	2006
St. James, Louisiana Storage Facility(1)	$ 82	$ 83
Salt Lake City Expansion(1)	72	2
Cheyenne Pipeline	58	10
Patoka Tankage(1)	30	
Cushing Tankage Phase VI(1)	29	10
Martinez Terminal(1)	26	
Elk City to Calumet(1)	14	
Fort Laramie Tank Expansion(1)	12	
Kerrobert Tankage	10	29
Pier 400(2)	6	
Other Projects(3)	186	198
Total	$ 525	$ 332

(1) These projects will continue into 2008 and we expect to incur an additional $105 million to $115 million in 2008 with respect to such projects. See Liquidity and Capital Resources Capital Expenditures and Distributions Paid to Unitholders and General Partners 2008 Capital Expansion Projects.

(2) This project requires approval of a number of city and state regulatory agencies in California. Accordingly, the timing and amount of additional costs, if any, related to Pier 400 are not certain at this time.

(3) Primarily pipeline connections, upgrades and truck stations as well as new tank construction and refurbishing.

Acquisitions

Acquisitions are financed using a combination of equity and debt, including borrowings under our credit facilities and the issuance of senior notes. The businesses acquired impacted our results of operations commencing on the effective date of each acquisition as indicated in the table below. Our ongoing acquisition and capital expansion activities are discussed further in Liquidity and Capital Resources and in Note 3 to our Consolidated Financial Statements.

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2007 Acquisitions

In 2007, we completed four acquisitions for aggregate consideration of approximately $123 million. See Note 3 to our Consolidated Financial Statements. The following table summarizes the acquisitions that were completed in 2007 (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Bumstead LPG Storage Facility	7/24/2007	$ 52	Facilities
Tirzah LPG Storage Facility	10/2/2007	54	Facilities
Other	Various	17	Marketing and Transportation
Total		$ 123	

2006 Acquisitions

In 2006, we completed several acquisitions for aggregate consideration of approximately $3.0 billion. See Note 3 to our Consolidated Financial Statements. The following table summarizes the acquisitions that were completed in 2006, and a description of certain acquisitions follows the table (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Pacific	11/15/2006	$ 2,456	Transportation, Facilities and Marketing
Andrews	4/18/2006	220	Transportation, Facilities and Marketing
SemCrude	5/1/2006	129	Marketing
BOA/CAM/HIPS	7/31/2006	130	Transportation
El Paso-to-Albuquerque Products Pipeline	9/1/2006	66	Transportation
Other	Various	20	Transportation, Facilities and Marketing
Total		$ 3,021	

Pacific. On November 15, 2006 we completed our merger with Pacific pursuant to an Agreement and Plan of Merger dated June 11, 2006. The merger-related transactions included: (i) the acquisition from LB Pacific of the general partner interest and incentive distribution rights of Pacific as well as approximately 5 million Pacific common units and approximately 5 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 common units of the Partnership 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. See Note 3 to our Consolidated Financial Statements for discussion of the purchase price and related allocation, and discussion of the sources of funding.

Other 2006 Acquisitions. In addition, in November 2006, we purchased a 50% interest in Settoon Towing for approximately $34 million. Settoon Towing owns and operates a fleet of 62 transport and storage barges as well as 32 transport tugs. Its core business is the gathering and transportation of crude oil and produced water from inland production facilities across the Gulf Coast.

2005 Acquisitions

We completed six small transactions in 2005 for aggregate consideration of approximately $40 million. The transactions included Canadian crude oil trucking operations and several crude oil pipeline systems along the Gulf Coast as well as in Canada. We also acquired an LPG pipeline and terminal in Oklahoma. These acquisitions did not materially impact our results of operations, either individually or in the aggregate. The following table summarizes the acquisitions that were completed in 2005 (in millions):

Acquisition	Effective Date	Acquisition Price		Operating Segment
Shell Gulf Coast Pipeline Systems(1)	1/1/2005	$	12	Transportation
Tulsa LPG Pipeline	3/2/2005		10	Marketing
Other acquisitions	Various		18	Transportation, Facilities, Marketing
Total		$	40	

(1) The total purchase price was $24 million. A $12 million deposit for the Shell Gulf Coast Pipeline Systems acquisition was paid into escrow in December 2004.

In addition, in September 2005, PAA/Vulcan acquired Energy Center Investments LLC (ECI), an indirect subsidiary of Sempra Energy, for approximately $250 million. ECI develops and operates underground natural gas storage facilities. We own 50% of PAA/Vulcan and the remaining 50% is owned by a subsidiary of Vulcan Capital. We made a $113 million capital contribution to PAA/Vulcan and we account for our investment in PAA/Vulcan under the equity method in accordance with Accounting Principles Board Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock.

Critical Accounting Policies and Estimates

Critical Accounting Policies

We have adopted various accounting policies to prepare our consolidated financial statements in accordance with generally accepted accounting principles in the United States. These critical accounting policies are discussed in Note 2 to the Consolidated Financial Statements.

Critical Accounting Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, as well as the disclosure of contingent assets and liabilities, at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Although we believe these estimates are reasonable, actual results could differ from these estimates. The critical accounting estimates that we have identified are discussed below.

Purchase and Sales Accruals. We routinely make accruals based on estimates for certain components of our revenues and cost of sales due to the timing of compiling billing information, receiving third party information and reconciling our records with those of third parties. Where applicable, these accruals are based on nominated volumes expected to be purchased, transported and subsequently sold. Uncertainties involved in these estimates include levels of production at the wellhead, access to certain qualities of crude oil, pipeline capacities and delivery times, utilization of truck fleets to transport volumes to their destinations, weather, market conditions and other forces beyond our control.

These estimates are generally associated with a portion of the last month of each reporting period. We currently estimate that approximately 3% of total annual revenues and cost of sales are recorded using estimates. Accordingly, a variance from this estimate of 10% would impact the respective line items by less than 1% on an annual basis. In addition, we estimate that less than 5% of total operating income and less than 7% of total net income are recorded using estimates. Although the resolution of these uncertainties has not historically had a material impact on our reported results of operations or financial condition, because of the high volume, low margin nature of our business, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Variances from estimates are reflected in the period actual results become known, typically in the month following the estimate.

Mark-to-Market Accrual. In situations where we are required to mark-to-market derivatives pursuant to Statement of Financial Accounting Standards (SFAS) No. 133 Accounting For Derivative Instruments and Hedging Activities, as amended (SFAS 133), the estimates of gains or losses at a particular period end do not reflect the end results of particular transactions, and will most likely not reflect the actual gain or loss at the conclusion of a transaction. We reflect estimates for these items based on our internal records and information from third parties. A portion of the estimates we use are based on internal models or models of third parties because they are not quoted on a national market. Additionally, values may vary among different models due to a difference in assumptions applied, such as the estimate of prevailing market prices, volatility, correlations and other factors and may not be reflective of the price at which they can be settled due to the lack of a liquid market. Approximately 1% of total annual revenues are based on estimates derived from these models. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Accruals and Contingent Liabilities. We record accruals or liabilities including, but not limited to, environmental remediation and governmental penalties, insurance claims, asset retirement obligations, taxes and potential legal claims. Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Our estimates are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our environmental remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment, costs of medical care associated with worker s compensation and employee health insurance claims, and the possibility of existing legal claims giving rise to additional claims. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. A variance of 5% in our aggregate estimate for the contingent liabilities discussed above would have an approximate $5 million impact on earnings. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets. In conjunction with each acquisition, we must allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. We also estimate the amount of transaction costs that will be incurred in connection with each acquisition. As additional information becomes available, we may adjust the original estimates within a short time period subsequent to the acquisition. In addition, in conjunction with the adoption of SFAS No. 141 Business Combinations, we are required to recognize intangible assets separately from goodwill. Goodwill and intangible assets with indefinite lives are not amortized but instead are periodically assessed for impairment. The impairment testing entails estimating future net cash flows relating to the asset, based on management s estimate of market conditions including pricing, demand, competition, operating costs and other factors. Intangible assets with finite lives are amortized over the estimated useful life determined by management. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, contracts, and industry expertise involves professional judgment and is ultimately based on acquisition models and management s assessment of the value of the assets acquired and, to the extent available, third party assessments. Uncertainties associated with these estimates include changes in production decline rates, production interruptions, fluctuations in refinery capacity or product slates, economic obsolescence factors in the area and potential future sources of cash flow. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. We perform our goodwill impairment test annually (as of June 30) and when events or changes in circumstances indicate that the carrying value may not be recoverable. We did not have any impairments in 2007, 2006 or 2005. See Note 3 to our Consolidated Financial Statements for discussion of our acquisitions.

Equity Compensation Plan Accruals. We accrue compensation expense for outstanding equity awards granted under our various Long Term Incentive Plans as well as outstanding Class B units of Plains AAP, L.P. Under generally accepted accounting principles, we are required to estimate the fair value of our outstanding equity awards and recognize that fair value as compensation expense over the service period. For equity awards that contain a performance condition, the fair value of the equity award is recognized as compensation expense only if the attainment of the performance condition is considered probable.

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For equity awards granted under our various Long Term Incentive Plans, the total compensation expense recognized over the service period is determined by our unit price on the vesting date (or, in some cases, the average unit price for a range of dates preceding the vesting date) multiplied by the number of equity awards that are vesting, plus our share of associated employment taxes. Uncertainties involved in this estimate include the actual unit price at time of vesting, whether or not a performance condition will be attained and the continued employment of personnel with outstanding equity awards.

For the Class B units of Plains AAP, L.P., the total compensation expense recognized over the service period is equal to the grant date fair value of the Class B units that become earned. The Class B units become earned in 25% increments upon PAA achieving annualized distribution levels of $3.50, $3.75, $4.00 and $4.50 (or, in some cases, within six months thereof). When earned, the Class B units will be entitled to participate in distributions paid by Plains AAP, L.P. in excess of $11 million per quarter. Uncertainties involved in this estimate include the estimated date that PAA will achieve the annualized distribution levels required and the continued employment of personnel who have been awarded Class B units.

We recognized total compensation expense of approximately $49 million in 2007 and $43 million in 2006 related to equity awards granted under our various equity compensation plans. We cannot provide assurance that the actual fair value of our equity compensation awards will not vary significantly from estimated amounts. See Note 10 to our Consolidated Financial Statements.

Property, Plant and Equipment and Depreciation Expense. We compute depreciation using the straight-line method based on estimated useful lives. We periodically evaluate property, plant and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. The evaluation is highly dependent on the underlying assumptions of related cash flows. We consider the fair value estimate used to calculate impairment of property, plant and equipment a critical accounting estimate. In determining the existence of an impairment in carrying value, we make a number of subjective assumptions as to:

- whether there is an indication of impairment;
- the grouping of assets;
- the intention of holding versus selling an asset;
- the forecast of undiscounted expected future cash flow over the asset s estimated useful life; and
- if an impairment exists, the fair value of the asset or asset group.

Impairments were not material in 2007, 2006 and 2005.

Recent Accounting Pronouncements and Changes in Accounting Principles

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements that will impact us, see Note 2 to our Consolidated Financial Statements.

Changes in Accounting Principles

Stock-Based Compensation. In December 2004, Statement of Financial Accounting Standard No. 123 (revised 2004), Share-Based Payment (SFAS 123(R)) was issued, which amends SFAS No. 123, Accounting for Stock-Based Compensation, and establishes accounting for transactions in which an entity exchanges its equity instruments for goods or services. This statement requires that the cost resulting from such share-based payment transactions be recognized in the financial statements at fair value. Following our general partner s adoption of Emerging Issues Task Force Issue No. 04-05, Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights, we are now part of the same consolidated group and thus SFAS 123(R) is applicable to our general partner s long-term incentive plan. We adopted SFAS 123(R) on January 1, 2006 under the modified prospective transition method, as defined in SFAS 123(R), and recognized a gain of approximately $6 million due to the cumulative effect of change in accounting principle. The cumulative effect adjustment represents a decrease to our LTIP life-to-date accrued

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expense and related liability under our previous cash-plan, probability-based accounting model and adjusts our aggregate liability to the appropriate fair-value based liability as calculated under an SFAS 123(R) methodology. Our LTIPs are administered by our general partner. We are required to reimburse all costs incurred by our general partner through LTIP settlements. Our LTIP awards are classified as liabilities under SFAS 123(R) as the awards are primarily paid in cash. Under the modified prospective transition method, we are not required to adjust our prior period financial statements for our LTIP awards.

Purchases and Sales of Inventory with the Same Counterparty. In September 2005, the Emerging Issues Task Force (EITF) issued Issue No. 04-13 (EITF 04-13), Accounting for Purchases and Sales of Inventory with the Same Counterparty. The EITF concluded that inventory purchase and sale transactions with the same counterparty should be combined for accounting purposes if they were entered into in contemplation of each other. The EITF provided indicators to be considered for purposes of determining whether such transactions are entered into in contemplation of each other. Guidance was also provided on the circumstances under which nonmonetary exchanges of inventory within the same line of business should be recognized at fair value. EITF 04-13 became effective in reporting periods beginning after March 15, 2006.

We adopted EITF 04-13 on April 1, 2006. The adoption of EITF 04-13 resulted in inventory purchases and sales under buy/sell transactions, which historically would have been recorded gross as purchases and sales, to be treated as inventory exchanges in our consolidated statements of operations. In conformity with EITF 04-13, prior periods are not affected, although we have parenthetically disclosed prior period buy/sell transactions in our consolidated statements of operations. The treatment of buy/sell transactions under EITF 04-13 reduces both revenues and purchases on our income statement but does not impact our financial position, net income, or liquidity.

Results of Operations

	For the Twelve Months Ended December 31,		
	2007	**2006**	**2005**
		(In millions)	
Transportation segment profit	$ 334	$ 200	$ 170
Facilities segment profit	110	35	15
Marketing segment profit	269	228	175
Total segment profit	713	463	360
Depreciation and amortization	(180)	(100)	(84)
Interest expense	(162)	(86)	(59)
Interest income and other income (expense), net	10	2	1
Income tax expense	(16)		
Income before cumulative effect of change in accounting principle	365	279	218
Cumulative effect of change in accounting principle		6	
Net income	$ 365	$ 285	$ 218

Analysis of Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing.

Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. We define segment profit as revenues and equity earnings in unconsolidated entities less (i) purchases and related costs, (ii) field operating costs and (iii) segment general and administrative (G&A) expenses. Each of the items above excludes depreciation and amortization. As a master limited partnership, we make quarterly distributions of our available cash (as defined in our partnership agreement) to our unitholders. We look at each period s earnings before non-cash depreciation and amortization as an important measure of segment performance.

The exclusion of depreciation and amortization expense could be viewed as limiting the usefulness of segment profit as a performance measure because it does not account in current periods for the implied reduction in value of our capital assets, such as crude oil pipelines and facilities, caused by aging and wear and tear. We compensate for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance investments, which act to partially offset the wear and tear and age-related decline in the value of our principal fixed assets. These maintenance investments are a component of field operating costs included in segment profit or in maintenance capital, depending on the nature of the cost. Maintenance capital, which is deducted in determining available cash, consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are considered expansion capital expenditures, not maintenance capital. Repair and maintenance expenditures associated with existing assets that do not extend the useful life, improve the efficiency, or expand the operating capacity of the asset are charged to expense as incurred. See Note 15 to our Consolidated Financial Statements for a reconciliation of segment profit to consolidated income before cumulative effect of change in accounting principle.

Our segment analysis involves an element of judgment relating to the allocations between segments. 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 or at the same rates as those charged to third-party shippers. Facilities segment services are also obtained at rates generally 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. Inter-segment rates are eliminated in consolidation and we believe that the estimates with respect to these rates are reasonable. We also allocate certain operating expense and general and administrative overhead expenses between segments. We believe that the estimates with respect to these allocations are reasonable.

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Transportation

The following table sets forth our operating results from our transportation segment for the periods indicated:

	Year Ended December 31,			Favorable (Unfavorable)			
				2007-2006		2006-2005	
	2007	2006	2005	$	%	$	%
Operating Results (1) (in millions, except per barrel amounts)							
Revenues							
Tariff activities	$ 654	$ 438	$ 375	$ 216	49%	$ 63	17%
Trucking	117	96	60	21	22%	36	60%
Total transportation revenues	771	534	435	237	44%	99	23%
Costs and Expenses							
Trucking costs	(80)	(71)	(50)	(9)	(13)%	(21)	(42)%
Field operating costs (excluding equity compensation charge)	(288)	(201)	(164)	(87)	(43)%	(37)	(23)%
Equity compensation charge operations(2)	(5)	(5)	(1)		%	(4)	(400)%
Segment G&A expenses (excluding equity compensation charge)(3)	(50)	(43)	(40)	(7)	(16)%	(3)	(8)%
Equity compensation charge general and administrative(2)	(19)	(16)	(11)	(3)	(19)%	(5)	(45)%
Equity earnings in unconsolidated entities	5	2	1	3	150%	1	100%
Segment profit	$ 334	$ 200	$ 170	$ 134	67%	$ 30	18%
Maintenance capital	$ 34	$ 20	$ 9	$ 14	70%	$ 11	122%
Segment profit per barrel	$ 0.34	$ 0.26	$ 0.26	$ 0.08	31%	$	%

	Year Ended December 31,			Favorable (Unfavorable)			
				2007-2006		2006-2005	
	2007	2006	2005	Volumes	%	Volumes	%
Average Daily Volumes (thousands of barrels)(4) Tariff activities							
All American	47	49	51	(2)	(4)%	(2)	(4)%
Basin	378	332	290	46	14%	42	14%
Capline	235	160	132	75	47%	28	21%
Line 63/Line 2000	175	20	N/A	155	775%	20	N/A
Salt Lake City Area Systems	101	14	N/A	87	621%	14	N/A
West Texas/New Mexico Area Systems	386	433	428	(47)	(11)%	5	1%
Manito	73	72	63	1	1%	9	14%

Rangeland	63	24	N/A	39	163%	24	N/A
Refined products	109	24	N/A	85	354%	24	N/A
Other	1,145	978	835	167	17%	143	17%
Tariff activities total	2,712	2,106	1,799	606	29%	307	17%
Trucking	105	101	84	4	4%	17	20%
Transportation activities total	**2,817**	**2,207**	**1,883**	**610**	**28%**	**324**	**17%**

(1) Revenues and costs and expenses include intersegment amounts.

(2) Compensation expense related to our equity compensation plans.

(3) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on management s assessment of the business activities for that period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period.

(4) Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.

Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit generated by our tariff and other fee-related activities depends on the volumes transported on the pipeline and the level of the tariff and other fees charged as well as the fixed and variable field costs of operating the pipeline. Segment profit from our pipeline capacity leases generally reflects a negotiated amount.

Transportation segment profit and segment profit per barrel were impacted by the following for the periods indicated:

Operating Revenues and Volumes. As noted in the table above, our transportation segment revenues and volumes increased for 2007 compared to 2006 and for 2006 compared to 2005. The table below presents the significant variances in revenues (in millions) and average daily volumes (thousands of barrels) between 2007, 2006 and 2005:

	Revenues	Volumes
2007 compared to 2006		
Increase due to:		
Acquisitions(1)	$ 164	541
Basin and Capline Pipeline Systems(2)	30	122
Trucking(3)	21	4
Other(4)	22	(57)
Total variance	$ 237	610
2006 compared to 2005		
Increase due to:		
Acquisitions(1)	$ 33	178
Basin and Capline Pipeline Systems(5)	7	70
Canadian Pipeline Systems(6)	8	(7)
Other(4)	51	83
Total variance	$ 99	324

(1) Revenues and volumes for 2007 and 2006 were impacted by crude oil and refined products pipeline systems acquired or brought into service during 2007 and 2006 (primarily from the 2006 Pacific merger).

(2) The increase in volumes and revenues on the Basin system is primarily a result of new connection points that were constructed and brought online in 2007 as well as an increase in short-haul volumes on the Basin system. The increase in the Capline pipeline system volumes and revenues is primarily related to an existing shipper that

increased its movements of crude in 2007.

(3) Revenues were impacted by higher trucking revenues primarily resulting from an increase in trucking rates during 2007 and trucking businesses that were acquired in 2007 and 2006.

(4) Miscellaneous revenue and volume variances on various other systems.

(5) Volumes and revenues on our Basin and Capline pipeline systems increased in 2006 primarily as a result of multi-year contracts entered into during 2006.

(6) Revenues from some of our Canadian pipeline systems increased in 2006 primarily as a result of the appreciation of the Canadian currency (the Canadian to US dollar exchange rate appreciated to an average of 1.13 to 1 for 2006 compared to an average of 1.21 to 1 in 2005). For 2007 compared to 2006, our revenues

from our Canadian pipeline systems also increased as a result of the appreciation of the Canadian currency but were offset by miscellaneous other variances.

Field Operating Costs. Field operating costs have increased in most categories for 2007 and 2006 as we have continued to grow through acquisitions and expansion projects. The 2007 increased costs primarily relate to (i) payroll and benefits, (ii) maintenance, (iii) utilities, (iv) property taxes and (v) compliance with API 653 and pipeline integrity testing and maintenance requirements.

The most significant cost increases in 2006 compared to 2005 were related to (i) payroll and benefits, (ii) utilities, (iii) pipeline integrity testing and maintenance, and (iv) property taxes.

General and Administrative Expenses. Our G&A expenses were impacted in 2007 and 2006 by the following:

Segment G&A expense increased in 2007 compared to 2006 and in 2006 compared to 2005 primarily as a result of acquisitions and expansion projects.

Equity compensation charges increased approximately $3 million in 2007 compared to 2006 primarily as a result of additional LTIP grants. See Note 10 to our Consolidated Financial Statements.

Equity compensation charges increased approximately $5 million in 2006 over 2005, primarily as a result of an increase in our unit price to $51.20 at December 31, 2006 from $39.57 at December 31, 2005. See Note 10 to our Consolidated Financial Statements.

Equity Earnings. Our transportation segment includes our equity earnings from our investments in Settoon Towing, Butte and Frontier. Barge transportation services are provided by Settoon Towing, in which we own a 50% equity interest. Butte and Frontier are pipeline systems in which we own approximately 22% and 22%, respectively. Our investments in Settoon Towing, Butte and Frontier contributed an aggregate of approximately $5 million, $2 million and $1 million in earnings for 2007, 2006 and 2005, respectively.

Maintenance Capital. For the years ended December 31, 2007, 2006 and 2005, maintenance capital investment for our transportation segment was approximately $34 million, $20 million and $9 million, respectively. The increases are due to our ownership of an increased number of assets and pipeline systems resulting from our continued growth through acquisitions and expansion projects and from general inflationary pressures that have adversely impacted the energy industry.

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Facilities

The following table sets forth our operating results from our facilities segment for the periods indicated:

	Year Ended December 31,			Favorable (Unfavorable)			
				2007-2006		2006-2005	
	2007	2006	2005	$	%	$	%
Operating Results (1) (in millions, except per barrel amounts)							
Storage and terminalling revenues(1)	$ 210	$ 88	$ 42	$ 122	139%	$ 46	110%
Field operating costs (excluding equity compensation charge)	(84)	(39)	(18)	(45)	(115)%	(21)	(117)%
Segment G&A expenses (excluding equity compensation charge)(3)	(18)	(14)	(8)	(4)	(29)%	(6)	(75)%
Equity compensation charge general and administrative(2)	(8)	(6)	(2)	(2)	(33)%	(4)	(200)%
Equity earnings in unconsolidated entities	10	6	1	4	67%	5	500%
Segment profit	$ 110	$ 35	$ 15	$ 75	214%	$ 20	133%
Maintenance capital	$ 10	$ 5	$ 1	$ 5	100%	$ 4	400%
Segment profit per barrel	$ 0.22	$ 0.12	$ 0.07	$ 0.10	83%	$ 0.05	71%

	Year Ended December 31,			Favorable (Unfavorable)			
				2007-2006		2006-2005	
	2007	2006	2005	Volumes	%	Volumes	%
Volumes(4)							
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	38	21	17	17	81%	4	24%
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet)	13	13	4		%	9	225%
LPG and crude processing (thousands of barrels per day)	18	12	N/A	6	50%	12	N/A
Facilities activities total (average monthly capacity in millions of barrels)(5)	41	23	18	18	78%	5	28%

(1) Revenues include intersegment amounts.

(2) Compensation expense related to our equity compensation plans.

(3) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on management s assessment of the business activities for that period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on business activities that exist during each period.

(4) Volumes associated with acquisitions represent total volumes for the number of months we actually owned the assets divided by the number of months in the period.

(5) Calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio; and (iii) LPG processing volumes multiplied by the number of days in the month and divided by 1,000 to convert to monthly capacity in millions.

Facilities segment profit and segment profit per barrel were impacted by the following for the periods indicated:

Operating Revenues and Volumes. As noted in the table above, our facilities segment revenues and volumes increased for 2007 compared to 2006 and for 2006 compared to 2005. The table below presents the significant variances in revenues (in millions) and volumes between 2007, 2006 and 2005:

	Volumes			
	Crude Oil, Refined Products and LPG Storage(1)	**Natural Gas Storage(2)**	**LPG and Crude Processing(3)**	**Revenues**
2007 compared to 2006				
Increase due to:				
Acquisitions(4)	13		6	$ 98
Expansions(5)	2			12
Other	2			12
Total variance	**17**		**6**	**$ 122**
2006 compared to 2005				
Increase due to:				
Acquisitions(6)	2	9	12	$ 26
Expansions(7)	1			2
Other	1			18
Total variance	**4**	**9**	**12**	**$ 46**

(1) Average monthly capacity (in millions of barrels).

(2) Average monthly capacity (in bcf).

(3) Barrels per day (in thousands).

(4) Revenues and volumes were primarily impacted in 2007 by acquisitions. The Pacific acquisition was completed in November 2006 and contributed additional revenues of approximately $75 million and additional volumes of approximately 12 million barrels for 2007 compared to 2006. The acquisition of the Shafter processing facility in April 2006 resulted in additional processing revenues of approximately $19 million (which also reflects an increase in internal fees and a wider market place) and additional volumes of approximately 6,000 barrels per day for 2007 compared to 2006. The Bumstead and Tirzah acquisitions in July 2007 and October 2007, respectively, in the aggregate contributed additional revenues of approximately $4 million and additional volumes of approximately 1 million barrels for 2007.

(5)

Expansion projects also resulted in an increase in revenues and volumes in 2007 compared to 2006. The St. James and Kerrobert expansion projects that were completed during 2007 contributed additional revenues of $10 million and $2 million, respectively, and additional aggregate volumes of approximately 2 million barrels for 2007.

(6) Revenues were primarily impacted in 2006 by acquisitions. The Pacific merger was completed in November 2006 and contributed additional revenues of approximately $12 million and additional volumes of approximately 2 million barrels for 2006 compared to 2005. The acquisition of the Shafter processing facility in April 2006 resulted in additional processing revenues of approximately $13 million and additional volumes of approximately 12 thousand barrels per day for 2006 compared to 2005. The utilization of capacity at the Mobile facility that was acquired from Link in 2004 but not used extensively until 2006 contributed approximately $1 million of additional revenues in 2006 compared to 2005. The acquisition of the Kimball gas storage facility by PAA/Vulcan contributed additional volumes of approximately 9 bcf for 2006 compared to 2005. See Equity Earnings below for discussion of the impact of the additional volumes on our equity earnings from PAA/Vulcan.

(7) Expansion projects also resulted in an increase in revenues in 2006 compared to 2005. The Kerrobert expansion project that was completed during 2006 contributed additional revenues of $2 million and additional volumes of approximately 1 million barrels for 2006.

Field Operating Costs. Our field operating costs were impacted in 2007 and 2006 by the following:

Our continued growth, primarily from the acquisitions completed during 2007 and 2006 and the additional tankage added in 2007 and 2006, is the primary cause of the increase in field operating costs in 2007. Of the total increase for 2007 compared to 2006, $8 million relates to the operating costs (including increased utilities expense) associated with the Shafter processing facility that was acquired through the Andrews acquisition in April 2006, approximately $30 million relates to the operating costs associated with the Pacific acquisition that was completed in November 2006, and $1 million relates to the operating costs associated with the Bumstead and Tirzah acquisitions that were completed in July 2007 and October 2007, respectively. The St. James expansion project contributed approximately $2 million of additional operating costs for 2007 compared to 2006.

The acquisitions completed in 2006 and 2005, and the additional tankage added in 2006 and 2005 is the primary cause of the increase in field operating costs in 2006. Of the total increase, approximately $11 million relates to the operating costs associated with the Shafter processing facility and approximately $5 million relates to the operating costs associated with the Pacific acquisition.

General and Administrative Expenses. Our G&A expenses were impacted in 2007 and 2006 by the following:

Segment G&A expense excluding equity compensation charges increased in 2007 compared to 2006 and in 2006 compared to 2005 primarily as a result of acquisitions and expansions.

Equity compensation charges included in segment G&A expenses increased approximately $2 million in 2007 compared to 2006 principally as a result of additional LTIP grants. See Note 10 to our Consolidated Financial Statements.

Equity compensation charges included in segment G&A expenses increased approximately $4 million in 2006 compared to 2005, primarily as a result of an increase in our unit price to $51.20 at December 31, 2006 from $39.57 at December 31, 2005. See Note 10 to our Consolidated Financial Statements.

Equity Earnings. Our facilities segment also includes our equity earnings from our investment in PAA/Vulcan. Our investment in PAA/Vulcan contributed approximately $4 million in additional earnings for 2007 compared to 2006, reflecting increased value for leased storage. PAA/Vulcan contributed approximately $5 million in additional earnings for 2006 compared to 2005, reflecting increased value for leased storage and additional storage capacity resulting from acquisitions.

Maintenance Capital. For the years ended December 31, 2007, 2006 and 2005, maintenance capital investment for our facilities segment was approximately $10 million, $5 million and $1 million, respectively. The increase in 2007 was primarily due to additional maintenance expenditures arising from the Pacific acquisition. The increase in 2006 was primarily due to additional maintenance expenditures at our Alto and Shafter facilities.

Marketing

Our revenues from marketing activities reflect the sale of gathered and bulk-purchased crude oil, refined products and LPG volumes. These revenues also include the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the purchase and the sale, revenues and costs related to purchases will increase and decrease with changes in market prices. However, the margins related to those purchases and sales will not necessarily have corresponding increases and decreases. We do not anticipate that future changes in revenues will be a primary driver of segment profit. Generally, we expect our segment profit to increase or decrease directionally with increases or decreases in our marketing segment volumes (which consist of (i) lease gathered crude oil volumes, (ii) refined products volumes, (iii) LPG sales volumes and (iv) waterborne foreign crude imported) as well as the overall volatility and strength or weakness of market

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conditions and the allocation of our assets among our various risk management strategies. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. Although we believe that the combination of our lease gathered business and our risk management activities provides a counter-cyclical balance that provides stability in our margins, these margins are not fixed and will vary from period to period.

The following table sets forth our operating results from our marketing segment for the periods indicated:

	Year Ended December 31,			Favorable (Unfavorable) 2007-2006		2006-2005	
	2007	2006	2005	$	%	$	%
	(in millions, except per barrel amounts)						
Operating Results(1)							
Revenues(2)(3)	$ 19,858	$ 22,061	$ 30,893	$ (2,203)	(10)%	$ (8,832)	(29)%
Purchases and related costs(4)(5)	(19,366)	(21,641)	(30,579)	2,275	11%	8,938	29%
Field operating costs (excluding equity compensation charge)	(154)	(137)	(94)	(17)	(12)%	(43)	(46)%
Equity compensation charge operations(6)			(2)		%	2	100%
Segment G&A expenses (excluding equity compensation charge)(7)	(52)	(39)	(33)	(13)	(33)%	(6)	(18)%
Equity compensation charge general and administrative(6)	(17)	(16)	(10)	(1)	(6)%	(6)	(60)%
Segment profit(3)	$ 269	$ 228	$ 175	$ 41	18%	$ 53	30%
SFAS 133 mark-to-market loss(3)	$ (27)	$ (4)	$ (19)	$ (23)	(575)%	$ 15	79%
Maintenance capital	$ 6	$ 3	$ 4	$ 3	100%	$ (1)	(25)%
Segment profit per barrel(8)	$ 0.86	$ 0.80	$ 0.66	$ 0.06	8%	$ 0.14	21%

	Year Ended December 31,			Favorable (Unfavorable) 2007-2006		2006-2005	
	2007	2006	2005	Volumes	%	Volumes	%
	(in thousands of barrels per day)						
Average Daily Volumes(9)							
Crude oil lease gathering	685	650	610	35	5%	40	7%
Refined products	11	N/A	N/A	11	100%	N/A	N/A

LPG sales	90	70	56	20	29%	14	25%
Waterborne foreign crude imported	71	63	59	8	13%	4	7%
Marketing Activities Total	857	783	725	74	9%	58	8%

(1) Revenues and costs include intersegment amounts.

(2) Includes revenues associated with buy/sell arrangements of $4,762 million, and $16,275 million for the years ended December 31, 2006 and 2005, respectively. The previously referenced amounts include certain estimates based on management s judgment; such estimates are not expected to have a material impact on the balances. See Note 2 to our Consolidated Financial Statements.

(3) Amounts related to SFAS 133 are included in revenues and impact segment profit.

(4) Includes purchases associated with buy/sell arrangements of $4,795 million and $16,107 million for the years ended December 31, 2006 and 2005, respectively. These amounts include certain estimates based on management s

judgment; such estimates are not expected to have a material impact on the balances. See Note 2 to our Consolidated Financial Statements.

(5) Purchases and related costs include interest expense on contango inventory purchases of $44 million, $49 million and $24 million for the years ended December 31, 2007, 2006 and 2005, respectively.

(6) Compensation expense related to our equity compensation plans.

(7) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on management s assessment of the business activities for that period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period.

(8) Calculated based on crude oil lease gathered volumes, refined products volumes, LPG sales volumes and waterborne foreign crude volumes.

(9) Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.

Marketing segment profit and segment profit per barrel were impacted by the following for the periods indicated:

Revenues and purchases and related costs. The variances between our revenues and purchases and related costs for 2007, 2006 and 2005 are described below.

Our revenues and purchases and related costs decreased for 2007 compared to 2006 and for 2006 compared to 2005 due to the adoption in the second quarter of 2006 of EITF 04-13. According to EITF 04-13, inventory purchases and sales transactions with the same counterparty should be combined for accounting purposes if they were entered into in contemplation of each other. The adoption of EITF 04-13 in the second quarter of 2006 resulted in inventory purchases and sales under buy/sell transactions, which historically would have been recorded gross as purchases and sales, to be treated as inventory exchanges in our consolidated statements of operations. The treatment of buy/sell transactions under EITF 04-13 reduces both revenues and purchases and related costs on our income statement but does not impact our financial position, net income or liquidity.

Our revenues and purchases and related costs for 2007 increased compared to 2006 and they increased for 2006 compared to 2005 partially due to an increase in the average NYMEX price for crude oil. The NYMEX average was $72.36 for 2007 compared to $66.27 for 2006 and $56.65 for 2005.

Our marketing segment profit was also impacted by the following:

During 2007 and 2006, the crude oil market experienced significantly high volatility in prices and market structure. The NYMEX benchmark price of crude oil ranged from approximately $50 to $99 during 2007 and from approximately $55 to $78 for 2006. The NYMEX WTI crude oil benchmark prices reached a record high of over $99 per barrel in November 2007 (which has been exceeded in 2008). The volatile market allowed us to utilize risk management strategies to optimize and enhance the margins of our gathering and marketing activities. The volatile market also led to favorable basis differentials for various delivery points and grades of crude oil during the first half of 2007. These favorable basis differentials began to narrow during the second half of the year.

From early 2005 through the end of June 2007, the market for crude oil generally was volatile and in contango, meaning that the price of crude oil for future deliveries was higher than current prices. A contango market is favorable to our commercial strategies that are associated with storage tankage as it allows us to simultaneously purchase production at current prices for storage and sell at higher prices for future delivery. In July 2007, the market for crude oil transitioned rapidly to a backwardated market, 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. However, in this environment, there is little incentive to store crude oil as current prices are above future delivery prices. The monthly timespread of prices averaged approximately $0.32 for 2007 ($1.24 contango for the first half of the year compared to $(0.58) backwardation for the second half of the year) versus an average contango spread of $1.22 for 2006 and $0.72 for 2005.

Revenues for 2007 include a mark-to-market loss under SFAS 133 of approximately $27 million compared to a loss of approximately $4 million for 2006 and a loss of approximately $19 million for 2005. These gains or losses are generally offset by physical positions that qualify for the normal purchase and normal sale exclusion under SFAS 133 and thus, are not included in the mark-to-market calculation. See Note 6 to our Consolidated Financial Statements for discussion of our hedging activities.

During 2006 and 2007, we purchased certain crude oil gathering assets and related contracts in South Louisiana, completed the acquisitions of Pacific and Andrews, and purchased a refined products supply and marketing business. These transactions primarily affected our transportation and facilities segment, but also included some marketing activities and opportunities. The integration into our business of these marketing activities precludes specific quantification of relative contribution, but we believe these acquisitions increased segment profit and revenues for our marketing segment.

In 2006, we recognized a $6 million non-cash charge primarily associated with declines in oil prices and other product prices during the third and fourth quarters of 2006 and the related decline in the valuation of working inventory volumes. Approximately $3 million of the charge relates to our crude oil inventory in third-party pipelines and the remainder relates to LPG and other products inventory.

Field operating costs increased in 2007 compared to 2006, primarily as a result of increases in (i) contract transportation as a result of 2006 acquisitions, (ii) fuel costs resulting from higher market prices and (iii) maintenance costs as a result of 2006 acquisitions.

Field operating costs increased in 2006 compared to 2005, primarily as a result of increases in (i) payroll and benefits and contract transportation as a result of 2006 acquisitions, (ii) fuel costs and (iii) maintenance costs.

The increase in general and administrative expenses for 2007 compared to 2006 was primarily the result of increased payroll and benefits (partly due to the retirement of an executive), as well as acquisitions and internal growth.

Equity compensation charges increased approximately $1 million in 2007 compared to 2006 primarily as a result of additional LTIP grants. See Note 10 to our Consolidated Financial Statements.

The increase in general and administrative expenses for 2006 compared to 2005 was primarily the result of an increase in the indirect costs allocated to the marketing segment in 2006 as the operations have grown through acquisitions and internal growth.

Equity compensation charges increased approximately $6 million in 2006 over 2005, primarily as a result of an increase in our unit price to $51.20 at December 31, 2006 from $39.57 at December 31, 2005. See Note 10 to our Consolidated Financial Statements.

Maintenance capital. For the years ended December 31, 2007, 2006 and 2005, maintenance capital investment in our marketing segment was approximately $6 million, $3 million and $4 million, respectively.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense was $180 million for the year ended December 31, 2007, compared to $100 million and $84 million for the years ended December 31, 2006 and 2005, respectively. The increases in 2007 and 2006 related primarily to an increased amount of depreciable assets resulting from our acquisition activities and capital projects. Amortization of debt issue costs was $3 million in 2007, $3 million in 2006 and $3 million in 2005.

Included in depreciation expense for the year ended December 31, 2007 is a net loss of approximately $7 million recognized upon disposition of certain inactive assets compared to a net gain of approximately $2 million for the year ended December 31, 2006 and a net loss of approximately $3 million for the year ended December 31, 2005.

Interest Expense

Interest expense was $162 million for the year ended December 31, 2007, compared to $86 million and $59 million for the years ended December 31, 2006 and 2005, respectively. Interest expense is primarily impacted by:

- our average debt balances;
- the level and maturity of fixed rate debt and interest rates associated therewith;
- market interest rates and our interest rate hedging activities on floating rate debt; and
- interest capitalized on capital projects.

The following table summarizes selected components of our average debt balances (in millions):

	For the Year Ended December 31,					
	2007		2006		2005	
	Total	% of Total	Total	% of Total	Total	% of Total
Fixed rate senior notes(1)	$ 2,625	95%	$ 1,336	92%	$ 891	87%
Borrowings under our revolving credit facilities(2)	150	5%	118	8%	135	13%
Total	$ 2,775		$ 1,454		$ 1,026	

(1) Weighted average face amount of senior notes, exclusive of discounts.

(2) Excludes borrowings under our senior secured hedged inventory facility, allocations of interest related to our inventory stored and capital leases.

The issuance of senior notes and the assumption of Pacific s debt in the fourth quarter of 2006 resulted in an increase in the average amount of longer term and higher cost fixed-rate debt outstanding in 2006 and 2007. The overall higher average debt balances in 2007 and 2006 were primarily related to the portion of our acquisitions that were not financed with equity, coupled with borrowings related to other capital projects. During 2007, 2006 and 2005, the average LIBOR rate was 5.2%, 5.0% and 3.2%, respectively. Our weighted average interest rate, excluding commitment and other fees, was approximately 6.3% in 2007, compared to 6.1% and 5.6% in 2006 and 2005, respectively. The impact of the increased debt balance was an increase in interest expense of $80 million, and the impact of the higher weighted-average interest rate was an increase in interest expense of $4 million. Both of these increases were offset primarily by an increase in capitalized interest of $8 million. The net impact of the items discussed above was an increase in interest expense in 2007 of approximately $76 million.

The higher average debt balance in 2006 as compared to 2005 resulted in additional interest expense of approximately $26 million. Our weighted average interest rate, excluding commitment and other fees, was approximately 6.1% for 2006 compared to 5.6% for 2005. The higher weighted average debt balance rate increased interest expense by approximately $30 million in 2006 compared to 2005. Both of these increases were offset primarily by an increase in capitalized interest of $4 million. The net impact of the items discussed above was an increase in interest expense in 2006 as compared to 2005 of approximately $26 million.

Interest costs attributable to borrowings for inventory stored in a contango market are included in purchases and related costs in our marketing segment profit as we consider interest on these borrowings a direct cost to storing the inventory. These borrowings are primarily under our senior secured hedged inventory facility. These costs were approximately $44 million, $49 million and $24 million for the years ended December 31, 2007, 2006 and 2005, respectively.

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Interest Income and Other, Net

Interest income and other, net increased by approximately $8 million for the year ended December 31, 2007 compared to the year ended December 31, 2006, primarily due to (i) the recognition of a gain of approximately $4 million upon the sale of a portion of our stock ownership in the NYMEX and (ii) the change in fair value of our interest rate swaps.

Income Tax Expense

Our income tax expense increased by approximately $16 million for the year ended December 31, 2007 compared to the year ended December 31, 2006 primarily due to Canadian taxation on certain flow-through entities and the introduction of the Texas margin tax. See Note 7 to our Consolidated Financial Statements for further discussion.

Outlook

This section identifies certain matters of risk and uncertainty that may affect our financial performance and results of operations in the future.

Ongoing Acquisition Activities

Consistent with our business strategy, we are continuously engaged in discussions regarding potential acquisitions of transportation, gathering, terminalling or storage assets and related midstream businesses. These acquisition efforts often involve assets that, if acquired, could have a material effect on our financial condition and results of operations. We also have expanded our efforts 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. For example, during the first quarter of 2007, we acquired a refined products marketing business and during 2006, we acquired refined products transportation and storage assets as well as an interest in a barge transportation entity. Through PAA/Vulcan s acquisition of ECI in 2005, we acquired an interest in a natural gas storage entity. We are engaged in discussions and negotiations with various parties regarding the acquisition of assets and businesses as described above. Even after we have reached agreement on a purchase price with a potential seller, confirmatory due diligence or negotiations regarding other terms of the acquisition can cause discussions to be terminated. Accordingly, we typically do not announce a transaction until after we have executed a definitive acquisition agreement. Although we expect the acquisitions we make to be accretive in the long term, we can give no assurance that our current or future acquisition efforts will be successful, that any such acquisition will be completed on terms considered favorable to us or that our expectations will ultimately be realized. See Item 1A. Risk Factors.

Longer-Term Outlook

Our longer-term outlook, spanning three to five years or more, is influenced by many factors affecting the North American midstream energy sector. Some of the more significant trends and factors relating to crude oil include:

- Continued overall depletion of U.S. crude oil production.

- The continuing convergence of worldwide crude oil supply and demand trends.

- The expected extension of DOT regulations to low stress and gathering pipelines.

- Industry compliance with the DOT s adoption of API 653 for testing and maintenance of storage tanks, which will require significant investments to maintain existing crude oil storage and refined products capacity or, alternatively, will result in a reduction, either temporary or permanent, of existing storage capacity by 2009.

The addition of inspection requirements by EPA for storage tanks not subject to DOT s API 653 requirements.

The expectation of increased crude oil production from certain North American regions (primarily Canadian oil sands and deepwater Gulf of Mexico sources) that will, of economic necessity, compete for U.S. markets currently being supplied by non-North American foreign crude imports.

We believe the collective impact of these trends, factors and developments, many of which are beyond our control, will result in an increasingly volatile crude oil market that is subject to more frequent short-term swings in market prices and grade differentials and shifts in market structure. In an environment of tight supply and demand balances, even relatively minor supply disruptions can cause significant price swings. Conversely, despite a relatively balanced market on a global basis, competition within a given region of the U.S. could cause downward pricing pressure and significantly impact regional crude oil price differentials among crude oil grades and locations. Although we believe our business strategy is designed to manage these trends, factors and potential developments, and that we are strategically positioned to benefit from certain of these developments, there can be no assurance that we will not be negatively affected.

We believe we are well-positioned for the future and that the combination of our current baseline activities, our inventory of expansion capital projects and the typical bolt-on acquisitions that augment our annual capital programs underpin our ability to grow our distribution at attractive rates. We also believe that there will be potentially attractive opportunities for consolidation among both public and private midstream entities over the next three years. See Items 1 and 2. Business and Properties Financial Strategy for a discussion of our targeted credit metrics and credit ratings.

Although our investment in natural gas storage assets is currently relatively small when considering the Partnership s overall size, we intend to grow this portion of our business through future acquisitions and expansion projects. We believe our business strategy and expertise in hydrocarbon storage will allow us to grow our natural gas storage platform and benefit from these trends.

In the first quarter of 2007 we acquired a refined products marketing business and during 2006, we acquired refined products transportation and storage assets. We believe that the refined products business will be driven by increased demand for refined products, growth in the capacity of refineries and increased reliance on imports. We believe that demand for refined products will increase and will likely necessitate construction of additional refined products transportation and storage infrastructure. We intend to grow our asset base in the refined products business through future acquisitions and expansion projects. We also intend to apply our business model to the refined products business by growing the marketing and distribution business to complement our strategically located assets.

Liquidity and Capital Resources

Cash flow from operations and borrowings under our credit facilities are our primary sources of liquidity. At December 31, 2007, we had a working capital deficit of approximately $56 million, approximately $1.0 billion of availability under our committed revolving credit facilities and approximately $0.7 billion of availability under our uncommitted hedged inventory facility. Our working capital decreased approximately $188 million during 2007. See Cash Flow from Operations below, for discussion of the relationship between working capital items and our short-term borrowings. Usage of the credit facilities is subject to ongoing compliance with covenants. We believe we are currently in compliance with all covenants.

Cash Flow from Operations

The crude oil market was in contango for much of 2007, 2006 and 2005. Because we own crude oil storage capacity, during a contango market we can buy crude oil in the current month and simultaneously hedge the crude oil by selling it forward for delivery in a subsequent month. This activity can cause significant fluctuations in our cash flow from operating activities as described below.

The primary drivers of cash flow from our operations are (i) the collection of amounts related to the sale of crude oil and other products, the transportation of crude oil and other products for a fee, and storage and terminalling services, and (ii) the payment of amounts related to the purchase of crude oil and other products and other expenses, principally field operating costs and general and administrative expenses. The cash settlement from the purchase and sale of crude oil during any particular month typically occurs within thirty days from the end of the month, except (i) in the months that we store the purchased crude oil and hedge it by selling it forward for delivery in a subsequent month because of contango market conditions or (ii) in months in which we increase our share of linefill in third party pipelines.

The storage of crude oil in periods of a contango market (when the price of crude oil for future deliveries is higher than current prices) can have a material impact on our cash flows from operating activities. In the month we pay for the stored crude oil, we borrow under our credit facilities (or pay from cash on hand) to pay for the crude oil, which negatively impacts our operating cash flow. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored crude oil. Similarly, but to a lesser extent, the level of LPG and other product inventory stored and held for resale at period end affects our cash flow from operating activities.

In periods when the market is not in contango, we typically sell our crude oil during the same month in which we purchase it and we do not rely on borrowings under our credit facilities to pay for the crude oil. Our accounts payable and accounts receivable generally move in tandem because we make payments and receive payments for the purchase and sale of crude oil in the same month, which is the month following such activity. In periods during which we build inventory or linefill, regardless of market structure, we may rely on our credit facilities to pay for the inventory or linefill.

The crude oil market was in contango for the first six months of 2007 and for much of 2006 and 2005. In July 2007, the market for crude oil transitioned rapidly to a backwardated market, meaning that the price of crude oil for future deliveries is lower than current prices. The wide contango spreads experienced over the last couple of years, combined with the level of price structure volatility during that time period, has had a favorable impact on our results. If the market remains in the slightly backwardated to transitional structure that has generally prevailed since July 2007, our future results from our marketing segment may be less than those generated during the more favorable contango market conditions that prevailed throughout most of 2005 and 2006 and the first half of 2007.

Our cash flow provided by operating activities in 2007 was $796 million compared to cash used in operating activities of $276 million in 2006. This change reflects cash generated by our recurring operations offset by a decrease in certain working capital items of approximately $190 million. In 2006, the market was in contango and we increased our storage of crude oil and other products (financed through borrowings under our credit facilities), resulting in a negative impact on our cash flows from operating activities for the period, as explained above. In 2007, the market transitioned and moved into backwardation. As a result, we liquidated most of our crude oil and other product inventories, which led to a positive impact on our cash flow from operating activities. The fluctuations in accounts receivable and other, accounts payable and other current liabilities and short-term debt are primarily related to purchases and sales of crude oil that generally vary proportionately as discussed above.

Our cash flow used in operating activities in 2006 was $276 million compared to cash provided by operating activities of $24 million in 2005. This change reflects cash generated by our recurring operations offset by an increase in certain working capital items of approximately $703 million. In 2006, the market was in contango and we increased our storage of crude oil and other products primarily financed through borrowings under our credit facilities, resulting in a negative impact on our cash flows from operating activities for the period, as explained above. The fluctuations in accounts receivable and other and accounts payable and other current liabilities are primarily related to purchase and sales of crude oil that generally vary proportionately.

Cash flow provided by operating activities was $24 million in 2005 and reflects cash generated by our recurring operations (as indicated above in describing the primary drivers of cash generated from operations), offset by changes in components of working capital, including an increase in inventory. A significant portion of the increased inventory was purchased and stored due to contango market conditions and was paid for during the period via borrowings under our credit facilities or from cash on hand. As mentioned above, this activity has a negative impact in the period that we pay for and store the inventory. In addition, there was a change in working capital resulting from higher NYMEX margin deposits paid during 2005 that had a negative impact on our cash flows from operations. The fluctuations in accounts receivable and other and accounts payable and other current liabilities are primarily related to purchases and sales of crude oil that generally vary proportionately.

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Cash Provided by Equity and Debt Financing Activities

We periodically access the capital markets for both equity and debt financing. We have filed with the Securities and Exchange Commission a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue from time to time up to an aggregate of $2.0 billion of debt or equity securities. At December 31, 2007, we have approximately $0.8 billion of unissued securities remaining available under this registration statement.

Cash used in financing activities was $124 million for 2007 compared to cash provided by financing activities of $1,927 million and $271 million for 2006 and 2005, respectively. Our financing activities primarily relate to funding acquisitions and internal capital projects, and short-term working capital and hedged inventory borrowings related to our contango market activities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under our credit facilities.

Equity Offerings. During the last three years we completed several equity offerings as summarized in the table below (net proceeds in millions). Certain of these offerings involved related parties. See Note 9 to our Consolidated Financial Statements.

2007			2006			2005		
Units	Net Proceeds(1)		Units	Net Proceeds(1)(2)		Units	Net Proceeds(1)	
6,296,172	$	383	6,163,960	$	306	5,854,000	$	242
			3,720,930		163	575,000		22
			3,504,672		152		$	264
				$	621			

(1) Includes our general partner s proportionate capital contribution and is net of costs associated with the offering.

(2) Excludes the common units issued and our general partner s proportionate capital contribution of $22 million pertaining to the equity exchange for the Pacific acquisition.

Senior Notes and Credit Facilities. During the three years ended December 31, 2007 we completed the sale of senior unsecured notes as summarized in the table below (in millions).

Year	Description	Maturity	Face Value		Net Proceeds(1)	
2007	No Senior Notes issued	N/A	N/A			N/A
2006	6.125% Senior Notes issued at 99.56% of face value	Jan 2017	$	400	$	398
	6.65% Senior Notes issued at 99.17% of face value	Jan 2037	$	600	$	595
	6.7% Senior Notes issued at 99.82% of face value	May 2036	$	250	$	250
2005	5.25% Senior Notes issued at 99.5% of face value	Jun 2015	$	150	$	149

(1) Face value of notes less the applicable discount (before deducting for initial purchaser discounts, commissions and offering expenses).

During the year ended December 31, 2007, we had net working capital and hedged inventory repayments of approximately $54 million. These repayments resulted primarily from sales of crude oil inventory that was stored and subsequently liquidated as we transitioned to backwardated market conditions, partially offset by higher levels of stored LPG inventory. See Cash Flow from Operations above. During 2007, we had no borrowings or repayments on our long-term revolving credit facility compared to net repayments for 2006 and 2005 of $299 million and $143 million, respectively. During 2006, we had net working capital and hedged inventory borrowings of approximately $619 million and during 2005 we had net borrowings of approximately $206 million. For further discussion related to our credit facilities and long-term debt, see Credit Facilities and Long-Term Debt below.

Capital Expenditures and Distributions Paid to Unitholders and General Partner

We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations and the financing activities discussed above. Our primary uses of cash are for our acquisition activities, internal growth projects and distributions paid to our unitholders and general partner. See Acquisitions and Internal Growth Projects. The price of the acquisitions includes cash paid, transaction costs and assumed liabilities and net working capital items. Because of the non-cash items included in the total price of the acquisition and the timing of certain cash payments, the net cash paid may differ significantly from the total price of the acquisitions completed during the year.

Distributions to unitholders and general partner. We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. Total cash distributions made during the last three years were as follows (in millions, except per unit amounts):

	Distributions Paid				Distribution
	Common	General Partner			per Limited Partner
Year	**Units**	**Incentive**	**2%**	**Total**	**unit**
2007	$ 370	$ 73	$ 8	$ 451	$ 3.28
2006	$ 225	$ 33	$ 5	$ 263	$ 2.87
2005	$ 178	$ 15	$ 4	$ 197	$ 2.58

2008 Capital Expansion Projects. Our 2008 capital expansion program includes the following projects with the estimated cost for the entire year (in millions):

Projects	**2008**
Patoka tankage	$ 43
Kerrobert facility	36
Paulsboro tankage	30
Fort Laramie Tank Expansion	22
West Hynes tankage	13
Edmonton tankage and connections	12
Bumstead expansion	10
Pier 400(1)	10
Other Projects(2)	154
Subtotal	$ 330
Maintenance Capital	60
Total	$ 390

(1)

This project requires approval of a number of city and state regulatory agencies in California. Accordingly, the timing and amount of additional costs, if any, related to Pier 400 are not certain at this time.

(2) Primarily pipeline connections, upgrades and truck stations as well as new tank construction and refurbishing.

We believe that we have sufficient liquid assets, cash flow from operations and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. We are subject to business and operational risks, however, that could adversely affect our cash flow. A material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

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Credit Facilities and Long-Term Debt

At December 31, 2007, we had approximately $1.0 billion of available borrowing capacity under our $1.6 billion committed revolving credit facilities and approximately $0.7 billion of availability under our $1.4 billion uncommitted hedged inventory facility. See Note 4 to our Consolidated Financial Statements.

We also have several issues of senior debt outstanding that total $2.6 billion, excluding premium or discount, and range in size from $150 million to $600 million and mature at various dates through 2037. See Note 9 to our Consolidated Financial Statements.

All our notes are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for two subsidiaries with assets regulated by the California Public Utility Commission, and certain minor subsidiaries. See Note 12 to our Consolidated Financial Statements.

Our credit agreements and the indentures governing our senior notes contain cross-default provisions. Our credit agreements prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, the agreements contain various covenants limiting our ability to, among other things:

- incur indebtedness if certain financial ratios are not maintained;
- grant liens;
- engage in transactions with affiliates;
- enter into sale-leaseback transactions; and
- sell substantially all of our assets or enter into a merger or consolidation.

Our senior unsecured revolving credit facility treats a change of control as an event of default and also requires us to maintain a debt coverage ratio that will not be greater than 4.75 to 1.0 on all outstanding debt and 5.50 to 1.0 on outstanding debt during an acquisition period (generally, the period consisting of three fiscal quarters following an acquisition greater than $50 million).

For covenant compliance purposes, letters of credit and borrowings to fund hedged inventory and margin requirements are excluded when calculating the debt coverage ratio.

A default under our credit facility would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit agreements, our ability to make distributions of available cash is not restricted. We are currently in compliance with the covenants contained in our credit agreements and indentures.

Contingencies

See Note 11 to our Consolidated Financial Statements.

Commitments

Contractual Obligations. In the ordinary course of doing business we purchase crude oil and LPG from third parties under contracts, the majority of which range in term from thirty-day evergreen to three years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between crude oil and LPG purchases and sales and future delivery obligations. The table below includes purchase obligations related to these activities. Where applicable, the amounts presented represent the net obligations associated with buy/sell contracts and those subject to a net settlement arrangement with the counterparty. We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to creditworthy entities.

The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of December 31, 2007 (in millions).

	Total	2008	2009	2010	2011	2012	2013 and Thereafter
Long-term debt and interest payments(1)	$ 5,013	$ 167	$ 339	$ 159	$ 159	$ 355	$ 3,834
Leases(2)	295	47	41	29	20	15	143
Capital expenditure obligations	17	17					
Other long-term liabilities(3)	100	21	26	33	8	1	11
Subtotal	5,425	252	406	221	187	371	3,988
Crude oil, refined products and LPG purchases(4)	8,163	5,490	948	687	546	487	5
Total	$ 13,588	$ 5,742	$ 1,354	$ 908	$ 733	$ 858	$ 3,993

(1) Includes debt service payments, interest payments due on our senior notes and the commitment fee on our revolving credit facility. Although there is an outstanding balance on our revolving credit facility at December 31, 2007, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no amounts were outstanding on the facility) in the amounts above.

(2) Leases are primarily for office rent and for trucks used in our gathering activities.

(3) Excludes a non-current liability of approximately $22 million related to SFAS 133 included in crude oil and LPG purchases.

(4) Amounts are based on estimated volumes and market prices. The actual physical volume purchased and actual settlement prices may vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with our crude oil marketing, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. At December 31, 2007, we had outstanding letters of credit of approximately $153 million.

Capital Contributions to PAA/Vulcan Gas Storage, LLC. We and Vulcan Gas Storage are both required to make capital contributions in equal proportions to fund equity requests associated with certain projects specified in the joint venture agreement. For certain other specified projects, Vulcan Gas Storage has the right, but not the obligation, to participate for up to 50% of such equity requests. In some cases, Vulcan Gas Storage s obligation is subject to a maximum amount, beyond which Vulcan Gas Storage s participation is optional. For any other capital expenditures, or capital expenditures with respect to which Vulcan Gas Storage s participation is optional, if Vulcan Gas Storage elects not to participate, we have the right to make additional capital contributions to fund 100% of the project until our interest in PAA/Vulcan equals 70%. Such contributions would increase our interest in PAA/Vulcan and dilute Vulcan Gas Storage s interest. Once PAA s ownership interest is 70% or more, Vulcan Gas Storage would have the right, but not the obligation, to make future capital contributions proportionate to its ownership interest at the time. During 2007, we made an additional contribution of $9 million to PAA/Vulcan. Such contribution did not result in an increase to our ownership interest. See Note 8 to our Consolidated Financial Statements.

Distributions. We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. See Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities - Cash Distribution Policy. On February 14, 2008, we paid a cash distribution of $0.85 per unit on all outstanding units. The total distribution paid was approximately $124 million, with approximately $99 million paid to our common unitholders and approximately $25 million paid to our general partner for its general partner interest ($2 million) and incentive distribution interest ($23 million).

Off-Balance Sheet Arrangements

We have invested in certain entities (PAA/Vulcan, Butte, Settoon Towing and Frontier) that are not consolidated in our financial statements. In conjunction with these investments, from time to time we may elect to provide financial and performance guarantees or other forms of credit support. In conjunction with the formation of PAA/Vulcan and the acquisition of ECI, we provided performance and financial guarantees to the seller with respect to PAA/Vulcan s performance under the purchase agreement, as well as in support of continuing guarantees of the seller with respect to ECI s obligations under certain gas storage and other contracts. We believe that the fair value of the obligation to stand ready to perform is minimal. In addition, we believe the probability that we would be required to perform under the guaranty is remote. See Note 9 to our Consolidated Financial Statements for more information concerning our obligations as they relate to our investment in PAA/Vulcan.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

We are exposed to various market risks, including volatility in (i) crude oil, refined products, natural gas and LPG commodity prices, (ii) interest rates and (iii) currency exchange rates. We utilize various derivative instruments to manage such exposure and, in certain circumstances, to realize incremental margin during volatile market conditions. 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 interest rates, currency exchange rates, NYMEX, ICE and over-the-counter positions, and physical volumes, grades, locations and delivery schedules to ensure our hedging activities address our market risks. We have a risk management function that has direct responsibility and authority for our risk policies and our trading controls and procedures and certain 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 gathering and marketing and storage. To hedge the risks discussed above we engage in risk management activities that we categorize by the risks we are hedging. The following discussion addresses each category of risk.

Commodity Price Risk

We hedge our exposure to price fluctuations with respect to crude oil, refined products, natural gas and LPG in storage, and expected purchases and sales of these commodities (relating primarily to crude oil and LPGs at this time). The derivative instruments utilized consist primarily of futures and option contracts traded on the NYMEX, ICE and over-the-counter transactions, including swap and option contracts entered into with financial institutions and other energy companies. Our policy is to purchase only commodity products for which we have a market, and to structure our sales contracts so that price fluctuations for those products do not materially affect the segment profit we receive. Except for the controlled trading program discussed below, we do not acquire and hold futures contracts or other derivative products for the purpose of speculating on price changes, as these activities could expose us to significant losses.

Although we seek to maintain a position that is substantially balanced within our various commodity purchase and sales activities (which mainly relate to crude oil and LPGs), 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.

Although the intent of our risk-management strategies is to hedge our margin, not all of our derivatives qualify for hedge accounting. In such instances, changes in the fair values of these derivatives are recognized in earnings, and result in greater potential for earnings volatility. This accounting treatment is discussed further in Note 2 to our Consolidated Financial Statements.

All of our open commodity price risk derivatives at December 31, 2007 were categorized as non-trading. The fair value of these instruments and the change in fair value that would be expected from a 10 percent price increase are shown in the table below (in millions):

	Fair Value	Effect of 10% Price Increase
Crude oil:		
Futures contracts	$ (8)	$ 14
Swaps and options contracts	(121)	$ (66)
LPG and other:		
Futures contracts	3	$ 6
Swaps and options contracts	88	$ 34
Total Fair Value	$ (38)	

The fair value of futures contracts is based on quoted market prices obtained from the NYMEX or ICE. The fair value of swaps and option contracts is estimated based on quoted prices from various sources such as independent reporting services, industry publications and brokers. These quotes are compared to the contract price of the swap, which approximates the gain or loss that would have been realized if the contracts had been closed out at year end. For positions where independent quotations are not available, an estimate is provided, or the prevailing market price at which the positions could be liquidated is used. The assumptions used in these estimates as well as the source for the estimates are maintained by the independent risk control function. All hedge positions offset physical exposures to the cash market; none of these offsetting physical exposures are included in the above table. Price-risk sensitivities were calculated by assuming an across-the-board 10 percent increase in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10 percent change in prompt month crude prices, the fair value of our derivative portfolio would typically change less than that shown in the table due to lower volatility in out-month prices.

Interest Rate Risk

We use both fixed and variable rate debt, and are exposed to market risk due to the floating interest rates on our credit facilities. Therefore, from time to time we use interest rate derivatives to hedge interest obligations on specific debt issuances, including anticipated debt issuances. All of our senior notes are fixed rate notes and thus not subject to market risk. All of our variable rate debt at December 31, 2007, approximately $1 billion, is short-term debt and is expected to mature in 2008. The average interest rate of 5.5% is based upon rates in effect at December 31, 2007. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates, and the credit spread on outstanding borrowings reflects market. See Note 6 to our Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

Currency Exchange Risk

Our cash flow stream relating to our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. Assets and liabilities of our Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period. Because a significant portion of our Canadian business is conducted in Canadian dollars, we use certain financial instruments to minimize the risks of changes in the exchange rate. These instruments may include forward exchange contracts, swaps and options. The fair value of these instruments based on current termination values is an unrealized loss of $1 million as of December 31, 2007. See Note 6 to our Consolidated Financial Statements for a discussion of our currency exchange rate risk hedging.

Item 8. ***Financial Statements and Supplementary Data***

See Index to the Consolidated Financial Statements on page F-1.

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Item 9. ***Changes In and Disagreements With Accountants on Accounting and Financial Disclosure***

Not applicable.

Item 9A. ***Controls and Procedures***

We maintain written disclosure controls and procedures, which we refer to as our DCP. The purpose of our DCP is to provide reasonable assurance that (i) information is recorded, processed, summarized and reported in time to allow for timely disclosure of such information in accordance with the securities laws and SEC regulations and (ii) information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our DCP as of the end of the period covered by this report, and has found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

In addition to the information concerning our DCP, we are required to disclose certain changes in our internal control over financial reporting. Although we have made various enhancements to our controls, there was no change in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a) are filed with this report as Exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. 1350 are furnished with this report as Exhibits 32.1 and 32.2.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, our Chief Executive Officer and our Chief Financial Officer, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our management, including our Chief Executive Officer and our Chief Financial Officer, has evaluated the effectiveness of our internal control over financial reporting as of December 31, 2007. See Management s Report on Internal Control Over Financial Reporting on page F-2.

Item 9B. ***Other Information***

There was no information that was required to be disclosed in a report on Form 8-K during the fourth quarter of 2007 that has not previously been reported.

PART III

Item 10. *Directors and Executive Officers of Our General Partner and Corporate Governance*

Partnership Management and Governance

As is the case with many publicly traded partnerships, we do not directly have officers, directors or employees. Our operations and activities are managed by Plains All American GP LLC (GP LLC), which employs our management and operational personnel (other than our Canadian personnel, who are employed by PMC (Nova Scotia) Company). GP LLC is the general partner of Plains AAP, L.P. (AAP LP), which is the sole member of PAA GP LLC, our general partner. References to our general partner, as the context requires, include any or all of GP LLC, AAP LP and PAA GP LLC. References to our officers, directors and employees are references to the officers, directors and employees of GP LLC (or, in the case of our Canadian operations, PMC (Nova Scotia) Company).

Our general partner manages our operations and activities. Unitholders are limited partners and do not directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to our unitholders, as limited by our partnership agreement. As a general partner, our general partner is liable for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Our general partner has the sole discretion to incur indebtedness or other obligations on our behalf on a non-recourse basis to the general partner. Our general partner has in the past exercised such discretion and intends to exercise such discretion in the future.

Our partnership agreement provides that our general partner will manage and operate us and that unitholders, unlike holders of common stock in a corporation, will have only limited voting rights on matters affecting our business or governance. The corporate governance of GP LLC is, in effect, the corporate governance of our partnership, subject in all cases to any specific unitholder rights contained in our partnership agreement. References to our Board of Directors mean the board of directors of GP LLC, which consists of up to eight directors elected by the members of GP LLC, and not by our unitholders. The Board currently consists of seven directors. Under the Third Amended and Restated Limited Liability Company Agreement of GP LLC (the GP LLC Agreement), three of the members of GP LLC have the right to designate one director each and our CEO is a director by virtue of holding the office. In addition, the GP LLC Agreement provides that three independent directors (and an eighth seat that is currently vacant) are elected, and may be removed, by a majority of the membership interest. The vacant seat is not required to be independent.

In August 2005, a former member s 19% interest in the general partner was sold pro rata to the other general partner owners, resulting in Vulcan Energy s ownership interest increasing from 44% to 54%. See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters Beneficial Ownership of General Partner Interest. In connection with this transaction, Vulcan Energy entered into an agreement with GP LLC pursuant to which Vulcan Energy has agreed to restrict certain of its voting rights to help preserve a balanced board. Vulcan Energy has agreed that, with respect to any action taken involving the election or removal of an independent director, Vulcan Energy will vote all of its interest in excess of 49.9% in the same way and proportionate to the votes of all membership interests other than Vulcan Energy s. Without the voting agreement, Vulcan Energy s ownership interest would allow Vulcan Energy, in effect, unilaterally to elect five of the eight board seats: the Vulcan Energy designee, the currently vacant seat and the three independent directors (subject, in the case of the independent directors, to the qualification requirements of the GP LLC Agreement, our partnership agreement, NYSE listing standards and SEC regulations). Vulcan Energy has the right at any time to give notice of termination of the voting rights agreement. The time between notice and termination depends on the circumstances, but would never be longer than one year. In connection with the August 2005 transaction, Messrs. Armstrong and Pefanis entered into waivers of the change in control provisions of their employment agreements, which otherwise would have been triggered by the transaction. These waivers were contingent upon Vulcan s execution of the voting agreement, and will terminate upon any breach or termination by Vulcan Energy of, or notice of termination under, the voting agreement. See Item 11. Executive Compensation Employment Contracts and Potential Payments upon Termination or Change-in-Control.

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Another member of GP LLC, Lynx Holdings I, LLC, also agreed to certain restrictions on its voting rights with respect to its approximate 1.2% interest in GP LLC and AAP LP The Lynx voting agreement requires Lynx to vote its membership interest (in the context of elections or the removal of an independent director) in the same way and proportionate to the votes of the other membership interests (excluding Vulcan s and Lynx s). Lynx has the right to terminate its voting agreement at any time upon termination of the Vulcan voting agreement or the sale or transfer of all of its interest in the general partner to an unaffiliated third party.

Non-Management Executive Sessions and Shareholder Communications

Non-management directors meet in executive session in connection with each regular board meeting. Each non-management director acts as presiding director at the regularly scheduled executive sessions, rotating alphabetically by last name.

Interested parties can communicate directly with non-management directors by mail in care of the General Counsel and Secretary or Director of Internal Audit, Plains All American Pipeline, L.P., 333 Clay Street, Suite 1600, Houston, Texas 77002. Such communications should specify the intended recipient or recipients. Commercial solicitations or communications will not be forwarded.

Independence Determinations and Audit Committee

Because we are a limited partnership, the listing standards of the NYSE do not require that we or our general partner have a majority of independent directors or a nominating or compensation committee of the board of directors. We are, however, required to have an audit committee, and all of its members are required to be independent as defined by the NYSE.

Under NYSE listing standards, to be considered independent, our board of directors must determine that a director has no material relationship with us other than as a director. The standards specify the criteria by which the independence of directors will be determined, including guidelines for directors and their immediate family members with respect to employment or affiliation with us or with our independent public accountants.

We have an audit committee that reviews our external financial reporting, engages our independent auditors and reviews the adequacy of our internal accounting controls. The charter of our audit committee is available on our website. See Meetings and Other Information for information on how to access or obtain copies of this charter. The board of directors has determined that each member of our audit committee (Messrs. Goyanes, Smith and Symonds) is (i) independent under applicable NYSE rules and (ii) an Audit Committee Financial Expert, as that term is defined in Item 407 of Regulation S-K.

In determining the independence of the members of our audit committee, the board of directors considered the relationships described below:

Mr. Everardo Goyanes, the chairman of our audit committee, is President and Chief Executive Officer of Liberty Energy Holdings, LLC (LEH), a subsidiary of Liberty Mutual Insurance Company. LEH makes investments in producing properties, from some of which Plains Marketing, L.P. buys the production. LEH does not operate the properties in which it invests. Plains Marketing pays the same amount per barrel to LEH that it pays to other interest owners in the properties. In 2007, the amount paid to LEH by Plains Marketing was approximately $0.5 million (net of severance taxes). The board has determined that the transactions with LEH do not compromise Mr. Goyanes independence.

Mr. Arthur L. Smith, a member of our audit committee, is a nominee for director of Pioneer Southwest Energy Partners, L.P. (PSE). PSE is a subsidiary of Pioneer Natural Resources Company (Pioneer). Pioneer and its affiliates (including PSE) own crude oil producing properties, from some of which Plains Marketing buys the production. Mr. Smith will not be an officer of PSE or Pioneer and will not participate in operational decision making. In 2007, the amount paid to Pioneer and its affiliates by Plains Marketing was approximately $309 million. The board has determined that the transactions with PSE and Pioneer do not compromise Mr. Smith s independence.

Mr. J. Taft Symonds, a member of our audit committee, has no relationships with either GP LLC or us, other than as a director and unitholder.

Compensation Committee

We have a compensation committee that reviews and makes recommendations to the board regarding the compensation for the executive officers and administers our equity compensation plans for officers and key employees. The charter of our compensation committee is available on our website. See Meetings and Other Information for information on how to access or obtain copies of this charter. The compensation committee currently consists of Messrs. Capobianco, Petersen and Sinnott. Under applicable stock exchange rules, none of the members of our compensation committee is required to be independent. None of the members of the compensation committee has been determined to be independent at this time. The compensation committee has the sole authority to retain any compensation consultants to be used to assist the committee, but did not retain any consultants in 2007. Similarly, the compensation committee has not delegated any of its authority to subcommittees. The compensation committee has delegated limited authority to the CEO to administer our long-term incentive plans with respect to non-officers.

Governance and Other Committees

We also have a governance committee that periodically reviews our governance guidelines. The charter of our governance committee is available on our website. See Meetings and Other Information for information on how to access or obtain copies of this charter. The governance committee currently consists of Messrs. Smith and Symonds, each of whom is independent under the NYSE s listing standards. As a limited partnership, we are not required by the listing standards of the NYSE to have a nominating committee. As discussed above, three of the owners of our general partner each have the right to appoint a director, and Mr. Armstrong is a director by virtue of his office. In the event of a vacancy in the three independent director seats, the governance committee will assist in identifying and screening potential candidates. Upon request of the owners of the general partner, the governance committee is also available to assist in identifying and screening potential candidates for the currently vacant at large seat. The governance committee will base its recommendations on an assessment of the skills, experience and characteristics of the candidate in the context of the needs of the board. As a minimum requirement for the independent board seats, any candidate must be independent and qualify for service on the audit committee under applicable SEC and NYSE rules.

In addition, our partnership agreement provides for the establishment or activation of a conflicts committee as circumstances warrant to review conflicts of interest between us and our general partner or the owners of our general partner. Such a committee would consist of a minimum of two members, none of whom can be officers or employees of our general partner or directors, officers or employees of its affiliates nor owners of the general partner interest. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties owed to us or our unitholders.

Meetings and Other Information

During the last fiscal year our board of directors had five regularly scheduled and special meetings, our audit committee had 15 meetings, our compensation committee had one formal meeting and our governance committee had one meeting. None of our directors attended fewer than 75% of the aggregate number of meetings of the board of directors and committees of the board on which the director served.

As discussed above, the corporate governance of GP LLC is, in effect, the corporate governance of our partnership and directors of GP LLC are designated or elected by the members of GP LLC. Accordingly, unlike holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement. As a result, we do not hold annual meetings of unitholders.

All of our committees have charters. Our committee charters and governance guidelines, as well as our Code of Business Conduct and our Code of Ethics for Senior Financial Officers, which apply to our principal executive officer, principal financial officer and principal accounting officer, are available on our Internet website at http://www.paalp.com. Print versions of the foregoing are available to any unitholder upon request by writing to our Secretary, Plains All American Pipeline, L.P., 333 Clay Street, Suite 1600, Houston, Texas 77002. We intend to disclose any amendment to or waiver of the Code of Ethics for Senior Financial Officers and any waiver of our Code of Business Conduct on behalf of an executive officer or director either on our Internet website or in an 8-K filing. Our Chief Executive Officer submitted to the NYSE the most recent annual certification, without qualification, as required by Section 303A.12(a) of the NYSE s Listed Company Manual.

Report of the Audit Committee

The audit committee of Plains All American GP LLC oversees the Partnership s financial reporting process on behalf of the board of directors. Management has the primary responsibility for the financial statements and the reporting process including the systems of internal controls.

In fulfilling its oversight responsibilities, the audit committee reviewed and discussed with management the audited financial statements contained in this Annual Report on Form 10-K.

The Partnership s independent registered public accounting firm, PricewaterhouseCoopers LLP, is responsible for expressing an opinion on the conformity of the audited financial statements with accounting principles generally accepted in the United States of America. The audit committee reviewed with PricewaterhouseCoopers LLP their judgment as to the quality, not just the acceptability, of the Partnership s accounting principles and such other matters as are required to be discussed with the audit committee under generally accepted auditing standards.

The audit committee discussed with PricewaterhouseCoopers LLP the matters required to be discussed by SAS 61 (Codification of Statement on Auditing Standards, AU § 380), as may be modified or supplemented. The committee received written disclosures and the letter from PricewaterhouseCoopers LLP required by Independence Standards Board No. 1, *Independence Discussions with Audit Committees*, as may be modified or supplemented, and has discussed with PricewaterhouseCoopers LLP its independence from management and the Partnership.

Based on the reviews and discussions referred to above, the audit committee recommended to the board of directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2007 for filing with the SEC.

Everardo Goyanes, Chairman
Arthur L. Smith
J. Taft Symonds

Report of the Compensation Committee

The compensation committee of Plains All American GP LLC reviews and makes recommendations to the board of directors regarding the compensation for the executive officers and directors.

In fulfilling its oversight responsibilities, the compensation committee reviewed and discussed with management the compensation discussion and analysis contained in this Annual Report on Form 10-K. Based on the reviews and discussions referred to above, the compensation committee recommended to the board of directors that the compensation discussion and analysis be included in the Annual Report on Form 10-K for the year ended December 31, 2007 for filing with the SEC.

David N. Capobianco, Chairman

Gary R. Petersen
Robert V. Sinnott

Compensation Committee Interlocks and Insider Participation

Messrs. Capobianco, Petersen and Sinnott served on the compensation committee during 2007. During 2007, none of the members of the committee was an officer or employee of us or any of our subsidiaries, or served as an officer of any company with respect to which any of our executive officers served on such company s board of directors. In addition, none of the members of the compensation committee are former employees of ours or any of our subsidiaries. Messrs. Capobianco, Petersen and Sinnott are associated with business entities with which we have relationships. See Item 13. Certain Relationships and Related Transactions, and Director Independence.

Directors, Executive Officers and Other Officers

The following table sets forth certain information with respect to the members of our board of directors, our executive officers (for purposes of Item 401(b) of Regulation S-K) and certain other officers of us and our subsidiaries. Directors are elected annually and all executive officers are appointed by the board of directors. There is no family relationship between any executive officer and director. Three of the owners of our general partner each have the right to separately designate a member of our board. Such designees are indicated in footnote 2 to the following table.

Name	Age (as of 12/31/07)	Position(1)
Greg L. Armstrong*(2)	49	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis*	50	President and Chief Operating Officer
Phillip D. Kramer*	51	Executive Vice President and Chief Financial Officer
W. David Duckett*	52	President -- PMC (Nova Scotia) Company
Mark F. Shires*	50	Senior Vice President Operations
Alfred A. Lindseth	38	Senior Vice President Technology, Process & Risk Management
Al Swanson*	43	Senior Vice President Finance and Treasurer
Stephen L. Bart	47	Vice President Operations of PMC (Nova Scotia) Company
Ralph R. Cross	52	Vice President Business Development and Transportation Services of PMC (Nova Scotia) Company
A. Patrick Diamond	35	Vice President
Lawrence J. Dreyfuss	53	Vice President, General Counsel Commercial & Litigation and Assistant Secretary
Roger D. Everett	62	Vice President Human Resources
James B. Fryfogle	56	Vice President Refinery Supply
Mark J. Gorman	53	Vice President
M.D. (Mike) Hallahan	47	Vice President Crude Oil of PMC (Nova Scotia) Company
Bill Harradence	54	Vice President Human Resources of PMC (Nova Scotia) Company
Richard (Rick) Henson	53	Vice President Corporate Services of PMC (Nova Scotia) Company
Jim G. Hester	48	Vice President Acquisitions
John Keffer	48	Vice President Terminals
Tim Moore*	50	Vice President, General Counsel and Secretary
Daniel J. Nerbonne	50	Vice President Engineering
John F. Russell	59	Vice President West Coast Projects
Robert Sanford	58	Vice President Lease Supply

Tina L. Val*	38	Vice President Accounting and Chief Accounting Officer

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Name	Age (as of 12/31/07)	Position(1)
Troy E. Valenzuela	46	Vice President Environmental, Health and Safety
John P. vonBerg*	53	Vice President Commercial Activities
David E. Wright	62	Vice President
Ron F. Wunder	39	Vice President LPG of PMC (Nova Scotia) Company
David N. Capobianco(2)	38	Director and Member of Compensation** Committee
Everardo Goyanes	63	Director and Member of Audit** Committee
Gary R. Petersen(2)	61	Director and Member of Compensation Committee
Robert V. Sinnott(2)	58	Director and Member of Compensation Committee
Arthur L. Smith	55	Director and Member of Audit and Governance** Committees
J. Taft Symonds	68	Director and Member of Audit and Governance Committees

* Indicates an executive officer for purposes of Item 401(b) of Regulation S-K.

** Indicates chairman of committee.

(1) Unless otherwise described, the position indicates the position held with Plains All American GP LLC.

(2) The GP LLC Agreement specifies that the Chief Executive Officer of the general partner will be a member of the board of directors. The GP LLC Agreement also provides that three of the owners of our general partner each have the right to appoint a member of our board of directors. Mr. Capobianco has been appointed by Vulcan Energy Corporation, of which he is Chairman of the Board. Because it owns a majority in interest in GP LLC, Vulcan Energy Corporation has the power at any time to cause an additional director to be elected to the currently vacant board seat. Mr. Petersen has been appointed by E-Holdings III, L.P., an affiliate of EnCap Investments L.P., of which he is Senior Managing Director. Mr. Sinnott has been appointed by KAFU Holdings, L.P., which is affiliated with Kayne Anderson Investment Management, Inc., of which he is President. See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters Beneficial Ownership of General Partner Interest.

Greg L. Armstrong has served as Chairman of the Board and Chief Executive Officer since our formation in 1998. He has also served as a director of our general partner or former general partner since our formation. In addition, he was President, Chief Executive Officer and director of Plains Resources Inc. from 1992 to May 2001. He previously served Plains Resources as: President and Chief Operating Officer from October to December 1992; Executive Vice President and Chief Financial Officer from June to October 1992; Senior Vice President and Chief Financial Officer from 1991 to 1992; Vice President and Chief Financial Officer from 1984 to 1991; Corporate Secretary from 1981 to 1988; and Treasurer from 1984 to 1987. Mr. Armstrong is also a director of National Oilwell Varco, Inc., a director of BreitBurn Energy Partners, L.P. and a director of PAA/Vulcan.

Harry N. Pefanis has served as President and Chief Operating Officer since our formation in 1998. He was also a director of our former general partner. In addition, he was Executive Vice President Midstream of Plains Resources from May 1998 to May 2001. He previously served Plains Resources as: Senior Vice President from February 1996 until May 1998; Vice President Products Marketing from 1988 to February 1996; Manager of Products Marketing from 1987 to 1988; and Special Assistant for Corporate Planning from 1983 to 1987. Mr. Pefanis was also President of several former midstream subsidiaries of Plains Resources until our formation. Mr. Pefanis is also a director of PAA/Vulcan and Settoon Towing.

Phillip D. Kramer has served as Executive Vice President and Chief Financial Officer since our formation in 1998. In addition, he was Executive Vice President and Chief Financial Officer of Plains Resources from May 1998 to May 2001. He previously served Plains Resources as: Senior Vice President and Chief Financial Officer from May 1997 until May 1998; Vice President and Chief Financial Officer from 1992 to 1997; Vice President from 1988 to 1992; Treasurer from 1987 to 2001; and Controller from 1983 to 1987.

W. David Duckett has been President of PMC (Nova Scotia) Company since June 2003, and Executive Vice President of PMC (Nova Scotia) Company from July 2001 to June 2003. Mr. Duckett was with CANPET Energy Group Inc. from 1985 to 2001, where he served in various capacities, including most recently as President, Chief Executive Officer and Chairman of the Board. Mr. Duckett is also a director of Wellpoint Systems Inc.

Mark F. Shires has served as Senior Vice President Operations since June 2003 and as Vice President Operations from August 1999 to June 2003. He served as Manager of Operations from April 1999 to August 1999. In addition, he was a business consultant from 1996 until April 1999. He served as a consultant to Plains Marketing & Transportation Inc. and Plains All American Pipeline, LP from May 1998 until April 1999. He previously served as President of Plains Terminal & Transfer Corporation, from 1993 to 1996.

Alfred A. Lindseth has served as Senior Vice President Technology, Process & Risk Management since June 2003 and as Vice President Administration from March 2001 to June 2003. He served as Risk Manager from March 2000 to March 2001. He previously served PricewaterhouseCoopers LLP in its Financial Risk Management Practice section as a Consultant from 1997 to 1999 and as Principal Consultant from 1999 to March 2000. He also served GSC Energy, an energy risk management brokerage and consulting firm, as Manager of its Oil & Gas Hedging Program from 1995 to 1996 and as Director of Research and Trading from 1996 to 1997.

Al Swanson has served as Senior Vice President Finance and Treasurer since August 2007. He served as Vice President Finance and Treasurer from August 2005 to August 2007, as Vice President and Treasurer from February 2004 to August 2005 and as Treasurer from May 2001 to February 2004. In addition, he held finance related positions at Plains Resources including Treasurer from February 2001 to May 2001 and Director of Treasury from November 2000 to February 2001. Prior to joining Plains Resources, he served as Treasurer of Santa Fe Snyder Corporation from 1999 to October 2000 and in various capacities at Snyder Oil Corporation including Director of Corporate Finance from 1998, Controller SOCO Offshore, Inc. from 1997, and Accounting Manager from 1992. Mr. Swanson began his career with Apache Corporation in 1986 serving in internal audit and accounting.

Stephen L. Bart has been Vice President, Operations of PMC (Nova Scotia) Company since April 2005 and was Managing Director, LPG Operations & Engineering from February to April 2005. From June 2003 to February 2005, Mr. Bart was engaged as a principal of Broad Quay Development, a consulting firm. From April 2001 to June 2003, Mr. Bart served as Chief Executive Officer of Novera Energy Limited, a publicly-traded international renewable energy concern. From January 2000 to April 2003, he served as Director, Northern Development, for Westcoast Energy Inc.

Ralph R. Cross has been Vice President of Business Development and Transportation Services of PMC (Nova Scotia) Company since July 2001. Mr. Cross was previously with CANPET Energy Group Inc. since 1992, where he served in various capacities, including most recently as Vice President of Business Development.

A. Patrick Diamond has served as Vice President since August 2007. He previously served as Director, Strategic Planning from July 2005 to August 2007 and as Manager Special Projects from June 2001 to July 2005. In addition, he was Manager Special Projects of Plains Resources from August 1999 to June 2001. Prior to joining Plains Resources, Mr. Diamond served Salomon Smith Barney in its Global Energy Investment Banking Group as an Associate from July 1997 to May 1999 and as a Financial Analyst from July 1994 to June 1997.

Lawrence J. Dreyfuss has served as Vice President, General Counsel Commercial & Litigation and Assistant Secretary since August 2006. Mr. Dreyfuss was Vice President, Associate General Counsel and Assistant Secretary of our general partner from February 2004 to August 2006 and Associate General Counsel and Assistant Secretary of our general partner from June 2001 to February 2004 and held a senior management position in the Law Department since May 1999. In addition, he was a Vice President of Scurlock Permian LLC from 1987 to 1999.

Roger D. Everett has served as Vice President Human Resources since November 2006 and as Director of Human Resources from August 2006 to December 2006. Before joining us, Mr. Everett was a Principal with Stone Partners, a human resource management consulting firm, for over 10 years serving as the Managing Director Human Resources from 2000 to 2006. Mr. Everett has held numerous positions of increasing responsibility in human resource management since 1979 including Vice President of Human Resources at Living Centers of America and Beverly Enterprises, Director of Human Resources at Healthcare International and Director of Compensation and benefits at Charter Medical.

James B. Fryfogle has served as Vice President Refinery Supply since March 2005. He served as Vice President Lease Operations from July 2004 until March 2005. Prior to joining us in January 2004, Mr. Fryfogle served as Manager of Crude Supply and Trading for Marathon Ashland Petroleum. Mr. Fryfogle had held numerous positions of increasing responsibility with Marathon Ashland Petroleum or its affiliates or predecessors since 1975.

Mark J. Gorman has served as Vice President since November 2006. Prior to joining Plains, he was with Genesis Energy in differing capacities as a Director, President and CEO, and Executive Vice President and COO from 1996 through August 2006. From 1992 to 1996, he served as a President for Howell Crude Oil Company. Mr. Gorman began his career with Marathon Oil Company, spending 13 years in various disciplines.

M.D. (Mike) Hallahan has served as Vice President, Crude Oil of PMC (Nova Scotia) Company since February 2004 and Managing Director, Facilities from July 2001 to February 2004. He was previously with CANPET Energy Group Inc. where he served in various capacities since 1996, most recently as General Manager, Facilities.

Bill Harradence has served as Vice President, Human Resources of PMC (Nova Scotia) Company since October 2007. Prior to joining PMC, Mr. Harradence served as Vice President of Human Resources and Organizational Development at IHS Energy from February 2005 until October 2007, and prior to that he led Human Resources/EH&S at Aquila Canada for four years. Mr. Harradence has over 25 years of human resources experience including Amoco and Safeway.

Richard (Rick) Henson joined PMC (Nova Scotia) Company in December 2004 as Vice President of Corporate Services. Mr. Henson was previously with Nova Chemicals Corporation, serving in various executive positions from 1999 through 2004, including Vice President, Petrochemicals and Feedstocks, and Vice President, Ethylene and Petrochemicals Business.

Jim G. Hester has served as Vice President Acquisitions since March 2002. Prior to joining us, Mr. Hester was Senior Vice President Special Projects of Plains Resources. From May 2001 to December 2001, he was Senior Vice President Operations for Plains Resources. From May 1999 to May 2001, he was Vice President Business Development and Acquisitions of Plains Resources. He was Manager of Business Development and Acquisitions of Plains Resources from 1997 to May 1999, Manager of Corporate Development from 1995 to 1997 and Manager of Special Projects from 1993 to 1995. He was Assistant Controller from 1991 to 1993, Accounting Manager from 1990 to 1991 and Revenue Accounting Supervisor from 1988 to 1990.

John Keffer has served as Vice President Terminals since November 2006. Mr. Keffer joined Plains Marketing L.P. in October 1998 and prior to his appointment as Vice President, he served as Managing Director Refinery Supply, Director of Trading and Manager of Sales and Trading. Prior to joining Plains, Mr. Keffer was with Prebon Energy, an energy brokerage firm, from January 1996 through September 1998. Mr. Keffer was with the Permian Corporation/Scurlock Permian from January 1990 through December 1995, where he served in several capacities in the marketing department including Director of Crude Oil Trading. Mr. Keffer began his career with Amoco Production Company and served in various capacities beginning in June 1982.

Tim Moore has served as Vice President, General Counsel and Secretary since May 2000. In addition, he was Vice President, General Counsel and Secretary of Plains Resources from May 2000 to May 2001. Prior to joining Plains Resources, he served in various positions, including General Counsel Corporate, with TransTexas Gas Corporation from 1994 to 2000. He previously was a corporate attorney with the Houston office of Weil, Gotshal & Manges LLP. Mr. Moore also has seven years of energy industry experience as a petroleum geologist.

Daniel J. Nerbonne has served as Vice President Engineering since February 2005. Prior to joining us, Mr. Nerbonne was General Manager of Portfolio Projects for Shell Oil Products US from January 2004 to January

2005 and served in various capacities, including General Manager of Commercial and Joint Interest, with Shell Pipeline Company or its predecessors from 1998. From 1980 to 1998 Mr. Nerbonne held numerous positions of increasing responsibility in engineering, operations, and business development, including Vice President of Business Development from December 1996 to April 1998, with Texaco Trading and Transportation or its affiliates.

John F. Russell has served as Vice President West Coast Projects since August 2007. He served as Vice President Pipeline Operations from July 2004 to August 2007. Prior to joining us, Mr. Russell served as Vice President of Business Development & Joint Interest for ExxonMobil Pipeline Company. Mr. Russell had held numerous positions of increasing responsibility with ExxonMobil Pipeline Company or its affiliates or predecessors since 1974.

Robert Sanford has served as Vice President Lease Supply since June 2006. He served as Managing Director Lease Acquisitions and Trucking from July 2005 to June 2006 and as Director of South Texas and Mid Continent Business Units from April 2004 to July 2005. Mr. Sanford was with Link Energy/EOTT Energy from 1994 to April 2004, where he held various positions of increasing responsibility.

Tina L. Val has served as Vice President Accounting and Chief Accounting Officer since June 2003. She served as Controller from April 2000 until she was elected to her current position. From January 1998 to January 2000, Ms. Val served as a consultant to Conoco de Venezuela S.A. She previously served as Senior Financial Analyst for Plains Resources from October 1994 to July 1997.

Troy E. Valenzuela has served as Vice President Environmental, Health and Safety, or EH&S, since July 2002, and has had oversight responsibility for the environmental, safety and regulatory compliance efforts of us and our predecessors since 1992. He was Director of EH&S with Plains Resources from January 1996 to June 2002, and Manager of EH&S from July 1992 to December 1995. Prior to his time with Plains Resources, Mr. Valenzuela spent seven years with Chevron USA Production Company in various EH&S roles.

John P. vonBerg has served as Vice President Commercial Activities since August 2007 and served as Vice President Trading from May 2003 until August 2007. He served as Director of these activities from January 2002 until May 2003. Prior to joining us in January 2002, he was with Genesis Energy in differing capacities as a Director, Vice Chairman, President and CEO from 1996 through 2001, and from 1993 to 1996 he served as a Vice President and a Crude Oil Manager for Phibro Energy USA. Mr. vonBerg began his career with Marathon Oil Company, spending 13 years in various disciplines.

David E. Wright has served as Vice President since November 2006. Prior to joining Plains, he served as Executive Vice President, Corporate Development for Pacific Energy Partners, L.P. from February 2005 and as Vice President, Corporate Development and Marketing from December 2001. Mr. Wright also served as Vice President, Distribution West for Tosco Refining Company from March 1997 to June 2001, and as Vice President, Pipelines for GATX Terminals Corporation from October 1995 to March 1997.

Ron F. Wunder has served as Vice President, LPG of PMC (Nova Scotia) Company since February 2004 and as Managing Director, Crude Oil from July 2001 to February 2004. He was previously with CANPET Energy Group Inc. since 1992, where he served in various capacities, including most recently as General Manager, Crude Oil.

David N. Capobianco has served as a director of our general partner since July 2004. Mr. Capobianco is Chairman of the board of directors of Vulcan Energy Corporation and a Managing Director and co-head of Private Equity of Vulcan Capital, the investment arm of Vulcan Inc., where he has been employed since April 2003. Previously, he served as a member of Greenhill Capital from 2001 to April 2003 and Harvest Partners from 1995 to 2001. Mr. Capobianco is a director of PAA/Vulcan, ICAT Holdings LLC (an insurance holding company), Silvercrest Asset Management Group LLC and Vulcan MLP LLC. Mr. Capobianco received a BA in Economics from Duke University and an MBA from Harvard.

Everardo Goyanes has served as a director of our general partner or former general partner since May 1999. Mr. Goyanes has been President and Chief Executive Officer of Liberty Energy Holdings, LLC (an energy investment firm) since May 2000. From 1999 to May 2000, he was a financial consultant specializing in natural resources. From 1989 to 1999, he was Managing Director of the Natural Resources Group of ING Barings Furman Selz (a banking firm). He was a financial consultant from 1987 to 1989 and was Vice President Finance of Forest

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Oil Corporation from 1983 to 1987. From 1969 to 1982, Mr. Goyanes served in various financial and management capacities at Chase Bank, where his major emphasis was international and corporate finance to large independent and major oil companies. Mr. Goyanes received a BA in Economics from Cornell University and a Masters degree in Finance (honors) from Babson Institute.

Gary R. Petersen has served as a director of our general partner since June 2001. Mr. Petersen is Senior Managing Director of EnCap Investments L.P., an investment management firm which he co-founded in 1988. He is also a director of EV Energy Partners, L.P. He had previously served as Senior Vice President and Manager of the Corporate Finance Division of the Energy Banking Group for RepublicBank Corporation. Prior to his position at RepublicBank, he was Executive Vice President and a member of the Board of Directors of Nicklos Oil & Gas Company from 1979 to 1984. He served from 1970 to 1971 in the U.S. Army as a First Lieutenant in the Finance Corps and as an Army Officer in the Army Security Agency. Mr. Petersen holds MBA and BBA degress from Texas Tech University.

Robert V. Sinnott has served as a director of our general partner or former general partner since September 1998. Mr. Sinnott is President, Chief Investment Officer and Senior Managing Director of energy investments of Kayne Anderson Capital Advisors, L.P. (an investment management firm). He also served as a Managing Director from 1992 to 1996 and as a Senior Managing Director from 1996 until assuming his current role in 2005. He is also President of Kayne Anderson Investment Management, Inc., the general partner of Kayne Anderson Capital Advisors, L.P. and he is a director of Kayne Anderson Energy Development Company. He was Vice President and Senior Securities Officer of the Investment Banking Division of Citibank from 1986 to 1992. Mr. Sinnott received a BA from the University of Virginia and an MBA from Harvard.

Arthur L. Smith has served as a director of our general partner or former general partner since February 1999. Mr. Smith is President and Managing Member of Triple Double Advisors, LLC, an investment advisory firm focused on the energy industry. Mr. Smith was Chairman and CEO of John S. Herold, Inc. (a petroleum research and consulting firm) from 1984 to 2007. From 1976 to 1984, Mr. Smith was a securities analyst with Argus Research Corp., The First Boston Corporation and Oppenheimer & Co., Inc. Mr. Smith holds the CFA designation. He serves on the board of non-profit Dress for Success Houston and the Board of Visitors for the Nicholas School of the Environment and Earth Sciences at Duke University. Mr. Smith received a BA from Duke University and an MBA from NYU s Stern School of Business.

J. Taft Symonds has served as a director of our general partner since June 2001. Mr. Symonds is Chairman of the Board of Symonds Trust Co. Ltd. (a private investment firm) and was, until December 2006, Chairman of the Board of Tetra Technologies, Inc. (an oil and gas services firm). From 1978 to 2004 he was Chairman of the Board and Chief Financial Officer of Maurice Pincoffs Company, Inc. (an international marketing firm). Mr. Symonds has a background in both investment and commercial banking, including merchant banking in New York, London and Hong Kong with Paine Webber, Robert Fleming Group and Banque de la Societe Financiere Europeenne. He is Chairman of the Houston Arboretum and Nature Center. Mr. Symonds received a BA from Stanford University and an MBA from Harvard.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires directors, executive officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC and the NYSE initial reports of ownership and reports of changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms that they file. Such reports are accessible on or through our Internet website at http://www.paalp.com.

Based solely upon a review of the copies of Forms 3, 4 and 5 furnished to us, or written representations from certain reporting persons that no Forms 5 were required, we believe that our executive officers and directors complied with all filing requirements with respect to transactions in our equity securities during 2007.

Item 11. *Executive Compensation*

Compensation Discussion and Analysis

Background

All of our officers and employees (other than Canadian personnel) are employed by Plains All American GP LLC. Our Canadian personnel are employed by PMC (Nova Scotia) Company, which is a wholly owned subsidiary. Under our partnership agreement, we are required to reimburse our general partner and its affiliates for all employment related costs, including compensation for executive officers.

Objectives

Since our inception, we have employed a compensation philosophy that emphasizes pay for performance, both on an individual and entity level, and places the majority of each Named Executive Officer s (defined in the Summary Compensation Table below) compensation at risk. The primary long-term measure of our performance is our ability to increase our sustainable quarterly distribution to our unitholders. We believe our pay-for-performance approach aligns the interests of our executive officers with that of our unitholders, and at the same time enables us to maintain a lower level of base overhead in the event our operating and financial performance is below expectations. Our executive compensation is designed to attract and retain individuals with the background and skills necessary to successfully execute our business model in a demanding environment, to motivate those individuals to reach near-term and long-term goals in a way that aligns their interest with that of our unitholders, and to reward success in reaching such goals. We use three primary elements of compensation to fulfill that design salary, cash bonus and long-term equity incentive awards. Cash bonuses and equity incentives (as opposed to salary) represent the truly performance driven elements. They are also flexible in application and can be tailored to meet our objectives. The determination of specific individuals cash bonuses is based on their relative contribution to achieving or exceeding annual goals and the determination of specific individuals long-term incentive awards is based on their expected contribution in respect of longer term performance benchmarks. We do not maintain a defined benefit or pension plan for our executive officers as we believe such plans primarily reward longevity and not performance. We provide a basic benefits package generally to all employees, which includes a 401(k) plan and health, disability and life insurance. In instances considered necessary for the execution of their job responsibilities, we also reimburse certain of our Named Executive Officers and other employees for club dues and similar expenses. We consider these benefits and reimbursements to be typical of other employers, and we do not believe they are distinctive of our compensation program.

Elements of Compensation

Salary. We do not benchmark our salary or bonus amounts. In practice, we believe our salaries are moderate relative to the broad spectrum of energy industry competitors for similar talent, but are generally competitive with the narrower universe of large-cap MLP peers.

Cash Bonuses. Our cash bonuses consist of annual discretionary bonuses in which all of our current domestic Named Executive Officers potentially participate and a formula-based quarterly bonus program in which Messrs. Coiner and vonBerg were eligible to participate during 2007 and 2006. Mr. Duckett participates in a formula-based quarterly and annual bonus program specific to activities managed by our Canadian personnel.

Long-Term Incentive Awards. The primary long-term measure of our performance is our ability to increase our sustainable quarterly distribution to our unitholders. Historically, we have used performance indexed phantom unit grants to encourage and reward timely achievement of targeted distribution levels and align the long-term interests of our Named Executive Officers with those of our unitholders. These grants also contain minimum service periods as further described below in order to encourage long-term retention. A phantom unit is the right to receive, upon the satisfaction of vesting criteria specified in the grant, a common unit (or cash equivalent). We do not use options as a form of incentive compensation. Unlike vesting of an option, vesting of a phantom unit results in delivery of a common unit or cash of equivalent value as opposed to a right to exercise. Terms of historical phantom unit grants have varied, but generally phantom units vest upon the later of achievement of targeted distribution threshold levels and continued employment for periods ranging from two to six years. These distribution performance thresholds are generally consistent with our targeted range for distribution growth. To encourage accelerated performance, if we meet certain distribution thresholds prior to meeting the minimum service requirement for vesting, our current Named Executive Officers have the right to receive distributions on phantom units prior to vesting in the underlying common units (referred to as distribution equivalent rights, or DERs).

In 2007, the owners of Plains AAP, L.P. authorized the creation of Class B units of Plains AAP, L.P. and authorized GP LLC s compensation committee to issue grants of Class B units to create additional long-term incentives for our management. The entire economic burden of the Class B units, which are equity classified, is borne solely by Plains AAP, L.P. and does not impact our cash or units outstanding. We recognize the grant date fair value of the Class B units as compensation expense over the service period. The expense is also reflected as a capital contribution and thus, results in a corresponding credit to Partners Capital in our Consolidated Financial Statements. We will not be obligated to reimburse Plains AAP, L.P. for such costs and any distributions made on the Class B units will not reduce the amount of cash available for distribution to our unitholders. Each Class B unit represents a profits interest in Plains AAP, L.P., which entitles the holder to participate in future profits and losses from operations, current distributions from operations, and an interest in future appreciation or depreciation in Plains AAP, L.P. s asset values.

The Class B units are subject to restrictions on transfer and are not currently entitled to distributions. Class B units generally become earned (entitled to participate in distributions) in 25% increments when the annualized quarterly distributions on our common units equal or exceed $3.50, $3.75, $4.00 and $4.50 per unit. Upon achievement of these performance thresholds (or, in some cases, within six months thereafter), the Class B units will be entitled to their proportionate share of all quarterly cash distributions made by Plains AAP, L.P. in excess of $11 million per quarter (as adjusted for debt service costs and excluding special distributions funded by debt). Assuming all authorized Class B units are issued, the maximum participation would be 8% of the amount in excess of $11 million per quarter, as adjusted.

To encourage retention following achievement of these performance benchmarks, Plains AAP, L.P. retained a call right to purchase any earned Class B units at a discount to fair market value that is exercisable upon the termination of a holder s employment with Plains All American GP LLC and its affiliates for any reason prior to January 1, 2016, other than a termination of employment by the employee for good reason or by Plains All American GP LLC other than for cause (as defined). Upon the occurrence of a change of control (as defined), (i) all earned units will vest (no longer be subject to Plains AAP, L.P. s call right), and (ii) to the extent any of the units are unearned at the time, an incremental 25% of the units originally awarded will vest. All earned Class B units will also vest if they remain outstanding as of January 1, 2016 or Plains AAP, L.P. elects not to timely exercise its call right. See Item 13. Certain Relationships and Related Transactions, and Director Independence Transactions with Related Persons Our General Partner Class B Units of Plains AAP, L.P.

Relation of Compensation Elements to Compensation Objectives

Our compensation program is designed to motivate, reward and retain our executive officers. Cash bonuses serve as a near-term motivation and reward for achieving the annual goals established at the beginning of each year. Phantom unit awards (and associated DERs) and Class B units provide motivation and reward over both the near-term and long-term for achieving performance thresholds necessary for earning and vesting. The level of annual bonus and phantom unit awards reflect the moderate salary profile and the significant weighting towards performance based, at-risk compensation. Salaries and cash bonuses (particularly quarterly bonuses), as well as currently payable DERs associated with unvested phantom units and earned Class B units subject to Plains AAP, L.P. s call right, serve as near-term retention tools. Longer-term retention is facilitated by the minimum service periods of up to five years associated with phantom unit awards, the long-term (January 2016) vesting profile of the Class B units and, in the case of certain executives directly involved in activities that generate partnership earnings, annual bonuses that are payable over a three-year period. To facilitate Plains All American GP LLC s compensation committee in reviewing and making recommendations, a compensation tally sheet is prepared by Plains All American GP LLC s Chief Executive Officer, or CEO, and General Counsel and provided to the compensation committee.

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We stress performance-based compensation elements to attempt to create a performance driven environment in which our executive officers are (i) motivated to perform over both the short term and the long term, (ii) appropriately rewarded for their services and (iii) encouraged to remain with us even after meeting long-term performance thresholds in order to meet the minimum service periods and by the promise of rewards yet to come. We believe our compensation philosophy as implemented by application of the three primary compensation elements aligns the interests of our Named Executive Officers with our unitholders and positions us to achieve our business goals.

We believe our compensation program has been instrumental to our achievement of stated objectives. Over the five-year period ended December 31, 2007, our annual distribution per common unit has grown at a compound annual rate of 9.2% and the total return realized by our unitholders for that period averaged approximately 24.2%. During this period, we have retained all but one of our Named Executive Officers. As of August 31, 2007, Mr. Coiner (Senior Group Vice President) retired after being with us since our inception. For additional information regarding Mr. Coiner s retirement and related separation agreement, please read Other Compensation Related Matters Former Named Executive Officer below.

Application of Compensation Elements

Salary. We do not make systematic annual adjustments to the salaries of our Named Executive Officers. Instead, when indicated as a result of adding new senior management members to keep pace with our overall growth, necessary salary adjustments are made to maintain hierarchical relationships between senior management levels and the new senior management members. Since the date of our initial public offering (or date of employment, if later), Messrs. Armstrong and Pefanis have each received one salary adjustment, Messrs. Coiner and Kramer each received two salary adjustments, Mr. Duckett has received small salary adjustments in line with other Canadian personnel and Mr. vonBerg has received no salary adjustment.

Annual Discretionary Bonuses. Annual discretionary bonuses are determined based on our performance relative to our annual plan forecast and public guidance, our distribution growth targets and other quantitative and qualitative goals established at the beginning of each year. Such annual objectives are discussed and reviewed with the board of directors in conjunction with the review and authorization of the annual plan.

At the end of each year, the CEO performs a quantitative and qualitative assessment of our performance relative to our goals. Key quantitative measures include earnings before interest, taxes, depreciation and amortization, excluding items affecting comparability (adjusted EBITDA), relative to established guidance, as well as the growth in the annualized quarterly distribution level per common unit relative to annual growth targets. Our primary performance metric is our ability to generate increasing and sustainable cash distributions to our unitholders. Accordingly, although net income and net income per unit are monitored to highlight inconsistencies with primary performance metrics, as is our market performance relative to our MLP peers and major indices, these metrics are considered secondary performance measures. The CEO s written analysis of our performance examines our accomplishments, shortfalls and overall performance against opportunity, taking into account controllable and non-controllable factors encountered during the year.

The resulting document and supporting detail is submitted to the board of directors of Plains All American GP LLC for review and comment. Based on the conclusions set forth in the annual performance review, the CEO submits recommendations to the compensation committee for bonuses to our Named Executive Officers, taking into account the relative contribution of the individual officer. Except as described below for Messrs. Duckett and vonBerg, there are no set formulas for determining the annual discretionary bonus for our Named Executive Officers. Factors considered by the CEO in determining the level of bonus in general include (i) whether or not we achieved the goals established for the year and any notable shortfalls relative to expectations; (ii) the level of difficulty associated with achieving such objectives based on the opportunities and challenges encountered during the year; (iii) current year operating and financial performance relative to both public guidance and prior year s performance; (iv) significant transactions or accomplishments for the period not included in the goals for the year; (v) our relative prospects at the end of the year with respect to future growth and performance; and (vi) our positioning at the end of the year with respect to our targeted credit profile. The CEO takes these factors into consideration as well as the relative contributions of each of our Named Executive Officers to the year s performance in developing his recommendations for bonus amounts.

These recommendations are discussed with the compensation committee, adjusted as appropriate, and submitted to the board of directors for its review and approval. Similarly, the compensation committee assesses the CEO s contribution toward meeting our goals, and recommends a bonus for the CEO it believes to be commensurate with such contribution. In several instances, the CEO (and more recently the President as well) has requested that the bonus amount recommended by the compensation committee be reduced to maintain a closer relationship to bonuses awarded to the other Named Executive Officers. As a result, the current practice is for the CEO to submit to the compensation committee a preliminary draft of bonus recommendations with the amount for the CEO left blank. In the context of discussing and adjusting bonus amounts for other executives set forth in the preliminary draft, the committee and the CEO reach consensus on the appropriate bonus amount for the CEO. The preliminary draft is then revised to include any changes or adjustments, as well as an amount for the CEO, in the formal submittal to the compensation committee for review and recommendation to the board.

U.S. Bonus based on Adjusted EBITDA. Mr. vonBerg and certain other members of our U.S. based senior management team are directly involved in activities that generate partnership earnings. These individuals, along with approximately 110 other employees in our marketing and business development groups participate in a quarterly bonus pool based on adjusted EBITDA, which directly rewards for quarterly performance the commercial and asset managing employees who participate. This quarterly incentive provides a direct incentive to optimize quarterly performance even when, on an annual basis, other factors might negatively affect bonus potential. Allocation of quarterly bonus amounts among all participants based on relative contribution was recommended by Mr. Coiner prior to his retirement effective August 31, 2007 and reviewed, modified and approved by Mr. Pefanis, as appropriate. Following Mr. Coiner s retirement, allocation of quarterly bonus amounts is recommended by Mr. Pefanis and reviewed, modified and approved by Mr. Armstrong, as appropriate. Mr. Pefanis and Mr. Armstrong do not participate in the quarterly bonus. The quarterly bonus amount for Mr. vonBerg is taken into consideration in determining the recommended annual discretionary bonus submitted by the CEO to the compensation committee.

Annual Bonus and Quarterly Bonus based on Adjusted EBITDA (Canada). Substantially all of the personnel employed by PMC (Nova Scotia) Company (including Mr. Duckett) or involved in Canadian operations participate in a bonus pool under a program established at the time of our entry into Canada in 2001 in connection with the CANPET acquisition. The program encompasses a bonus pool consisting of 10% of Adjusted EBITDA for Canadian-based operations (reduced by the carrying cost of inventory in excess of base-level requirements and by the cost of capital associated with growth capital and acquisitions). Participation in the program is recommended by Mr. Duckett and reviewed, adjusted if warranted, and approved by Mr. Pefanis. Mr. Pefanis does not participate in the program. Mr. Duckett receives a quarterly bonus equal to approximately 40% of his participation level for the first three fiscal quarters of the year. He receives an annual bonus consisting of 60% of his participation in the first three quarters and 100% of his participation in the fourth quarter.

Long-Term Incentive Awards. We do not make systematic annual phantom unit awards to our Named Executive Officers. Instead, our objective is to time the granting of awards such that as performance thresholds are met for existing awards, additional long-term incentives are created. Thus, performance is rewarded by relatively greater frequency of awards and lack of performance by relatively lesser frequency of awards. Generally, we believe that a three- to four-year grant cycle (and extended time-vesting requirements) provides a balance between a meaningful retention period for us and a visible, reachable reward for the executive officer. Achievement of performance targets does not shorten the minimum service period requirement. If top performance targets on outstanding awards are achieved in the early part of this four-year cycle, new awards are granted with higher performance thresholds, and the minimum service periods of the new awards are generally synchronized with the remaining time-vesting requirements of outstanding awards in a manner designed to encourage extended retention of our Named Executive Officers.

Accordingly, these new arrangements inherently take into account the value of awards where performance levels have been achieved but have not yet vested due to ongoing service period requirements, but do not take into consideration previous awards that have fully vested.

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As an additional means of providing longer-term, performance-based officer incentives that require extended periods of employment to realize the full benefit, in 2007 the owners of Plains AAP, L.P. authorized the creation of Class B units of Plains AAP, L.P., which the compensation committee of GP LLC is authorized to administer. See Elements of Compensation Long-Term Incentives. These Class B units are limited to 200,000 authorized units, of which approximately 154,000 were issued as of December 31, 2007 pursuant to individual restricted units agreements between Plains AAP, L.P. and certain members of management. Our Named Executive Officers hold 101,000 of the restricted Class B units. The remaining available Class B units are administered at the discretion of the compensation committee and may be awarded upon advancement, exceptional performance or other change in circumstance of an existing member of management, or upon the addition of a new individual to the management team.

Application in 2007

At the beginning of 2007, we publicly established the following five goals for 2007:

1. Deliver operating and financial performance in line with guidance furnished at the beginning of 2007 on a Form 8-K dated February 22, 2007;

2. Successfully integrate the Pacific transaction and realize targeted synergies;

3. Execute planned slate of internal growth projects;

4. Pursue an average of $200 to $300 million of strategic and accretive acquisitions; and

5. Increase our total distributions paid to unitholders in 2007 by at least 14% over 2006 distributions.

We met or substantially exceeded each of these five goals in 2007. Specifically:

Our adjusted EBITDA exceeded the midpoint of the original guidance for 2007 by approximately 13%;

The integration of Pacific was substantially completed in 2007 and targeted synergy levels were achieved;

We began the year with a $500 million capital program that was expanded during the year to $540 million, of which $525 million was incurred;

We completed four strategic and complementary acquisitions totaling $123 million. Excluding the Pacific acquisition completed in 2006, our three year average acquisition expenditures total approximately $300 million per year; and

We paid approximately $3.28 per unit in distributions during 2007, a 14.4% increase over the $2.87 paid per unit in 2006.

For 2007, the elements of compensation were applied as follows:

Salary. No salary adjustments for NEOs were recommended or made in 2007.

Cash Bonuses. Based on the CEO s annual performance review and the individual performance of each of our current Named Executive Officers, the compensation committee recommended to the board of directors and the board of directors approved the annual bonuses reflected in the Summary Compensation Table and notes thereto. Such amounts take into account the performance relative to each of the five goals established for 2007; the absence of any notable shortfalls relative to expectations; the level of difficulty associated with achieving such objectives; our relative positioning at the end of the year with respect to future growth and performance; the significant transactions or accomplishments for the period not included in the goals for the year; and our positioning at the end of the year with respect to our targeted credit profile. In the case of Mr. Duckett, the aggregate bonus amount represented 40% of his participation level for the first three fiscal quarters and an annual payment consisting of 60% of his participation for the first three quarters and 100% of his participation for the fourth quarter. For Mr. vonBerg, the aggregate bonus amount represented 36% in annual bonus and 64% in quarterly bonus. Relative to bonuses awarded for 2006, the 2007 bonus amounts for current Named Executive Officers are approximately 6% lower to 64% higher. Such adjustments take into account individual contributions to overall performance and recognize that, while both 2006 and 2007 were periods of significant accomplishments, the overperformance during 2006 relative to goals and the significant acquisitions, financings and other related activities completed during that period were generally deserving of greater rewards than the accomplishments during 2007.

Long-Term Incentive Awards. Effective with our November 2006 quarterly distribution, we achieved the highest performance threshold ($3.00 per limited partner unit annualized) contained in substantially all outstanding pre-2006 phantom unit awards. Approximately 31% of these pre-2006 awards met the service-period requirement and vested in May 2007. Vesting of the remaining phantom units under these pre-2006 awards remains subject to continued employment, and the service-period vesting requirements will be met in various increments over the next three to four years, with the final vesting in May 2010. The compensation expense recognized in 2007 and 2006 related to such awards is reflected on an individual basis in the Summary Compensation Table below. The vesting requirements are described in the footnotes to the Outstanding Equity Awards Table below.

Consistent with our policy of issuing new grants (with extended time-vesting periods) when the highest performance threshold of existing grants has been reached, in February 2007, the board of directors granted awards with a top performance threshold of $4.00 per common unit, representing a 33% increase over the November 2006 distribution level of $3.00 per unit. These grants are intended to encourage continued growth and fundamental performance that will support future distribution growth. These phantom units will vest in one-third increments as follows: one-third will vest upon the later of the May 2011 distribution date and the date on which we pay a quarterly distribution of at least $0.875; one-third will vest upon the later of the May 2011 distribution date and the date on which we pay a quarterly distribution of at least $1.00; and one-third will vest upon the later of the May 2012 distribution date and the date on which we pay a quarterly distribution of at least $0.9375. DERs associated with these units become payable in 25% increments upon achieving quarterly distribution levels of $0.85, $0.90, $0.95 and $1.00 per unit. Any phantom units that have not vested (and all associated DERs) as of the May 2014 distribution date will be forfeited. Upon vesting, the phantom units are payable on a one-for-one basis in common units (or cash equivalent). The 2007 awards included grants to our Named Executive Officers as follows: Mr. Armstrong, 180,000; Mr. Pefanis, 120,000; Mr. Kramer, 60,000; Mr. Duckett, 75,000, Mr. vonBerg, 54,000 and Mr. Coiner, 90,000 (as discussed below, Mr. Coiner s grants were cancelled in August 2007 in connection with his retirement). The number of phantom units awarded to our Named Executive Officers represents approximately 60% of the awards granted to such individuals in 2005.

During 2007, Class B units were issued to our Named Executive Officers as follows: Mr. Armstrong, 40,000; Mr. Pefanis, 30,000; Mr. Duckett, 17,000; and Mr. vonBerg, 14,000.

Other Compensation Related Matters

Equity Ownership in PAA. As of December 31, 2007, our current Named Executive Officers collectively owned substantial equity in the Partnership. Although we encourage our Named Executive Officers to retain ownership in the Partnership, we do not have a policy requiring maintenance of a specified equity ownership level. Our policies prohibit our Named Executive Officers from using puts, calls or options to hedge the economic risk of their ownership. In the aggregate, as of December 31, 2007, our current Named Executive Officers beneficially owned, in the aggregate, approximately 724,000 of our common units (excluding any unvested equity awards), an approximately 3% indirect ownership interest in our general partner and IDRs, and 101,000 Class B units of Plains AAP, L.P. Based on the market price of our common units at December 31, 2007 and an implied valuation for their collective general partner and IDR interests using similar valuation metrics, the value of the equity ownership of these individuals was significantly greater than the combined aggregate salaries and bonuses for 2007.

Recovery of Prior Awards. Except as provided by applicable laws and regulations, we do not have a policy with respect to adjustment or recovery of awards or payments if relevant company performance measures upon which previous awards were based are restated or otherwise adjusted in a manner that would reduce the size of such award or payment.

Section 162(m). With respect to the deduction limitations under Section 162(m) of the Code, we are a limited partnership and do not meet the definition of a corporation under Section 162(m).

Change in Control Triggers. The employment agreements for Messrs. Armstrong and Pefanis, the long-term incentive plan grants to our Named Executive Officers, and the Class B restricted units agreements include severance payment provisions or accelerated vesting triggered upon a change of control, as defined in the respective agreement. In the case of the long-term incentive plan grants, the provision becomes operative only if the change in control is accompanied by a change in status (such as the termination of employment by Plains All American GP LLC). We believe this double trigger arrangement is appropriate because it provides assurance to the executive, but does not offer a windfall to the executive when there has been no real change in employment status. The provisions in the employment agreements for Messrs. Armstrong and Pefanis become operative only if the executive terminates employment within three months of the change in control. Messrs. Armstrong and Pefanis agreed to a conditional waiver of these provisions with respect to a sale transaction in August 2005 that would have constituted a change in control. See Potential Payments upon Termination or Change-in-Control and Employment Agreements.

Former Named Executive Officer. As of August 31, 2007, Mr. Coiner retired as Senior Group Vice President. In connection with Mr. Coiner s retirement, we and Mr. Coiner entered into a separation agreement. Terms of the agreement provided for cancellation of substantially all outstanding equity awards (including awards for which performance thresholds had been achieved, but excluding from cancellation certain options granted in 2001 for which all performance and time vesting requirements have been satisfied) and payment to Mr. Coiner of a lump sum amount of approximately $8.7 million in satisfaction of our obligations with respect to the cancelled equity awards, deferred and quarterly bonus amounts for prior and current periods, accrued vacation and other related obligations. The agreement also includes (i) a provision pursuant to which Mr. Coiner will remain our consultant through the first quarter of 2009 and for such services will receive a quarterly fee of $500,000, (ii) a general release by Mr. Coiner of any claims against us and (iii) Mr. Coiner s agreement that his Confidential Information and Non-Solicitation Agreement dated November 23, 1998 will remain in full force and effect until March 31, 2010. In addition to the amounts noted above, we will pay the premiums for COBRA coverage for a period of up to 18 months.

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Summary Compensation Table

The following table sets forth certain compensation information for our Chief Executive Officer, Chief Financial Officer, the three other most highly compensated executive officers in 2007 and one former executive officer who retired during the fiscal year (our Named Executive Officers). We reimburse our general partner and its affiliates for expenses incurred on our behalf, including the costs of officer compensation (excluding the costs of the obligations represented by the Class B units).

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)(1)	All Other Compensation ($)(2)	Total ($)
Greg L. Armstrong	2007	375,000	3,400,000	5,660,135	14,430	9,449,565
Chairman and CEO	2006	375,000	3,750,000	5,184,222		