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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2005

OR

☐ **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 x No ☐

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

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

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

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

Large Accelerated Filer x   Accelerated Filer o   Non-Accelerated Filer o

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

The aggregate value of the Common Units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Common Units outstanding, for this purpose, as if they may be affiliates of the registrant) was approximately $2.3 billion on June 30, 2005, based on $43.86 per unit, the closing price of the Common Units as reported on the New York Stock Exchange on such date.

At February 17, 2006, there were outstanding 73,768,576 Common Units.

DOCUMENTS INCORPORATED BY REFERENCE
NONE

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FORM 10-K—2005 ANNUAL REPORT
Table of Contents

FORWARD-LOOKING STATEMENTS

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements identified by the words "anticipate," "believe," "estimate," "expect," "plan," "intend" and "forecast," and similar expressions and statements regarding our business strategy, plans and objectives of our management for future operations. However, the absence of these words 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:

- 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 system;
- declines in volumes shipped on the Basin Pipeline, Capline Pipeline and our other pipelines by us and third party shippers;
- the availability of adequate third party production volumes for transportation and marketing in the areas in which we operate;
- demand for natural gas or various grades of crude oil and resulting changes in pricing conditions or transmission throughput requirements;
- fluctuations in refinery capacity in areas supplied by our transmission lines;
- 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;
- 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 rates of 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;
- the impact of crude oil and natural gas price fluctuations;
- shortages or cost increases of power supplies, materials or labor;
- weather interference with business operations or project construction;
- general economic, market or business conditions; and
- other factors and uncertainties inherent in the marketing, transportation, terminalling, gathering and storage of crude oil and liquefied petroleum gas.

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 September 1998. Our operations are conducted directly and indirectly through our primary operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P. As used in this Form 10-K, the terms “we”, “us”, “our”, “ours” and similar terms refer to Plains All American Pipeline, L.P. and its subsidiaries, unless the context indicates otherwise. We are engaged in interstate and intrastate crude oil transportation and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of 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.”

We are one of the largest midstream crude oil companies in North America. We have an extensive network of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins, transportation corridors and at major market hubs in the United States and Canada. Our crude oil and LPG operations can be categorized into two primary business activities:

- *Crude Oil Pipeline Transportation Operations.* As of December 31, 2005, we owned approximately 15,000 miles (of which approximately 13,000 miles are included in our pipeline segment) of active gathering and mainline crude oil pipelines located throughout the United States and Canada. Our activities from pipeline operations generally consist of transporting volumes of crude oil for a fee and third party leases of pipeline capacity, barrel exchanges and buy/sell arrangements.

- *Gathering, Marketing, Terminalling and Storage Operations.* As of December 31, 2005, we owned approximately 39 million barrels of active above-ground crude oil terminalling and storage facilities, approximately 15 million barrels of which relate to our gathering, marketing, terminalling and storage segment (the remaining approximately 24 million barrels of tankage are associated with our pipeline transportation operations within our pipeline segment). These facilities include a crude oil terminalling and storage facility at Cushing, Oklahoma. Cushing, which we refer to as the Cushing Interchange, is one of the largest crude oil market hubs in the United States and is the designated delivery point for New York Mercantile Exchange, or NYMEX, crude oil futures contracts. We utilize our storage tanks to counter-cyclically balance our gathering and marketing operations and to execute various hedging strategies to stabilize profits and reduce the negative impact of crude oil market volatility, while at the same time providing upside exposure to opportunities inherent in volatile market conditions. Our terminalling and storage operations also generate revenue at the Cushing Interchange and our other locations through a combination of storage and throughput charges to third parties. We also own approximately 1.8 million barrels of LPG storage. Our gathering and marketing activities include:

  - 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 foreign cargoes at their load port and various other locations in transit;

  - the transportation of crude oil on trucks, barges, pipelines and ocean-going vessels;

  - the subsequent resale or exchange of crude oil at various points along the crude oil distribution chain; and

  - the purchase of LPG from producers, refiners and other marketers, the storage of LPG at storage facilities owned by us or third parties, the transportation of LPG to our terminals and the sale of LPG to wholesalers, retailers and industrial end users.

In addition, through our 50% equity ownership in PAA/Vulcan Gas Storage, LLC (“PAA/Vulcan”), we are engaged in the development and operation of natural gas storage facilities.

Business Strategy

Our principal business strategy is to provide competitive and efficient crude oil transportation, gathering, marketing, terminalling and storage services to our producer and refiner customers, and to address the regional crude oil supply and demand imbalances that exist in the United States and Canada by combining the strategic location and distinctive capabilities of our transportation and terminalling 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:

- increasing and optimizing throughput on our existing pipeline and gathering assets and realizing cost efficiencies through operational improvements;

- utilizing our Gulf Coast assets, our Cushing Terminal and leased assets to increase our presence in the importation of foreign crude oil through Gulf of Mexico receipt facilities;

- developing and implementing internal growth projects that address evolving needs in the crude oil transportation sector and that are well positioned to benefit from long-term industry trends and opportunities;

- selectively pursuing strategic and accretive acquisitions of crude oil marketing, transportation, gathering, terminalling and storage assets that complement our existing asset base and distribution capabilities; and

- using our terminalling and storage assets in conjunction with merchant and hedging activities to address physical market imbalances, mitigate inherent risks and increase margin.

To a lesser degree, we engage in a similar business strategy with respect to the wholesale marketing and storage of LPG and, through our 50% ownership in PAA/Vulcan, in the storage of natural gas. 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 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 have consistently communicated to the financial community our intention to maintain a strong credit profile that we believe is consistent with an investment grade credit rating. We have targeted a general credit profile with the following attributes:

- an average long-term debt-to-total capitalization ratio of approximately 50%;

- an average long-term debt-to-EBITDA ratio of approximately 3.5x or less (EBITDA is earnings before interest, taxes, depreciation and amortization); and

- an average EBITDA-to-interest coverage ratio of approximately 3.3x or better.

Based on our financial position at December 31, 2005 and operating and financial results for 2005, we were within our targeted credit profile. 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 may initially be financed using debt.

Credit Rating

As of February 2006, our senior unsecured ratings with Standard & Poor’s and Moody’s Investment Services were BBB- stable and Baa3 stable, respectively, both of which are considered “investment grade.’’ We have targeted the attainment of even stronger investment grade ratings of BBB+ and Baa1 for Standard & Poor’s and Moody’s Investment Services, respectively. We cannot give assurance that our current ratings will remain in effect for any given period of time, that we will be able to attain the higher ratings we have targeted or that one or both of these ratings will not be lowered or withdrawn entirely by the ratings agency. Note that a credit rating is not a recommendation to buy, sell or hold securities, and may be revised or withdrawn at any time.

Competitive Strengths

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

- ***Many of our pipeline transportation and storage assets are strategically located and operationally flexible and have additional capacity or expansion capability.*** Our primary crude oil pipeline transportation and gathering assets are located in well-established oil producing regions and transportation corridors and are connected, directly or indirectly, with our terminalling and storage assets that are 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. Specific assets with additional capacity or expansion potential include our ownership interest in the Capline System, our Cushing Terminal and our St. James Terminal, which is expected to be in service in 2007. Our Cushing Terminal is a designated delivery point for the NYMEX crude oil futures contract and is one of the most modern large-scale terminalling and storage facilities at the Cushing Interchange, incorporating operational enhancements designed to safely and efficiently terminal, store, blend and segregate large volumes and multiple varieties of crude oil. When completed, our St. James Terminal will have many similar characteristics.
- ***We possess specialized crude oil market knowledge.*** We believe our business relationships with participants in various phases of the crude oil distribution chain, from crude oil producers to refiners, as well as our own industry expertise, provide us with an extensive understanding of the North American physical crude oil markets.
- ***Our business activities are counter-cyclically balanced.*** We believe that our terminalling and storage activities and our gathering and marketing activities are counter-cyclical. We believe that this balance of activities, combined with our pipeline transportation operations, generally provides us with the flexibility to maintain a base level of margin irrespective of whether a strong or weak market exists and, 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 eight years, we have completed and integrated approximately 35 acquisitions with an aggregate purchase price of approximately $2.0 billion. We have also implemented internal expansion capital projects totaling over $400 million. In addition, we believe we have significant resources to finance future strategic expansion and acquisition opportunities. As of December 31, 2005, we had approximately $789 million available under our committed credit facilities, subject to covenant compliance. We believe we have one of the strongest capital structures relative to other master limited partnerships with

capitalizations greater than $1.0 billion. In addition, the investors in our general partner are diverse and financially strong and have demonstrated their support by providing capital to help finance previous acquisitions. We believe they are supportive long-term sponsors of the partnership.

- ***We have an experienced management team whose interests are aligned with those of our unitholders.*** Our executive management team has an average of more than 20 years industry experience, with an average of more than 15 years with us or our predecessors and affiliates. Members of our senior management team own an approximate 5% interest in our general partner and collectively own approximately 900,000 common units, including fully vested options. In addition, through grants of phantom units, the senior management team also owns significant contingent equity incentives that generally vest upon achievement of performance objectives, continued service or both.

We believe many of these competitive strengths have similar application to our efforts to expand our presence in the natural gas storage sector. See “—Natural Gas Storage Market Overview” and
“—Description of PAA/Vulcan Natural Gas Storage Assets.”

Organizational History

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

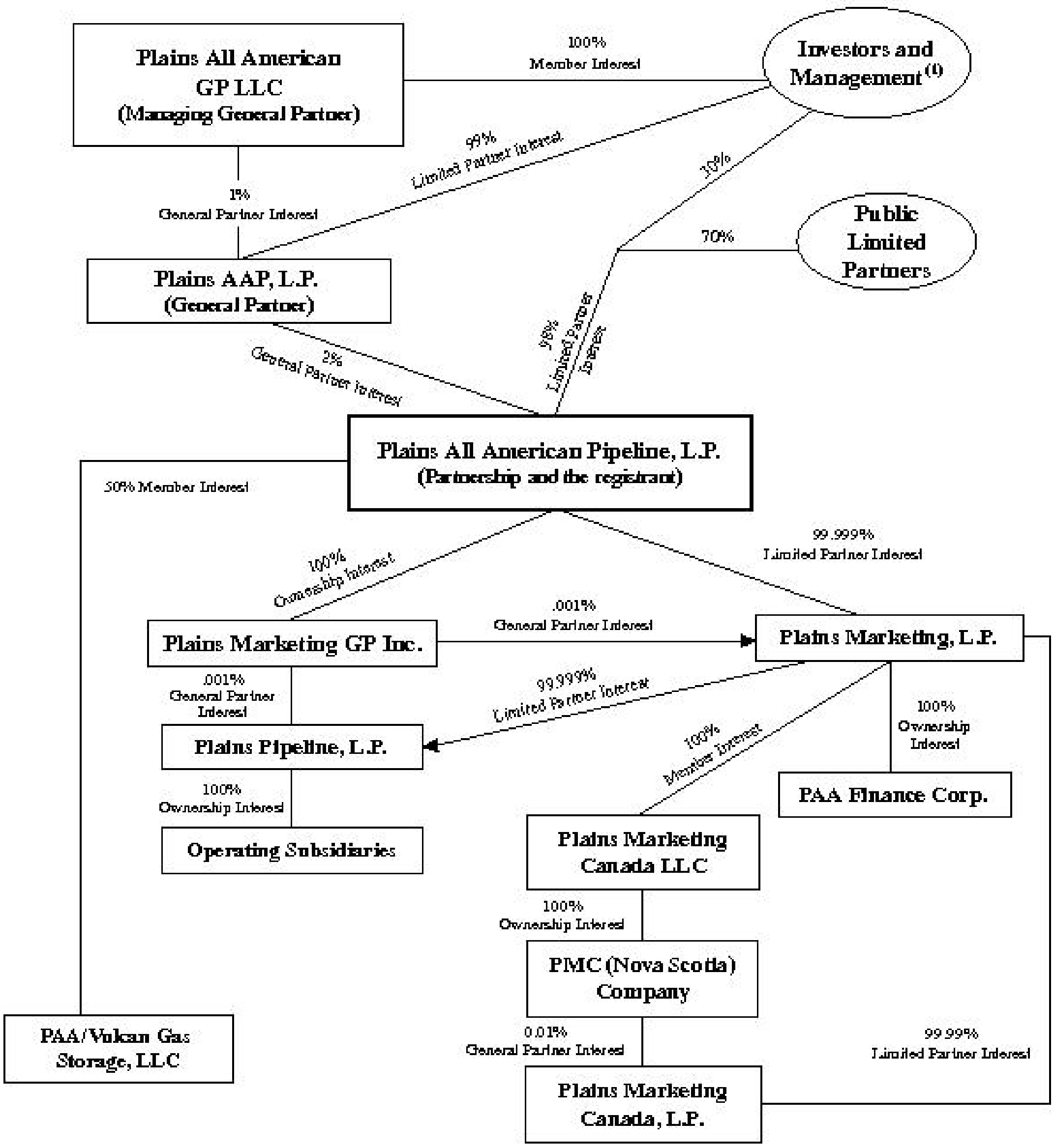
Partnership Structure and Management

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. We own our interests in our subsidiaries through two operating partnerships, Plains Marketing, L.P. and Plains Pipeline, L.P. Our Canadian and LPG operations are conducted through Plains Marketing Canada, L.P.

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

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

Partnership Structure



(1) Based on Form 4 filings for 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, beneficially owns approximately 21.6 million limited partner units, representing approximately 30% of all outstanding units.

Acquisitions

The acquisition of assets and operations that are strategic and complementary to our existing operations constitutes an integral component of our business strategy and growth objective. Such assets and operations include crude oil related assets and LPG assets, as well as 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. 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. Since 1998, and through December 31, 2005, we have completed numerous acquisitions for a cumulative purchase price of approximately $2.0 billion. In addition, from time to time, we have sold assets that are no longer considered essential to our operations.

The following table summarizes selected acquisitions that we have completed over the past five years:

Acquisition	Date	Description	Approximate Purchase Price (in millions)

Investment in Natural Gas Storage Facilities	September 2005	Joint venture with Vulcan Gas Storage LLC to develop and operate natural gas storage facilities.	$ 125[(1)]
Schaefferstown Propane Storage Facility	August 2004	Storage capacity of approximately 0.5 million barrels of refrigerated propane	$ 32
Cal Ven Pipeline System	May 2004	195 miles of gathering and mainline crude oil pipelines in northern Alberta	$ 19
Link Energy LLC	April 2004	The North American crude oil and pipeline operations of Link Energy, LLC ("Link")	$ 332
Capline and Capwood Pipeline Systems	March 2004	An approximate 22% undivided joint interest in the Capline Pipeline System and an approximate 76% undivided joint interest in the Capwood Pipeline System	$ 158
South Saskatchewan Pipeline System	November 2003	A 158-mile mainline crude oil pipeline and 203 miles of gathering lines in Saskatchewan	$ 48
ArkLaTex Pipeline System	October 2003	240 miles of crude oil gathering and mainline pipelines and 470,000 barrels of crude oil storage capacity	$ 21
Iraan to Midland Pipeline System	June 2003	98-mile mainline crude oil pipeline	$ 18
South Louisiana Assets	June 2003 and December 2003	Various terminalling and gathering assets in South Louisiana, including a 100% interest in Atchafalaya Pipeline, L.L.C.	$ 18
Iatan Gathering System	March 2003	West Texas crude oil gathering system	$ 24
Red River Pipeline System	February 2003	334-mile crude oil pipeline along with 645,000 barrels of crude oil storage capacity	$ 19

Shell West Texas Assets	August 2002	Basin Pipeline System, Permian Basin Pipeline System and the Rancho Pipeline System	$ 324
Canadian Operations	May/July 2001	The assets of CANPET Energy Group (crude oil and LPG marketing) and substantially all of the Canadian crude oil pipeline, gathering, storage and terminalling assets of Murphy Oil Company Ltd. (560 miles of crude oil and condensate mainlines along with 1.1 million barrels of crude oil storage and terminalling capacity)	$ 232

(1) Represents 50% of the purchase price for the acquisition made by our joint venture. The joint venture completed an acquisition for approximately $250 million during 2005. See "—Investment in Natural Gas Storage Facilities" below.

Ongoing Acquisition Activities

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

Investment in Natural Gas Storage Facilities

PAA/Vulcan, a limited liability company, was formed in the third quarter of 2005. We own 50% of PAA/Vulcan and the remaining 50% is owned by Vulcan Gas Storage LLC, a subsidiary of Vulcan Capital, the investment arm of Paul G. Allen. The Board of Directors of PAA/Vulcan consists of an equal number of our representatives and representatives of Vulcan Gas Storage, and is responsible for providing strategic direction and policy-making. We, as the managing member, are responsible for the day-to-day operations. PAA/Vulcan is not a variable interest entity, and we do not have the ability to control the entity; therefore, we account for the investment under the equity method in accordance with Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." This investment is reflected on a separate line in our consolidated balance sheet.

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 and Vulcan Gas Storage LLC each made an initial cash investment of approximately $112.5 million, and a subsidiary of PAA/Vulcan entered into a $90 million credit facility contemporaneously with closing. Approximately $255 million of the total funding of $315 million was used to finance the acquisition and closing costs. It is anticipated that the remaining balance will be combined with funds obtained from future financing activities related to the construction of an underground natural gas storage facility in South Louisiana.

Crude Oil Market Overview

Our assets and our business strategy are designed to service our producer and refiner customers by addressing regional crude oil supply and demand imbalances that exist in the United States and Canada. According to the Energy Information Administration ("EIA"), the United States consumes approximately 15.3 million barrels of crude oil per day, while only producing 5.2 million barrels per day. Accordingly, the United States relies on foreign imports for nearly 66% of the crude oil used by U.S. domestic refineries. This imbalance represents a continuing trend. Foreign imports of crude oil into the U.S. have tripled over the last 21 years, increasing from 3.2 million barrels per day in 1984 to 10.1 million barrels per day for the 12 months ended November 2005, as U.S. refinery demand has increased and domestic crude oil production has declined due to natural depletion.

The Department of Energy segregates the United States into five Petroleum Administration Defense Districts ("PADDs") which are used by the energy industry for reporting statistics regarding crude oil supply and demand. The table below sets forth supply, demand and shortfall information for each PADD for the twelve months ended November 2005 and is derived from information published by the EIA (see EIA website at www.eia.doe.gov).

Petroleum Administration Defense District	Regional Supply	Refinery Demand	Supply Shortfall
	(Millions of barrels per day)		
PADD I (East Coast)	0.0	1.6	(1.6)
PADD II (Midwest)	0.5	3.3	(2.8)
PADD III (South)	2.8	7.1	(4.3)
PADD IV (Rockies)	0.3	0.6	(0.3)
PADD V (West Coast)	1.6	2.7	(1.1)
Total U.S.	**5.2**	**15.3**	**(10.1)**

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

Over the last 21 years, crude oil production in PADD II has declined from approximately 1.0 million barrels per day to approximately 500,000 barrels per day. Over this same time period, refinery demand has increased from approximately 2.7 million barrels per day in 1984 to 3.3 million barrels per day for the twelve months ended November 2005. As a result, the volume of crude oil transported into PADD II has increased 65%, from 1.7 million barrels per day to 2.8 million barrels per day. This aggregate shortfall is principally supplied from the north by direct imports from Canada and from the Gulf Coast area and the Cushing Interchange to the south.

The logistical transportation, terminalling and storage challenges associated with regional volumetric supply and demand imbalances are further complicated by the fact that crude oil from different sources is not fungible. The crude slate available to U.S. refineries consists of over 50 different grades and varieties of crude oil. Each crude grade has distinguishing physical properties, such as specific gravity (generally referred to as light or heavy), sulfur content (generally referred to as sweet or sour) and metals content as well as varying economic attributes. In many cases, these factors result in the need for such grades to be batched or segregated in the transportation and storage processes, blended to precise specifications or adjusted in value. In addition, from time to time, natural disasters and geopolitical factors, such as hurricanes, earthquakes, tsunamis, inclement weather, labor strikes, refinery disruptions, embargoes and armed conflicts, may impact supply, demand and transportation and storage logistics.

Description of Segments and Associated Assets

Our crude oil and LPG business activities are conducted through two primary segments, Pipeline Operations and Gathering, Marketing, Terminalling and Storage Operations ("GMT&S"). We have an extensive network of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins, transportation corridors and at major market hubs in the United States and Canada.

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

Pipeline Operations

As of December 31, 2005, we owned approximately 15,000 miles of active gathering and mainline crude oil pipelines located throughout the United States and Canada. Approximately 13,000 miles of these pipelines are used in our pipeline operations segment with the remainder used in our GMT&S segment. Our activities from pipeline operations generally consist of transporting crude oil for a fee and third party leases of pipeline capacity, as well as barrel exchanges and buy/sell arrangements.

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

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

Major Pipeline Assets

All American Pipeline System

The All American Pipeline is a common carrier crude oil pipeline system that transports crude oil produced from certain outer continental shelf, or OCS, fields offshore California via connecting pipelines to refinery markets in California. The system extends approximately 10 miles along the California coast from Las Flores to Gaviota (24-inch diameter pipe) and continues from Gaviota approximately 126 miles to our station in Emidio, California (30-inch diameter pipe). Between Gaviota and our Emidio Station, the All American Pipeline interconnects with our San Joaquin Valley, or SJV, Gathering System as well as various third party intrastate pipelines. The system is subject to tariff rates regulated by the Federal Energy Regulatory Commission ("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 ("PXP") 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, which expire in August 2007, 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 2005 and 2004, the tariffs averaged $1.87 per barrel and $1.81 per barrel, respectively. Effective January 1, 2006, based on the contractual escalator, the average tariff increased to $2.04 per barrel. The agreements do not require these owners to transport a minimum volume.

Approximately 10% of our revenues less purchases and field operating costs are derived from the pipeline transportation business associated with these two fields. The relative contribution to our revenues less direct field operating costs from these fields has decreased from approximately 26% in 2001 to current levels because of both (i) declines in volumes produced and transported from these fields and (ii) increases in our revenues from acquisitions and internal expansion projects. Since our acquisition of the system in 1998, the volume decline has been substantially offset by an increase in pipeline tariffs. Over the last ten years, transportation volumes received from the Santa Ynez and Point Arguello fields have declined from 92,000 and 60,000 average daily barrels, respectively, in 1995 to 41,000 and 10,000 average daily barrels, respectively, for 2005. We expect that there will continue to be natural production declines from each of these fields as the underlying reservoirs are depleted. A 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual pipeline segment profit of approximately $3.5 million, based on a tariff of $2.04 per barrel.

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

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(barrels in thousands)				
Average daily volumes received from:					
Point Arguello (at Gaviota)	10	10	13	16	18
Santa Ynez (at Las Flores)	41	44	46	50	51
Total	51	54	59	66	69

Basin Pipeline System

The Basin Pipeline System, in which we own an approximate 87% undivided joint interest, is a primary route for transporting Permian Basin crude oil to Cushing, Oklahoma, for further delivery to Mid-Continent and Midwest refining centers. We acquired our interest in the Basin Pipeline System in August 2002. Since acquisition, we have been the operator of the system. The Basin system is a 515-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 290,000 barrels per day (net to our interest) during 2005. Within the current operating range, a 20,000 barrel per day decline in volumes shipped on the Basin system would result in a decrease in annual pipeline segment profit of approximately $1.4 million.

The Basin system consists of three primary movements of crude oil: (i) barrels that are shipped from Jal, New Mexico to the West Texas markets of Wink and Midland, where they are exchanged and/or further shipped to refining centers; (ii) barrels that are shipped to the Mid-Continent region on the Midland to Wichita Falls segment and the Wichita Falls to Cushing segment; and (iii) foreign and Gulf of Mexico barrels that are delivered into Basin at Wichita Falls and delivered to a connecting carrier or shipped to Cushing for further distribution to Mid-Continent or Midwest refineries. The system also

includes approximately 5.5 million barrels (4.8 million barrels, net to our interest) of crude oil storage capacity located along the system.

In 2004, we expanded an approximate 425-mile section of the system from Midland to Cushing. With the completion of this expansion, the capacity of this section has increased approximately 15%, from 350,000 barrels per day to approximately 400,000 barrels per day. The Basin system is subject to tariff rates regulated by the FERC.

Capline/Capwood Pipeline Systems

The Capline Pipeline System, in which we own a 22% undivided joint interest, is a 633-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capline Pipeline System is one of the primary transportation routes for crude oil shipped into the Midwestern U.S., accessing over 2.7 million barrels of refining capacity in PADD II. Shell is the operator of this system. Capline has direct connections to a significant amount of crude production in the Gulf of Mexico. In addition, with its two active docks capable of handling 600,000-barrel tankers as well as access to the Louisiana Offshore Oil Port ("LOOP"), it is a key transporter of sweet and light sour foreign crude to PADD II. With a total system operating capacity of 1.14 million barrels per day of crude oil, approximately 248,000 barrels per day are subject to our interest. During 2005, throughput on our interest has averaged approximately 132,000 barrels per day. A 10,000 barrel per day decline in volumes shipped on the Capline system would result in a decrease in our annual pipeline segment profit of approximately $1.3 million.

The Capwood Pipeline System, in which we own a 76% undivided joint interest, is a 58-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois. The Capwood Pipeline System has an operating capacity of 277,000 barrels per day of crude oil. Of that capacity, approximately 211,000 barrels per day are subject to our interest. The system has the ability to deliver crude oil at Wood River to several other PADD II refineries and pipelines. Movements on the Capwood system are driven by the volumes shipped on Capline as well as by volumes of Canadian crude that can be delivered to Patoka via the Mustang Pipeline. PAA assumed the operatorship of the Capwood system from Shell Pipeline Company LP at the time of purchase. During 2005 throughput net to our interest averaged approximately 107,000 barrels per day.

Our significant pipeline systems are discussed on the previous pages. Following is a tabular presentation of all of our active pipeline assets in the United States and Canada, including those previously mentioned, grouped by geographic location:

Region	Pipeline	Ownership Percentage	Pipeline Mileage	2005 Average Net Barrels per day[1]
Southwest US	Basin	87.0%	515	290,000
	West Texas Gathering	100.0%	800	81,000
	Permian Basin Gathering	100.0%	819	56,000
	Dollarhide	100.0%	24	5,000
	Mesa	53.5%	79	32,000
	Iraan	100.0%	98	30,000
	Iatan	100.0%	360	21,000
	New Mexico	100.0%	1,185	77,000
	Texas	100.0%	1,276	93,000
	Lefors	100.0%	68	2,000
	Merkel	100.0%	128	3,000
	Hardemann	100.0%	65	5,000
	Garden City	100.0%	5	7,000
	Spraberry Gathering	100.0%	412	33,000
Western US	All American	100.0%	140	51,000
	San Joaquin Valley	100.0%	77	74,000
US Rocky Mountains	Butte	22.0%	370	17,000
	North Dakota	100.0%	620	77,000
US Gulf Coast	Sabine Pass	100.0%	33	11,000
	Ferriday	100.0%	290	8,000
	La Gloria	100.0%	119	24,000
	Red River	100.0%	359	17,000
	ArkLaTex	100.0%	107	15,000
	Red Rock	100.0%	55	3,000
	Atchafalaya	100.0%	35	13,000
	Eugene Island	100.0%	66	10,000
	Bridger Lakes	100.0%	17	2,000
	Capline	22.0%	633	132,000
	Capwood/Patoka	76.0%	58	116,000
	Pearsall	100.0%	62	2,000
	Mississippi/Alabama	100.0%	601	57,000
	Southwest Louisiana	100.0%	217	4,000
	Cocodrie	100.0%	27	6,000
	Golden Meadows	100.0%	33	4,000
	Turtle Bayou	100.0%	14	5,000
	Erath	100.0%	50	6,000
	Hiedelberg	100.0%	72	13,000
	East Texas	100.0%	19	7,000
Central US	Oklahoma	100.0%	1,498	62,000
	Midcontinent	100.0%	1,197	29,000
	Cushing to Broome	100.0%	100	66,000
	United States Total		12,703	1,566,000
Canada	Cal Ven	100.0%	92	16,000
	Manito	100.0%	101	63,000
	Milk River	100.0%	19	102,000
	Cactus Lake	14.9%	82	3,000
	Wascana	100.0%	107	4,000
	Wapella	100.0%	73	16,000
	Joarcam	100.0%	35	3,000
	South Sask	100.0%	158	48,000
	Canada Total		667	255,000
	Total		13,370	1,821,000

(1) Reflects volumes for the entire year for all pipeline systems including those reclassified to the pipeline segment during 2005.

Gathering, Marketing, Terminalling and Storage Operations

The combination of our gathering and marketing operations and our terminalling and storage operations provides a counter-cyclical balance that has a stabilizing effect on our operations and cash flow. The strategic use of our terminalling and storage assets in conjunction with our gathering and marketing operations generally provides us with the flexibility to maintain a base level of margin irrespective of whether a strong or weak market exists and, in certain circumstances, to realize incremental margin during volatile market conditions. Following is a description of our activities with respect to this segment.

Gathering and Marketing Operations

Crude Oil. The majority of our gathering and marketing activities are in the geographic locations previously discussed. These activities include:

- purchasing crude oil from producers at the wellhead and in bulk from aggregators at major pipeline interconnects or trading locations, as well as foreign cargoes at their load port and various other locations in transit;
- transporting crude oil on our own proprietary gathering assets and our common carrier pipelines or, when necessary or cost effective, assets owned and operated by third parties, including pipelines, trucks, barges and ocean-going vessels;
- exchanging crude oil for another grade of crude oil or at a different geographic location, as appropriate, in order to maximize margins or meet contract delivery requirements; and
- marketing crude oil to refiners or other resellers.

We purchase crude oil from multiple producers and believe that we generally have established broad-based relationships with the crude oil producers in our areas of operations. Gathering and marketing activities involve relatively large volumes of transactions, often with lower margins than pipeline and terminalling and storage operations.

The following table shows the average daily volume of our lease gathering and bulk purchases for the past five years:

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(barrels in thousands)				
Lease gathering	610	589	437	410	348
Bulk purchases (domestic and foreign)	219	161	90	68	46
Total volumes per day	829	750	527	478	394

Crude Oil 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. In a typical producer's operation, crude oil flows from the wellhead to a separator where the petroleum gases are removed. After separation, the crude oil is treated to remove water, sand and other contaminants and is then moved into the producer's on-site storage tanks. When the tank is approaching capacity, the producer contacts our field personnel to purchase and transport the crude oil to market. We utilize our truck fleet and gathering pipelines as well as third party pipelines, trucks, barges and ocean-going vessels to transport the crude oil to market. We own or lease approximately 500 trucks used for gathering crude oil. 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.

Bulk Purchases. 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 purchase crude oil in

bulk when we believe additional opportunities exist to realize margins further downstream in the crude oil distribution chain. The opportunities to earn additional margins vary over time with changing market conditions.

Crude Oil Sales. The marketing of crude oil is complex and requires current detailed knowledge of crude oil 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 for the different grades of crude oil, location of customers, availability of transportation facilities and timing and costs (including storage) involved in delivering crude oil 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 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 with respect to futures contracts on the NYMEX, International Petroleum Exchange ("IPE") or over-the-counter. Through these transactions, we seek to maintain a position that is substantially balanced between crude oil 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 futures contracts as hedging devices. Except for pre-defined inventory positions, our policy is generally to purchase only crude oil for which we have a market, to structure our sales contracts so that crude oil price fluctuations do not materially affect the segment profit we receive, and to not acquire and hold crude oil, futures contracts or other derivative products for the purpose of speculating on crude oil price changes as these activities could expose us to significant losses.

Crude Oil 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 of crude oil that more closely matches our physical delivery requirement or the preferences of our refinery customers, we exchange physical crude oil 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 that differs in terms of geographic location, grade of crude oil or physical delivery schedule from crude oil we have available for sale. Generally, we enter into exchanges to acquire crude oil 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. The accounting for buy/sell agreements is expected to change in 2006. See Note 2 to our Consolidated Financial Statements.

Producer Services. Crude oil purchasers who buy from producers compete on the basis of competitive prices and highly responsive services. Through our team of crude oil purchasing representatives, we maintain ongoing relationships with producers in the United States and Canada. We believe that our ability to offer high-quality field and administrative services to producers is a key factor in our ability to maintain volumes of purchased crude oil and to obtain new volumes. Field services include efficient gathering capabilities, availability of trucks, willingness to construct gathering pipelines where economically justified, timely pickup of crude oil from tank batteries at the lease or production point, accurate measurement of crude oil volumes received, and effective management of pipeline deliveries. Accounting and other administrative services include securing division orders (statements from interest owners affirming the division of ownership in crude oil purchased by us), providing statements of the crude oil purchased each month, disbursing production proceeds to interest owners, and calculating and paying ad valorem and production taxes on behalf of interest owners. In order to compete effectively, we must maintain records of title and division order interests in an accurate and timely manner for purposes of making prompt and correct payment of crude oil production proceeds, together with the correct payment of all severance and production taxes associated with such proceeds.

Liquefied Petroleum Gas and Other Petroleum Products. We also market and store LPG and other petroleum products in the United States and Canada. These activities include:

- purchasing LPG (primarily propane and butane) from producers at gas plants and in bulk at major pipeline terminal points and storage locations;
- transporting the LPG via common carrier pipelines, railcars and trucks to our own terminals and third party facilities for subsequent resale to retailers and other wholesale customers; and
- exchanging product to other locations to maximize margins and /or to meet contract delivery requirements.

We purchase LPG from numerous producers and have established long-term, broad based relationships with LPG producers in our areas of operation. We purchase LPG directly from gas plants, major pipeline terminals, refineries and storage locations. Marketing activities for LPG typically consist of smaller volumes per transaction relative to crude oil.

LPG Purchases. We purchase LPG from producers, refiners, and other LPG marketing companies under contracts that range from immediate delivery to one year in term. In a typical producer's or refiner's operation, LPG that is produced at the gas plant or refinery is fractionated into various components including propane and butane and then purchased by us for movement via tank truck, railcar or pipeline.

In addition to purchasing LPG at gas plants or refineries, we also purchase LPG in bulk at major pipeline terminal points and storage facilities from major oil companies, large independent producers or other LPG marketing companies. We purchase LPG in bulk when we believe additional opportunities exist to realize margins further downstream in our 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.

LPG Sales. The marketing of LPG is complex and requires current detailed knowledge of LPG sources and end markets and a familiarity with a number of factors including the various modes and availability of transportation, area market prices and timing and costs of delivering LPG to customers.

We sell LPG primarily to industrial end users and retailers, and limited volumes to other marketers. Propane is sold to small independent retailers who then transport the product via bobtail truck to residential consumers for home heating and to some light industrial users such as forklift operators. Butane is used by refiners for gasoline blending and as a diluent for the movement of conventional heavy oil production. Butane demand for use as a heavy oil diluent has increased as indigenous supplies of Canadian condensate have declined.

We establish a margin for propane by transporting it in bulk, via various transportation modes, to terminals where we deliver the propane to our retailer customers for subsequent delivery to their individual heating customers. We also create margin by selling propane for future physical delivery to third party users, such as retailers and industrial users. Through these transactions, we seek to maintain a position that is substantially balanced between propane purchases and sales and future delivery obligations. From time to time, we enter into various types of sale and exchange transactions including floating price collar arrangements, financial swaps and crude oil and LPG-related futures contracts as hedging devices. Except for pre-defined inventory positions, our policy is generally to purchase only LPG for which we have a market, and to structure our sales contracts so that LPG spot price fluctuations do not materially affect the segment profit we receive. Margin is created on the butane purchased by delivering large volumes during the short refinery blending season through the use of our extensive leased railcar fleet and the use of our own storage facilities and third party storage facilities. We also create margin on

butane by capturing the difference in price between condensate and butane when butane is used to replace condensate as a diluent for the movement of Canadian heavy oil production. Although we seek to maintain a position that is substantially balanced within our LPG activities, as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions, from time to time we experience net unbalanced positions for short periods of time. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, our policies provide that any net imbalance may not exceed 250,000 barrels. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations.

LPG Exchanges. We pursue exchange opportunities to enhance margins throughout the marketing process. When opportunities arise to increase our margin or to acquire a volume of LPG that more closely matches our physical delivery requirement or the preferences of our customers, we exchange physical LPG with third parties. These exchanges are effected through contracts called exchange or buy/sell agreements. Through an exchange agreement, we agree to buy LPG that differs in terms of geographic location, type of LPG or physical delivery schedule from LPG we have available for sale. Generally, we enter into exchanges to acquire LPG at locations that are closer to our end markets in order to meet the delivery specifications of our physical delivery contracts.

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

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

Because our typical crude oil sales transactions can involve tens of thousands of barrels of crude oil, the risk of nonpayment and nonperformance by customers is a major consideration in our business. We believe our sales are made to creditworthy entities or entities with adequate credit support. Generally, sales of crude oil are settled within 30 days of the month of delivery (in the case of foreign cargoes, typically 10 days after delivery), and pipeline, transportation and terminalling services also settle within 30 days from invoice for the provision of services.

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

Terminalling and Storage Operations

We own approximately 39 million barrels of active above-ground crude oil terminalling and storage assets. Approximately 15 million barrels of capacity are used in our GMT&S segment, and the remaining 24 million barrels are used in our Pipeline segment. Our storage and terminalling operations increase our margins in our business of purchasing and selling crude oil and also generate revenue through a combination of storage and throughput charges to third parties. Storage fees are generated when we lease tank capacity to third parties. Terminalling fees, also referred to as throughput fees, are generated when we receive crude oil from one connecting pipeline and redeliver crude oil to another connecting carrier in

volumes that allow the refinery to receive its crude oil on a ratable basis throughout a delivery period. Both terminalling and storage fees are generally earned from:

- refiners and gatherers that segregate or custom blend crudes for refining feedstocks; and
- pipeline operators, refiners or traders that need segregated tankage for foreign cargoes.

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).

Our most significant terminalling and storage asset is our Cushing Terminal located at the Cushing Interchange. The Cushing Interchange is 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 Cushing Terminal is also used to support and enhance the margins associated with our merchant activities relating to our lease gathering and bulk purchasing activities. See "—Gathering, Marketing, Terminalling and Storage Operations—Gathering and Marketing Operations—Bulk Purchases." Since 1999, we have completed five separate expansion phases, which increased the capacity of the Cushing Terminal to a total of approximately 7.4 million barrels. The Cushing Terminal now consists of fourteen 100,000-barrel tanks, four 150,000-barrel tanks and twenty 270,000-barrel tanks, all of which are used to store and terminal crude oil. The Cushing Terminal also includes a pipeline manifold and pumping system that has an estimated throughput capacity of over 1.0 million barrels per day. The Cushing Terminal is connected to the major pipelines and other terminals in the Cushing Interchange through pipelines that range in size from 10 inches to 24 inches in diameter.

The Cushing Terminal is designed to serve the needs of refiners in the Midwest (PADD II). In order to service an increase in volumes and varieties of foreign and domestic crude oil projected to be transported through the Cushing Interchange, we incorporated certain attributes into the original design of the Cushing Terminal including:

- multiple, smaller tanks to facilitate simultaneous handling of multiple crude varieties in accordance with normal pipeline batch sizes;
- dual header systems connecting most tanks to the main manifold system to facilitate efficient switching between crude grades with minimal contamination;
- bottom drawn sumps that enable each tank to be efficiently drained down to minimal remaining volumes to minimize crude oil contamination and maintain crude oil integrity during changes of service;
- mixer(s) on each tank to facilitate blending crude oil grades to refinery specifications; and
- a manifold and pump system that allows for receipts and deliveries with connecting carriers at their maximum operating capacity.

As a result of incorporating these attributes into the design of the Cushing Terminal, we believe we are favorably positioned to serve the needs of Midwest (PADD II) refiners to handle an increase in the number of varieties of crude oil transported through the Cushing Interchange. The pipeline manifold and

pumping system of our Cushing Terminal is designed to support more than 10 million barrels of tank capacity. Our tankage in Cushing ranges in age from less than a year old to approximately 12 years old and the average age is approximately 5 years old. In contrast, we estimate that the average age of the remaining tanks in Cushing owned by third parties is in excess of 40 years. We believe that provides us with a long-term competitive advantage.

Our Cushing Terminal also incorporates numerous environmental and operational safeguards that distinguish it from all other facilities at the Cushing Interchange. Each tank is equipped with both primary and secondary floating roof seals, a secondary liner (the equivalent of a double bottom) with leak detection devices, dual zone overfill protection alarms and a foam dispersal system that, in the event of a fire, is fed by a fully automated fire water distribution system. Additionally, almost all terminal piping is aboveground for monitoring and inspection purposes and the facility is fully automated with real-time computer monitoring of operational data.

We also have a marine terminal in Mobile, Alabama (the "Mobile Terminal") that consists of eighteen tanks ranging in size from 10,000 barrels to 225,000 barrels, with current useable capacity of 1.5 million barrels. Approximately 1.8 million barrels of additional storage capacity is available at our nearby Ten Mile Facility through a 36" pipeline connecting the two facilities. The Mobile Terminal is equipped with a ship/tanker dock, barge dock, truck-unloading facilities and various third party connections for crude 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.

In 2005, we began construction of a 3.2 million barrel crude oil terminal at the St. James crude oil interchange in Louisiana, which is one of the three most liquid crude oil interchanges in the United States. We plan to build seven tanks ranging from 190,000 barrels to 625,000 barrels at the St. James Terminal, which is expected to be operational in mid-2007. The facility will also include a manifold and header system that will allow for receipts and deliveries with connecting pipelines at their maximum operating capacity.

We also own LPG storage facilities located in Alto, Michigan; Schaefferstown, Pennsylvania; Tulsa, Oklahoma and Claremont, New Hampshire. The Alto facility is approximately 20 miles southeast of Grand Rapids. The Alto facility is capable of storing over 1.2 million barrels of LPG. The Schaefferstown facility is approximately 65 miles northwest of Philadelphia and is capable of storing over 0.5 million barrels of propane. The Tulsa facility consists of a 130-mile pipeline originating in Medford, Oklahoma. The Tulsa Terminal is capable of storing 19,000 barrels of propane and has two truck loading stations. The Claremont facility is on the Vermont border and has the capacity to store approximately 17,000 barrels of propane. In addition, the Claremont facility has three truck loading stations and four rail unloading stations. We believe these facilities will further support the expansion of our LPG business in Canada and the northern tier of the U.S. as we combine the facilities' existing fee-based storage business with our wholesale propane marketing expertise. In addition, there may be opportunities to expand these facilities as LPG markets continue to develop in the region.

Crude Oil Volatility; Counter Cyclical Balance; Risk Management

Crude oil prices have historically been very volatile and cyclical, with NYMEX benchmark prices ranging from a high of almost $71 per barrel (August 2005) to as low as $10 per barrel (March 1986) over the last 20 years. Segment profit from terminalling and storage activities is dependent on the crude oil 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 gathering and marketing activities is dependent on our ability to sell crude oil at a price in excess of our aggregate cost. Although margins may be affected during transitional periods, these 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, 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 marketing margins, but is favorable to the storage business, because storage owners at major trading locations (such as the Cushing Interchange) can simultaneously purchase production at current prices for storage and sell at higher prices for future delivery.

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

The periods between a backwardated market and a contango market are referred to as transition periods. Depending on the overall duration of these transition periods, how we have allocated our assets to particular strategies and the time length of our crude oil purchase and sale contracts and storage lease agreements, these transition periods may have either an adverse or beneficial affect on our aggregate segment profit. A prolonged transition from a backwardated market to a contango market, or vice versa (essentially a market that is neither in pronounced backwardation nor contango), represents the most difficult environment for our gathering, marketing, terminalling and storage activities. When the market is in contango, we will use our tankage to improve our 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 marketing margins provide an offset to this reduced cash flow. We believe that the combination of our terminalling and storage activities and gathering and marketing activities 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 whether a strong or weak market exists 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 terminalling and storage activities and our gathering and marketing activities in transitioning crude oil markets.

As use of the financial markets for crude oil has increased by producers, refiners, utilities and trading entities, risk management strategies, including those involving price hedges using NYMEX and IPE 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 crude oil purchase and sale obligations 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, IPE 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 crude oil for which we have a market, and to structure our sales contracts so that crude oil price fluctuations do not materially affect the segment profit we receive. Except for the controlled trading program discussed below, we do not acquire and hold crude oil futures contracts or other derivative products for the purpose of speculating on crude oil 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.

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 will receive mark-to-market treatment in current earnings, and result in greater potential for earnings volatility.

Geographic Data; Financial Information about Segments

See Note 13 to our Consolidated Financial Statements.

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, natural gas presents different logistical transportation challenges than crude oil; however, we believe the U.S. natural gas supply and demand situation will ultimately face storage challenges very similar to those that exist in the North American crude oil sector. We believe these factors will result in an increased need and an attractive valuation for natural gas storage facilities in order to balance market demands. From 1990 to 2004, domestic natural gas production grew approximately 5% while domestic natural gas consumption rose approximately 16%, resulting in a 160% 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 5.6 trillion cubic feet of annual net natural gas imports (or approximately 15 billion cubic feet per day) to meet its demand, nearly 1.6 times the 2004 annual shortfall.

The vast majority of the projected supply shortfall is expected to be met with imports of liquefied natural gas (LNG). According to the FERC as of January 2006, plans for 39 new LNG terminals in the United States and Bahamas have been announced, 18 of which are to be situated along the Gulf Coast. Of the 18 proposed Gulf Coast facilities, three are under construction, six have been approved by the appropriate regulatory agencies, eight have applied for approval and one has been announced.

Normal depletion of regional natural gas supplies will require additional storage capacity to pre-position natural gas supplies for seasonal usage. In addition, we believe that the growth of LNG as a supply source will also increase the demand for natural gas storage as a result of inconsistent surges and shortfalls in supply based on LNG tanker deliveries, similar in many respects to the issues associated with waterborne crude oil imports. LNG shipments are exposed to a number of risks related to natural disasters

and geopolitical factors, including hurricanes, earthquakes, tsunamis, inclement weather, labor strikes and facility disruptions, which can impact supply, demand and transportation and storage logistics. These factors are in addition to the already dramatic impact of seasonality and regional weather issues on natural gas markets.

Description of PAA/Vulcan Natural Gas Storage Assets

We believe strategically located natural gas storage facilities with multi-cycle injection and withdrawal capabilities and access to critical transportation infrastructure will play an increasingly important role in balancing the markets and ensuring reliable delivery of natural gas to the customer during peak demand periods. Our Pine Prairie facility is expected to become partially operational in 2007 and fully operational in 2009, and we believe it is well positioned to benefit from these evolving market dynamics. The facility is located near Gulf Coast supply sources and near the existing Lake Charles LNG terminal, which is the largest LNG import facility in the United States. Of the aforementioned 18 proposed new Gulf Coast facilities, six are planned for the Louisiana Gulf Coast—two are under construction, two have been approved and another two have applied for approval.

When completed, our Pine Prairie facility is expected to be a 24 Bcf salt cavern storage facility designed for high deliverability operating characteristics and multi-cycle capabilities. The site is located approximately 50 miles from the Henry Hub, the delivery point for NYMEX natural gas futures contracts, and is currently intended to interconnect with seven major pipelines serving the Midwest and the East Coast. Three additional pipelines are also located in the vicinity and offer the potential for future interconnects. We believe the facility's operating characteristics and strategic location position Pine Prairie to support the commercial functions of power generators, pipelines, utilities, energy merchants and LNG re-gasification terminal operators and provide potential customers with superior flexibility in managing their price and volumetric risk and balancing their natural gas requirements.

Our Bluewater gas storage facility, which is located in Michigan, is a depleted reservoir facility with an approximate 24 Bcf of capacity and is also strategically positioned. 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.

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.

Our investment in PAA/Vulcan is accounted for under the equity method of accounting. This investment is reflected in other long-term assets in our consolidated balance sheet and we do not consolidate any part of the assets or liabilities of PAA/Vulcan. Our share of net income or loss is reflected as one line item on the income statement and will increase or decrease, as applicable, the carrying value of our investment on the balance sheet. Distributions to the Partnership will reduce the carrying value of our investment and will be reflected on our cash flow statement. Due to the lead-time associated with constructing the Pine Prairie facility and the anticipated terms of the construction financing arrangements, we do not expect our ownership in PAA/Vulcan to have a meaningful impact on the income statement nor do we expect to receive cash distributions from PAA/Vulcan until 2009 or 2010.

Customers

Marathon Petroleum Company LLC, and its predecessor Marathon Ashland Petroleum ("MAP"), accounted for 11%, 10% and 12% of our revenues in 2005, 2004, and 2003, respectively. BP Oil Supply Company also accounted for 14% of our revenues in 2005 and 10% of our revenues in 2004. No other customers accounted for 10% or more of our revenues during 2005, 2004 or 2003. The majority of the revenues from MAP and BP Oil Supply Company pertain to our gathering, marketing, terminalling and storage operations. We believe that the loss of these customers would have only a short-term impact on our operating results. There can be no assurance, however, that we would be able to identify and access a replacement market at comparable margins.

Competition

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

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

Regulation

Our operations are subject to extensive regulations. We estimate that we are subject to regulatory oversight by over 70 federal, state, provincial and local departments and agencies, many of which are authorized by statute to issue and have issued laws and regulations binding on the oil pipeline industry, related businesses and individual participants. The failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on our operations increases our cost of doing business and, consequently, affects our profitability. However, except for certain exemptions that apply to smaller companies, we do not believe that we are affected in a significantly different manner by these laws and regulations than are our competitors. Following is a discussion of certain laws and regulations affecting us. However, due to the myriad of complex federal, state, provincial and local regulations that may affect us, directly or indirectly, you should not rely on such discussion as an exhaustive review of all regulatory considerations affecting our operations.

Pipeline and Storage Regulation

A substantial portion of our petroleum pipelines and storage tanks in the United States are subject to regulation by the U.S. Department of Transportation's ("DOT") Office of Pipeline Safety with respect to the design, installation, testing, construction, operation, replacement and management of pipeline and tank facilities. Comparable regulation exists in some states in which we conduct intrastate common carrier or private pipeline operations, as well as in Canada 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. Federal pipeline safety rules also require pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities.

In 2001, the DOT adopted the initial pipeline integrity management rule, which required operators of jurisdictional pipelines transporting hazardous liquids to develop and follow an integrity management program that provides for continual assessment of the integrity of all pipeline segments that could affect so-called "high consequence areas," including high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release, and commercially navigable waterways. In December 2003, the DOT issued a final rule requiring natural gas pipeline operators to develop similar integrity management programs for gas transmission pipelines located in high consequence areas. Segments of our pipelines transporting hazardous liquids and/or natural gas in high consequence areas are subject to these DOT rules and therefore obligate us to evaluate pipeline conditions by means of periodic internal inspection, pressure testing, or other equally effective assessment means, and to correct identified anomalies. If, as a result of our evaluation process, we determine that there is a need to provide further protection to high consequence areas, then we will be required to implement additional spill prevention, mitigation and risk control measures for our pipelines. The DOT rules also require us to evaluate and, as necessary, improve our management and analysis processes for integrating available integrity related data relating to our pipeline segments and to remediate potential problems found as a result of the required assessment and evaluation process. Costs associated with this program were approximately $4.7 million in 2005 and approximately $5 million in 2004. Based on currently available information, our preliminary estimate for 2006 is approximately $10.0 million. The relative increase in program cost over the last few years is primarily attributable to pipeline segments acquired in 2004 and 2003 (including the Link assets), which are subject to the new rules and for which assessment commenced in 2004. Certain of these costs are recurring in nature and thus will impact future periods. We will continue to refine our estimates as information from our assessments is collected. Our estimates do not include the potential costs associated with assets to be acquired in the future. 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.

The DOT is currently considering expanding the scope of its pipeline regulation to include certain gathering pipeline systems that are not currently subject to regulation. This expanded scope could include the establishment of additional pipeline integrity management programs for these newly regulated pipelines. We do not currently know what, if any, impact this will have on our operating expenses. However, we cannot assure you that future costs related to the potential programs will not be material.

During 2006, we are expanding an internal review process started in 2004 in which we are reviewing various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management rule. The purpose of this process is to review the surrounding environment, condition and operating history of these pipelines and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, we could be required (as a result of additional DOT regulation) or we may elect (as a result of our own internal initiatives) to spend substantial sums to ensure the integrity of and upgrade our pipeline systems to maintain environmental compliance, and in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines. We cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures for environmental compliance.

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

The DOT has adopted API 653 as the standard for the inspection, repair, alteration and reconstruction of existing crude oil storage tanks subject to DOT jurisdiction (approximately 77% of our 39 million barrels are subject to DOT jurisdiction). API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Full compliance is required by 2009. Costs associated with this program were approximately $4.4 million and $3 million in 2005 and 2004, respectively. Based on currently available information, we anticipate we will spend an approximate average of $10.0 million per year from 2006 through 2009 in connection with API 653 compliance activities. Such amounts incorporate the costs associated with the assets acquired in 2004 and 2003. Our estimates do not include the potential costs associated with assets to be acquired in the future. 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. 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 assure you that these security measures would fully protect our facilities from a concentrated attack. See "—Operational Hazards and Insurance."

In Canada, the NEB and provincial agencies such as the Alberta Energy and Utilities Board and the Saskatchewan Industry and Resources have promulgated regulations similar to U.S. pipeline integrity management rules and API 653 standards. In addition, we expect to incur compliance costs under other regulations related to pipeline and storage tank integrity, such as operator competency programs, regulatory upgrades to our operating and maintenance systems and environmental upgrades of buried sump tanks. We spent approximately $4.9 million in 2005 and $4.1 million in 2004 on compliance activities. Our preliminary estimate for 2006 is approximately $5.0 million. Certain of these costs are recurring in nature and thus will impact future periods. We will continue to refine our estimates as information from our assessments is collected. Our estimates do not include the potential costs associated with assets to be acquired in the future. Although we believe that our pipeline operations are in substantial compliance with currently applicable regulatory requirements, we cannot predict the potential costs associated with additional, future regulation.

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

Transportation Regulation

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

Canadian Regulation. Our Canadian pipeline assets are subject to regulation by the NEB and by provincial agencies. With respect to a pipeline over which it has jurisdiction, each of these agencies 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 agency determines that the applicable terms and conditions of service are not just and reasonable, the agency can amend the offending provisions of an existing transportation contract.

Energy Policy Act of 1992 and Subsequent Developments. In October 1992, Congress passed the Energy Policy Act of 1992 ("EPAct"), which among other things, required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for petroleum pipelines and to streamline procedures in petroleum pipeline proceedings. The FERC responded to this mandate by issuing several orders, including Order No. 561. Beginning January 1, 1995, Order No. 561 enables

petroleum pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index. Specifically, the indexing methodology allows a pipeline to increase its rates annually by a percentage equal to the change in the producer price index for finished goods ("PPI-FG") to the new ceiling level. Rate increases made pursuant to the indexing methodology are subject to protest, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. If the PPI-FG falls and the indexing methodology results in a reduced ceiling level that is lower than a pipeline's filed rate, Order No. 561 requires the pipeline to reduce its rate to comply with the lower ceiling unless doing so would reduce a rate "grandfathered" by EPAct (see below) below the grandfathered level. A pipeline must, as a general rule, utilize the indexing methodology to change its rates. The FERC, however, retained cost-of-service ratemaking, market based rates, and settlement as alternatives to the indexing approach, which alternatives may be used in certain specified circumstances. The FERC is currently reviewing its indexing methodology. If the FERC continues its policy of using the PPI-FG, changes in the PPI-FG 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 the 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 to include in its cost-of-service an income tax allowance to the extent that entity's unitholders were corporations subject to income tax. On May 4, 2005, the FERC adopted a policy statement in Docket No. PL05-5 ("Policy Statement"), stating that it would permit entities owning public utility assets, including oil pipelines, to include an income tax allowance in such utilities' cost-of-service rates to reflect the actual or potential income tax liability attributable to their public utility income, regardless of the form of ownership. Pursuant to the Policy Statement, a tax pass-through entity seeking such an income tax allowance would have to establish that its partners or members have an actual or potential income tax obligation on the entity's public utility income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the new policy is generally favorable for pipelines that are organized as pass-through entities, such as master limited partnerships ("MLPs"), it still entails rate risk due to the case-by-case review requirement. The new tax allowance policy has been appealed to the D.C. Circuit. As a result, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC's treatment of income tax allowances in cost of service. How the policy statement on income tax allowances is applied in practice to pipelines owned by MLPs, and whether it is ultimately upheld or modified on judicial review, could affect the rates of FERC regulated pipelines.

Additionally, in *BP West Coast*, the court remanded to the FERC the issue of whether SFPP's revised cost-of-service without a tax allowance would qualify as a substantially changed circumstance that would justify modification of SFPP's rates. The FERC determined in the SFPP case that its policy statement on income tax allowances does not represent a change from its pre-EPAct policy and therefore cannot be a basis for finding rates not to be grandfathered. It is not clear what impact, if any, this determination will

have on our rates or on the rates of other FERC-jurisdictional pipelines organized as tax pass-through entities. Moreover, we have no way of knowing whether the FERC's determination on this issue will withstand further FERC or judicial review. Further, we have no way of knowing what effect, if any, action by the FERC and/or the D.C. Circuit might have on our rates should they be challenged.

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

Trucking Regulation

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

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

Cross Border Regulation

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

Natural Gas Storage Regulation

Interstate Regulation. The interstate storage facilities that we have an investment in 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. The FERC also has authority over the construction and operation of U.S. transportation and storage facilities and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. Absent an exemption granted by the FERC, FERC regulations restrict access to U.S. interstate natural gas storage customer data by marketing and other energy affiliates, and place certain conditions on services provided by the U.S. storage facility operators to their affiliated gas marketing entities. These regulations affect the activities of non-regulated affiliates of PAA/Vulcan.

State Regulation. The intrastate storage facilities that we have an investment in are subject to regulation by the Michigan Public Service Commission. The Michigan State Public Service Commission has authority to regulate rates and charges for natural gas transported and stored within Michigan. The Michigan Public Service Commission also has authority over the construction and operation of transportation and storage facilities and related facilities used in the transportation, storage and sale of natural gas within Michigan, including the extension, enlargement or abandonment of such facilities.

Environmental, Health and Safety Regulation

General

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons including crude oil are subject to stringent federal, state, provincial and local laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment. As with the industry generally, compliance with these laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, and even the issuance of injunctions that may restrict or prohibit our operations. Environmental laws and regulations are subject to change, 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 property damage.

Water

The U.S. Oil Pollution Act ("OPA") subjects owners of facilities to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages, and certain other consequences of an oil spill, where such spill is into navigable waters, along shorelines or in the exclusive economic zone of the U.S. The OPA establishes a liability limit of $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. Analogous state and Canadian federal and provincial laws also impose requirements relating to the prevention of oil spills and the remediation of areas affected by spills when they occur. We believe that we are in substantial compliance with all such state and Canadian requirements.

The U.S. Clean Water Act and analogous state and Canadian federal and provincial laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters of the United States and Canada, as well as state and provincial waters. See Note 10 to our Consolidated Financial Statements. Permits must be obtained to discharge pollutants into these waters. The Clean Water Act imposes substantial potential liability for the removal and remediation of pollutants. Although we can give no assurances, we believe that compliance with existing permits and compliance with foreseeable new permit 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 requirements.

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

Air Emissions

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

Canada is a participant in the Kyoto Protocol of the United Nations Framework Convention on Climate Change. The Kyoto Protocol requires Canada to reduce its emissions of carbon dioxide and other “greenhouse gases” to six percent 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. We are currently monitoring the impact on our operations of proposed changes in regulations that will be necessary as a result of Canada’s participation in the Kyoto Protocol.

Solid Waste

We generate wastes, including hazardous wastes, that are subject to the requirements of the federal Resource Conservation and Recovery Act (“RCRA”) and comparable 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 and provincial 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. Under CERCLA, such persons may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our ordinary operations, we may generate waste that falls within CERCLA’s definition of a “hazardous substance,” in which event we may be held jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which such hazardous substances have been released into the environment.

OSHA

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

Similar regulatory requirements exist in Canada under the federal and provincial Occupational Health and Safety Acts and related regulations. The agencies with jurisdiction under these regulations are empowered to enforce them through inspection, audit, incident investigation or public or employee complaint. Additionally, recent legislation directly ties corporate accountability to the Criminal Code of Canada. This legislation enables occupational health and safety (“OH&S”) regulators to prosecute organizations and individuals criminally for violations of the regulations. We believe that our operations are in substantial compliance with applicable OH&S 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 operation 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. Similar regulation (the Species Risk Act) applies to our Canadian operations.

Hazardous Materials Transportation Requirements

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

Environmental Remediation

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

We maintain insurance of various types with varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. Consistent with insurance coverage generally available in the industry, in certain circumstances our insurance policies provide limited

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coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences.

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

The acquisitions we completed in 2005, 2004 and 2003 include a variety of provisions dealing with the allocation of responsibility for environmental costs that range from no or limited indemnities from the sellers to indemnification from sellers with defined limitations on their maximum exposure. We have not obtained insurance for any of the conditions related to our 2005 and 2003 acquisitions, and only in limited circumstances for our 2004 acquisitions.

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. A substantial portion of these environmental liabilities are associated with the former Texas New Mexico ("TNM") pipeline assets. On the effective date of the acquisition, we and TNM entered into a cost-sharing agreement whereby, on a tiered basis, we agreed to bear $11 million of the first $20 million of pre-May 1999 environmental issues. We also agreed to bear the first $25,000 per site for new sites which were not identified at the time we entered into the agreement (capped at 100 sites). TNM agreed to pay all costs in excess of $20 million (excluding the deductible for new sites). TNM's obligations are guaranteed by Shell Oil Products ("SOP"). In connection with the Link acquisition, we recorded a reserve for environmental liabilities of approximately $20.0 million.

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

In connection with our 1999 acquisition of Scurlock Permian LLC from MAP, we were indemnified by MAP for any environmental liabilities attributable to Scurlock's business or properties which 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.

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

Environmental. We have in the past experienced and in the future likely will experience releases of crude oil into the environment from our pipeline and storage operations. We also may discover environmental impacts from past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business. As we expand our pipeline assets through acquisitions, we typically improve on

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(decrease) the rate of releases from such assets as we implement our standards and procedures, remove selected assets from service and spend capital to upgrade the assets. In the immediate post-acquisition period, however, the inclusion of additional miles of pipe in our operation may result in an increase in the absolute number of releases company-wide compared to prior periods. We have, in fact, experienced such an increase in connection with the Link acquisition, which added approximately 7,000 miles of pipeline to our operations. As a result, we have also received an increased number of requests for information from governmental agencies with respect to such releases of crude oil (such as EPA requests under Clean Water Act Section 308), commensurate with the scale and scope of our pipeline operations. See Item 3. "Legal Proceedings."

At December 31, 2005, our reserve for environmental liabilities totaled approximately $22.4 million (approximately $14.6 million of this reserve is related to liabilities assumed as part of the Link acquisition). Approximately $14.4 million of our environmental reserve is classified as current and $8.0 million is classified as long-term. At December 31, 2005, we have recorded receivables totaling approximately $14.2 million for amounts recoverable under insurance and from third parties under indemnification agreements.

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

Operational Hazards and Insurance

Pipelines, terminals, trucks or other facilities or equipment may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. Since we and our predecessors commenced midstream crude oil activities in the early 1990s, we have maintained insurance of various types and varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. However, such insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. Consistent with insurance coverage generally available to the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences. Over the last several years, our operations have expanded significantly, with total assets increasing over 550% 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 may be further exacerbated by the hurricanes along the Gulf Coast during 2005, which we anticipate may also have an adverse effect on the availability and cost of coverage. As a result, we have elected to self insure more activities against certain of these operating hazards and expect this trend will continue in the future. Due to the events of September 11, 2001, insurers have excluded acts of terrorism and sabotage from our insurance policies.

On certain of our key assets, we have elected to purchase a separate insurance policy for acts of terrorism and sabotage.

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

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

Title to Properties and Rights-of-Way

We believe that we have satisfactory title to all of our assets. Although title to such properties is subject to encumbrances in certain cases, such as customary interests generally retained in connection with acquisition of real property, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens and minor easements, restrictions and other encumbrances to which the underlying properties were subject at the time of acquisition by our predecessor or 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

To carry out our operations, our general partner or its affiliates (including PMC (Nova Scotia) Company) employed approximately 2,000 employees at December 31, 2005. None of the employees of our general partner were represented by labor unions, and 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 consequences of owning and disposing of common units.

Partnership Status; Cash Distributions

We are treated for federal income tax purposes as a partnership based upon our meeting certain requirements imposed by the Internal Revenue Code (the "Code"), which we must meet each year. The owners of common units are considered partners in the Partnership so long as they do not loan their common units to others to cover short sales or otherwise dispose of those units. Accordingly, we pay no 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.

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. A unitholder is required to take into account, in determining federal income tax liability, the unitholder's share of income generated by us for each taxable year of the Partnership ending within or with the unitholder's taxable year, even if cash distributions are not made to the unitholder. As a consequence, a unitholder's share of our taxable income (and possibly the income tax payable by the unitholder with respect to such income) may exceed the cash actually distributed to the unitholder by us. At any time incentive distributions are made to the general partner, gross income will be allocated to the recipient to the extent of those distributions.

Basis of Common Units

A unitholder's initial tax basis for a common unit is generally the amount paid for the common unit. A unitholder's basis is generally increased by the unitholder's share of our income and decreased, but not below zero, by the unitholder's share of our losses and distributions.

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 ordinary income.

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 do business or own property. We own property and conduct business in Canada as well as in most states in the United States. A unitholder may be required to file Canadian federal income tax returns and to pay Canadian federal and provincial income taxes, as well as to file state income tax returns and to pay taxes in various states. A unitholder may be subject to 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 the state, may not relieve the nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

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

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

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

Available Information

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

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 purchased 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, IPE 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 crude oil, futures contracts or derivative products for the purpose of speculating on 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 pipeline linefill, which must be maintained in order to transport crude oil on our pipelines. In addition, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil. Although this activity is monitored independently by our risk management function, it exposes us to price risks within predefined limits and authorizations.

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

The nature of our business and assets exposes us to significant compliance costs and liabilities. Our asset base has more than doubled within the last two 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 at acceptable levels.

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons, including crude oil, are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment. Our segment operations are also subject to laws and regulations relating to protection of the environment, operational safety and related matters. Compliance with all of these laws and regulations increases our overall cost of doing business, including our capital costs to construct, maintain and upgrade equipment and facilities. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, the issuance of injunctions that may restrict or prohibit our operations, or claims of damages to property or persons resulting from our operations.

Today we own more than twice the miles of pipeline we owned two years ago. As we have expanded our pipeline assets, we have observed a corresponding increase in the number of releases of crude oil to the environment. These releases expose us to potentially substantial expense, including clean-up and remediation costs, fines and penalties, and third party claims for personal injury or property damage.

We currently spend substantial amounts to comply with DOT-mandated pipeline integrity rules. The DOT is currently in the process of expanding the scope of its pipeline regulation to include the establishment of additional pipeline integrity management programs for certain gathering pipeline systems that are not currently subject to regulation. We do not currently know what, if any, impact this will have on our operating expenses.

During 2006, we are expanding an internal review process started in 2004 in which we are reviewing various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management rules. The purpose of this process is to review the surrounding environment, condition and operating history of these pipeline and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, we could be required (as a result of additional DOT regulation) or we may elect (as a result of our own internal initiatives) to spend substantial sums to ensure the integrity of and upgrade our pipeline systems to maintain environmental compliance, and in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines. We cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures for environmental compliance.

Loss of credit rating or the ability to receive open credit could negatively affect our ability to capitalize on a volatile market

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

The level of our profitability is dependent upon an adequate supply of crude oil from fields located offshore and onshore California. Production from these offshore fields has experienced substantial production declines since 1995.

A significant portion of our segment profit is derived from pipeline transportation margins associated with the Santa Ynez and Point Arguello fields located offshore California. We expect that there will continue to be natural production declines from each of these fields as the underlying reservoirs are depleted. We estimate that a 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual pipeline segment profit of approximately $3.5 million. In addition, any significant production disruption from the Santa Ynez field due to production problems, transportation problems or other reasons could have a material adverse effect on our business.

The profitability of our pipeline and gathering, marketing, terminalling and storage operations depends on the volume of crude oil shipped, purchased and gathered.

Third party shippers generally do not have long-term contractual commitments to ship crude oil on our pipelines. A decision by a shipper to substantially reduce or cease to ship volumes of crude oil on our pipelines could cause a significant decline in our revenues. For example, we estimate that an average 20,000 barrel per day variance in the Basin Pipeline System within the current operating window, equivalent to an approximate 7% volume variance on that system, would change annualized segment profit by approximately $1.4 million. In addition, we estimate that an average 10,000 barrel per day variance on

the Capline Pipeline System, equivalent to an approximate 8% volume variance on that system, would change annualized segment profit by approximately $1.3 million.

To maintain the volumes of crude oil we purchase in connection with our gathering, marketing, terminalling and storage operations, we must continue to contract for new supplies of crude oil to offset volumes lost because of natural declines in crude oil production from depleting wells or volumes lost to competitors. Replacement of lost volumes of crude oil is particularly difficult in an environment where production is low and competition to gather available production is intense. Generally, because producers experience inconveniences in switching crude oil purchasers, such as delays in receipt of proceeds while awaiting the preparation of new division orders, producers typically do not change purchasers on the basis of minor variations in price. Thus, we may experience difficulty acquiring crude oil at the wellhead in areas where relationships already exist between producers and other gatherers and purchasers of crude oil. We estimate that a 15,000 barrel per day decrease in barrels gathered by us would have an approximate $4.0 million per year negative impact on segment profit. This impact assumes a reasonable margin throughout various market conditions. Actual margins vary based on the location of the crude oil, the strength or weakness of the market and the grade or quality of crude oil. We estimate that a $0.01 variance in the average segment profit per barrel would have an approximate $2.5 million annual effect on segment profit.

The success of our business strategy to increase and optimize throughput on our pipeline and gathering assets is dependent upon our securing additional supplies of crude oil.

Our operating results are dependent upon securing additional supplies of crude oil from increased production by oil companies and aggressive lease gathering efforts. The ability of producers to increase production is dependent on the prevailing market price of oil, the exploration and production budgets of the major and independent oil companies, the depletion rate of existing reservoirs, the success of new wells drilled, environmental concerns, regulatory initiatives and other matters beyond our control. There can be no assurance that production of crude oil will rise to sufficient levels to cause an increase in the throughput on our pipeline and gathering assets.

Fluctuations in demand can negatively affect our operating results.

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

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

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

Our ability to grow depends in part on our ability to make acquisitions that result in an increase in adjusted operating surplus per unit. If we are unable to make such accretive acquisitions either because we are (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (ii) unable to raise financing for such acquisitions on economically acceptable terms or (iii) outbid by competitors, our future growth will be limited. In particular, competition for midstream assets and businesses has intensified substantially and as a consequence such assets and businesses have become more

costly. As a result, we may not be able to complete the number or size of acquisitions that we have targeted internally or to continue to grow as quickly as we have historically.

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

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

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

Any acquisition involves potential risks, including:

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

· a significant increase in our indebtedness and working capital requirements;

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

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

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

· customer or key employee loss from the acquired businesses; and

· the diversion of management's attention from other business concerns.

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

Our pipeline assets are subject to federal, state and provincial regulation.

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

Similarly, our Canadian pipeline assets are subject to regulation by the NEB and by provincial agencies. With respect to a pipeline over which it has jurisdiction, each of these Canadian agencies has the power to determine the rates we are allowed to charge for transportation on such pipeline. The extent to which regulatory agencies can override existing transportation contracts has not been fully decided.

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

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.) EPAct further protects any rate meeting this requirement from complaint unless the complainant can show that a substantial change occurred after the enactment of EPAct in the economic circumstances of the oil pipeline which were the basis for the rate or in the nature of the services provided which were a basis for the rate. This grandfathering protection does not apply, under certain specified circumstances, when the person filing the complaint was under a contractual prohibition against the filing of a complaint.

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

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

We face competition in our pipeline and gathering, marketing, terminalling and storage activities.

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

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

There can be no assurance that we have adequately assessed the credit worthiness of our existing or future counterparties or that there will not be an unanticipated deterioration in their credit worthiness, 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.

Our pipeline systems are dependent upon their interconnections with other crude oil pipelines to reach end markets.

In many cases, the crude oil carried on our pipeline system must be routed onto third party pipelines to reach the refinery or other end market. Reduced throughput on these interconnecting pipelines as a result of testing, line repair, reduced operating pressures or other causes could result in reduced throughput on our pipeline systems that would adversely affect our profitability.

We may in the future encounter increased costs 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, which adversely impacted the availability and costs of certain types of coverage. We anticipate that the effects of hurricanes along the Gulf Coast during 2005 may also have an adverse effect on the availability and cost 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 has inherent operating risks.

Our gathering and marketing operations include purchasing crude oil that is carried on third party tankers. Our water borne 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. While 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, which could result in a reduction in the market price of our equity or debt securities.

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

Maritime claimants could arrest the vessels carrying our cargoes.

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

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

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

As of December 31, 2005, our total outstanding long-term debt was approximately $951.7 million. Various limitations in our debt instruments may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

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

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

Risks Related to Our Investment in the Natural Gas Storage Business

Our facilities are new and have limited operating history.

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

We have no history operating natural gas storage facilities.

Although many aspects of the natural gas storage industry are similar in many respects to our crude oil gathering, marketing, terminalling and storage operations, our current management does not have any experience in operating natural gas storage facilities. There are significant risks and costs inherent in our efforts to undertake entering into natural gas storage operations, including the risk that our new line of business may not be profitable and that we might not be able to operate the natural gas storage business or implement our operating policies and strategies successfully.

The devotion of capital, management time and other resources to natural gas storage operations could adversely affect our existing business. Entering into the natural gas storage industry may require substantial changes, including acquisition costs, capital development expenditures, adding management and employees who possess the skills we believe we will need to operate a natural gas storage business, and realigning our current organization to reflect this new line of business. Entering into the natural gas storage industry will require an investment in personnel and assets and the assumption of risks that may be greater than we have previously assumed.

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

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

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

We depend on third party pipelines to move natural gas for our customers to and from our facilities. Any interruption of service on the pipelines or lateral connections or adverse change in the terms and

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

We encounter competition from a variety of sources.

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. Construction of new capacity could have an adverse impact on our competitive position.

Expanding our business by constructing new storage facilities subjects us to construction risks; there is no guarantee that Pine Prairie will be developed in the expected time frame or at the expected cost or generate the expected returns.

One of the ways we intend to grow our business is through the construction and development of new storage facilities or additions to our existing facilities. The construction of additional storage facilities or new pipeline interconnects involves numerous regulatory, environmental, political and legal uncertainties beyond our control, and requires the expenditure of significant amounts of capital. As we undertake these projects, they may be completed behind schedule or over the budgeted cost. Because of continuing increased demand for materials, equipment and services in the wake of Hurricanes Katrina and Rita, there could be shortages and cost increases associated with construction projects. Moreover, our revenues will not increase immediately upon the expenditure of funds on a particular project. We may also construct facilities in anticipation of market growth that may never materialize. For example, Pine Prairie is currently under development and there is no guarantee that it will be fully developed in the expected time frame or at the expected cost or generate the expected returns.

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

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

Third parties' obligations under storage agreements may be suspended in some circumstances.

Some third parties' obligations under their agreements with us may be permanently or temporarily reduced upon the occurrence of certain events, some of which are beyond our control, including force majeure. Force majeure events include (but are not limited to) revolutions, wars, acts of enemies, embargoes, import or export restrictions, strikes, lockouts, fires, storms, floods, acts of God, explosions and mechanical or physical failures of our equipment or facilities or the equipment or facilities of third parties.

The nature of our investment in natural gas storage assets and business could expose us to significant compliance costs and liabilities.

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 natural gas storage

operations are also subject to laws and regulations otherwise relating to protection of the environment, operational safety and related matters. Compliance with all of these laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, and the issuance of injunctions that may restrict or prohibit our operations or even claims of damages to property or persons resulting from our operations. The laws and regulations applicable to our operations are subject to change, 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 materials 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 liability to private parties for personal injury or property damage.

Joint venture structures can create operational difficulties.

Our natural gas storage operations are conducted through PAA/Vulcan, a joint venture between us and a subsidiary of Vulcan Capital, with each of us owning 50%. The board of directors of PAA/Vulcan, which includes an equal number of representatives from us and Vulcan Gas Storage, will be responsible for providing strategic direction and policy making, and we are responsible for the day-to-day operations.

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

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

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

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

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

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

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

Our general partner manages and operates Plains All American Pipeline, L.P. 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 other continuing basis.

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

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

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

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

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

Our general partner may cause us to issue an unlimited number of common units, without unitholder approval. We may also issue at any time an unlimited number of equity securities ranking junior or senior to the common units without unitholder approval. 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 Plains All American Pipeline, L.P. 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.

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 subsidiaries, other than PAA Finance Corp., the co-issuer of our debt securities, 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, 2005, our total outstanding long-term debt and short-term debt under our revolving credit facility were approximately $1.1 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 entity-level taxation by individual states. If the IRS were to treat us as a corporation or if we become subject to entity-level taxation for state tax purposes, it would reduce the amount of cash available for distribution to our unitholders.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to our unitholders would generally be taxed again to them as corporate distributions, and no income, gains, losses, deductions or credits would flow through to them. Because a tax would be imposed upon us as a corporation, the cash available for distribution to our unitholders would be substantially reduced. Treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of the common units. Moreover, treatment of us as a corporation could materially and adversely affect our ability to make cash distributions to our unitholders or to make payments on our debt securities.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to our unitholders would be reduced. 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, state or local income tax purposes, then the minimum quarterly distribution and the target distribution levels will be adjusted to reflect the impact of that law on us.

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

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

Our unitholders may be required to pay taxes even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, they will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they do not receive any cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income.

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

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

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

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

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

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

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

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including foreign taxes, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property and in which they do not reside. We own property and conduct business in Canada and in most states in the United States. Unitholders may be required to file Canadian federal income tax returns and to pay Canadian federal and provincial income taxes and to file state and local income tax returns and pay state and local income taxes in many or all of the jurisdictions in which we do business or own property. Further, unitholders may be subject to penalties for failure to comply with those requirements. It is our unitholders’ responsibility to file all United States federal, state, local and foreign tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in the common units.

Item 1B. *Unresolved Staff Comments*

None.

Item 3. *Legal Proceedings*

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the “short supply” controls of the Export Administration Regulations (“EAR”) and must be licensed by the Bureau of Industry and Security (the “BIS”) of the U.S. Commerce Department. In 2002, we determined that we may have violated the terms of our licenses with respect to the quantity of crude oil exported and the end-users in Canada. Export of crude oil except as authorized by license is a violation of the EAR. In October 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and received several new licenses allowing for export volumes and end users that more accurately reflect our anticipated business and customer needs. We also conducted reviews of new and existing contracts and implemented new procedures and practices in order to monitor compliance with applicable laws regarding the export of crude oil to Canada. As a result, we subsequently submitted additional information to the BIS in October 2003 and May 2004. In August 2004, we received a request from the BIS for additional information. We have responded to this and subsequent requests, and continue to cooperate fully with BIS officials. At this time, we have received neither a warning letter nor a charging letter, which could involve the imposition of penalties, and no indication of what penalties the BIS might assess. As a result, we cannot reasonably estimate the ultimate impact of this matter.

Pipeline Releases. In December 2004 and January 2005, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. 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 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 both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains Pipeline, the U.S. Environmental Protection Agency, the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 4,200 barrels and 980 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 $4.5 million to $5.0 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. We have been informed by EPA that it has referred these two crude oil releases, as well as several other smaller releases, to the U.S. Department of Justice for further investigation in connection with a possible civil penalty enforcement action under the Federal Clean Water Act.

Other. We, in the ordinary course of business, are a claimant and/or a defendant in various other legal proceedings. We do not believe that the outcome of these other legal proceedings, individually and in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

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

There were no matters submitted to a vote of unitholders during the fourth quarter of 2005.

PART II

Item 5. *Market For the 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 17, 2006, the closing market price for our common units was $44.40 per unit and there were approximately 49,000 record holders and beneficial owners (held in street name). As of February 17, 2006, there were 73,768,576 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)]
2005			
1st Quarter	$ 40.98	$ 36.50	$ 0.6375
2nd Quarter	45.08	38.00	0.6500
3rd Quarter	48.20	42.01	0.6750
4th Quarter	42.82	38.51	0.6875
2004			
1st Quarter	$ 35.23	$ 31.18	$ 0.5625
2nd Quarter	36.13	27.25	0.5775
3rd Quarter	35.98	31.63	0.6000
4th Quarter	37.99	34.51	0.6125

(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, both in the form of grants of options and phantom units. Additional information regarding our equity compensation plans is included in Part III of this report under Item 11. "Executive Compensation" and Item 13. "Certain Relationships and Related Transactions."

Cash Distribution Policy

We will distribute to our unitholders, on a quarterly basis, all of our available cash 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, 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. We paid $15.0 million to the general partner in incentive distributions in 2005. On

February 14, 2006, we paid a quarterly distribution of $0.6875 per unit applicable to the fourth quarter of 2005. See Item 13. "Certain Relationships and Related Transactions—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 2005.

Item 6. ***Selected Financial and Operating Data***

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2005, 2004, 2003, 2002, and 2001 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,				
	2005	2004	2003	2002	2001
	(in millions, except per unit data)				
Statement of operations data:					
Total Revenues[1]	$ 31,177.3	$ 20,975.5	$ 12,589.9	$ 8,384.2	$ 6,868.2
Crude oil and LPG purchases and related costs[1]	(29,691.9)	(19,870.9)	(11,746.4)	(7,741.2)	(6,348.3)
Pipeline margin activities purchases[1]	(750.6)	(553.7)	(486.1)	(362.3)	(270.8)
Field Operating costs (excluding LTIP charge)	(269.4)	(218.6)	(134.2)	(106.4)	(106.8)
LTIP charge-operations[2]	(3.1)	(0.9)	(5.7)	—	—
General and administrative expenses (excluding LTIP charge)	(80.2)	(75.7)	(50.0)	(45.7)	(46.6)
LTIP charge-general and administrative[2]	(23.0)	(7.0)	(23.1)	—	—
Depreciation and amortization	(83.5)	(68.7)	(46.2)	(34.0)	(23.3)
Total costs and expenses	(30,901.7)	(20,795.5)	(12,491.7)	(8,289.6)	(6,795.8)
Operating income	275.6	180.0	98.2	94.6	72.4
Equity earnings in PAA/Vulcan Gas Storage, LLC	1.0	—	—	—	—
Interest expense	(59.4)	(46.7)	(35.2)	(29.1)	(29.1)
Interest and other income (expense),net	0.6	(0.2)	(3.6)	(0.2)	0.4
Income before cumulative effect of change in accounting principle[3]	$ 217.8	$ 133.1	$ 59.4	$ 65.3	$ 43.7
Basic Net Income per limited partner unit before cumulative effect of change in accounting principle[3]	$ 2.77	$ 1.94	$ 1.01	$ 1.34	$ 1.12
Diluted Net Income per limited partner unit before cumulative effect of change in accounting principle[3]	$ 2.72	$ 1.94	$ 1.00	$ 1.34	$ 1.12
Basic weighted average number of limited partner units outstanding	69.3	63.3	52.7	45.5	37.5
Diluted weighted average number of limited partner units outstanding	70.5	63.3	53.4	45.5	37.5
Balance sheet data (at end of period):					
Total assets	$ 4,120.3	$ 3,160.4	$ 2,095.6	$ 1,666.6	$ 1,261.2
Total long-term debt[4]	951.7	949.0	519.0	509.7	354.7
Total debt	1,330.1	1,124.5	646.3	609.0	456.2
Partners' capital	1,330.7	1,070.2	746.7	511.6	402.8

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(in millions, except per unit data and volumes)				
Other data:					
Maintenance capital expenditures	$ 14.0	$ 11.3	$ 7.6	$ 6.0	$ 3.4
Net cash provided by (used in) operating activities[5]	24.1	104.0	115.3	185.0	(16.2)
Net cash provided by (used in) investing activities[5]	(297.2)	(651.2)	(272.1)	(374.9)	(263.2)
Net cash provided by (used in) financing activities	270.6	554.5	157.2	189.5	279.5
Distributions per limited partner unit[6] [7]	2.58	2.30	2.19	2.11	1.95
Operating Data:					
Volumes (thousands of barrels per day)[8]					
Pipeline segment:					
Tariff activities					
All American	51	54	59	65	69
Basin	290	265	263	93	N/A
Capline	132	123	N/A	N/A	N/A
Cushing to Broome	66	N/A	N/A	N/A	N/A
North Dakota/Trenton	77	39	N/A	N/A	N/A
West Texas/New Mexico Area Systems[9]	428	338	189	104	N/A
Canada	255	263	203	187	132
Other	426	330	110	115	144
Pipeline margin activities	74	74	78	73	61
Total	1,799	1,486	902	637	406
Gathering, marketing, terminalling and storage segment:					
Crude oil lease gathering	610	589	437	410	348
LPG sales	56	48	38	35	19

(1) Includes buy/sell transactions. See Note 2 to our Consolidated Financial Statements.

(2) Compensation expense related to our 1998 Long-Term Incentive Plan ("1998 LTIP") and our 2005 Long-Term Incentive Plan ("2005 LTIP"). See Item 11. "Executive Compensation—Long-Term Incentive Plans."

(3) Income from continuing operations before cumulative effect of change in accounting principle pro forma for the impact of our January 1, 2004 change in our method of accounting for pipeline linefill in third party assets would have been $61.4 million, $64.8 million and $38.4 million for 2003, 2002 and 2001, respectively. 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), $1.33 ($1.33 diluted) and $0.97 ($0.97 diluted) for 2003, 2002 and 2001 respectively.

(4) Includes current maturities of long-term debt of $9.0 million and $3.0 million at December 31, 2002 and 2001, respectively, classified as long-term because of our ability and intent to refinance these amounts under our long-term revolving credit facilities.

(5) In conjunction with the change in accounting principle we adopted as of January 1, 2004, we have reclassified cash flows for 2003 and prior years 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.

(6) Distributions represent those declared and paid in the applicable year.

(7) Our general partner is entitled 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.

(8) 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.

(9) The aggregate of multiple systems in the West Texas/New Mexico area.

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
- Acquisitions and Internal Growth Projects
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements and Change in Accounting Principle
- Results of Operations
- Outlook
- Liquidity and Capital Resources
- Off-Balance Sheet Arrangements

Executive Summary

Company Overview

We are engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other natural gas related petroleum products. We have an extensive network of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins, transportation corridors and at major market hubs in the United States and Canada. In addition, through our 50% equity ownership in PAA/Vulcan, we are engaged in the development and operation of natural gas storage facilities. We were formed in September 1998, and our operations are conducted directly and indirectly through our primary operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P.

We are one of the largest midstream crude oil companies in North America. As of December 31, 2005, we owned approximately 15,000 miles of active crude oil pipelines, approximately 39 million barrels of active terminalling and storage capacity and approximately 500 transport trucks. Currently, we handle an average of over 3.0 million barrels per day of physical crude oil through our extensive network of assets located in major oil producing regions of the United States and Canada.

Our operations consist of two operating segments: (i) pipeline transportation operations ("Pipeline") and (ii) gathering, marketing, terminalling and storage operations ("GMT&S"). Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and we operate certain terminalling and storage assets.

Overview of Operating Results, Capital Spending and Significant Activities

During 2005, we recognized net income of $217.8 million and earnings per diluted limited partner unit of $2.72, compared to $130.0 million and $1.89, respectively during 2004. Both 2005 and 2004 were substantial increases over 2003. The results for 2005 as compared to the two previous years were significantly impacted by increased segment profit in both of our operating segments. Key items impacting 2005 include:

- Favorable market conditions characterized by relatively strong contango market conditions and significantly high volatility in price and market structure of crude oil.

- Increased contributions to both of our operating segments attributable to a full year of operation of businesses acquired in 2004 and the realization of synergies from those businesses.
- The inclusion in 2005 of an aggregate charge of approximately $26.1 million related to our Long-Term Incentive Plans. See "—Critical Accounting Policies and Estimates—Long-Term Incentive Plan Accruals."
- A loss of approximately $18.9 million in 2005 resulting from the mark-to-market of open derivative instruments pursuant to Statement of Financial Accounting Standard No. 133, as amended ("SFAS 133").
- The impact of Hurricanes Katrina and Rita. Our estimates indicate that the negative effect of these hurricanes was approximately $8-10 million (including approximately $3.7 million of operating costs, net of estimated insurance reimbursements). This includes disruptions to our operations and uninsured damage to some of our terminals and other facilities. On an overall basis, the hurricanes did not have a material impact on our revenue-generating capacity.
- We continued to develop internal growth projects to optimize and expand our presence in our operating areas, while continuing to pursue strategic and accretive acquisitions. These activities totaled $304.4 million in 2005 and included the formation of a joint venture (PAA/Vulcan) that made an acquisition of natural gas storage facilities. See "—Acquisitions and Internal Growth Projects."
- In addition, we maintained the relative strength of our overall capital structure and increased liquidity through a series of equity issuances and senior notes issuances. We also expanded and extended the size and maturity of our credit facilities. See "—Liquidity and Capital Resources."

Prospects for the Future

We believe that our terminalling and storage activities and our gathering and marketing activities are counter-cyclical. We believe that this balance of activities, combined with our pipeline transportation operations, generally provides us with the flexibility to maintain a base level of margin irrespective of whether a strong or weak market exists and, in certain circumstances, to realize incremental margin during volatile market conditions.

During 2005, we strengthened our business by expanding our asset base through acquisitions and internal growth projects. In 2006, we intend to spend approximately $230 million on internal growth projects and also to continue to develop our inventory of projects for implementation beyond 2006. We believe the outlook is positive for, and have a strategic initiative of increasing our participation in, the importation of foreign crude oil, primarily through building a meaningful asset presence to enable us to receive foreign crude oil via the Gulf Coast. We also believe there are opportunities for us to grow our LPG business. In addition, our recent entry into the natural gas storage business is consistent with our stated strategy of leveraging our assets, business model, knowledge and expertise into businesses that are complementary to our existing activities. We will continue to look for ways to grow the natural gas storage

business and continue to evaluate opportunities in other complementary midstream business activities. 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 the North American midstream infrastructure.

Although we believe that we are well situated in the North American midstream infrastructure, we face various operational, regulatory and financial 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 crude oil assets, and we will also continue to initiate expansion projects designed to optimize crude oil 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."

Acquisitions and Internal Growth Projects

We completed a number of acquisitions and capital expansion projects in 2005, 2004 and 2003 that have impacted our results of operations and liquidity discussed herein. The following table summarizes our capital expenditures for the periods indicated (in millions):

	2005	2004	2003
Acquisition capital[(1)]	$ 40.3	$ 563.9	$ 183.8
Investment in PAA/Vulcan Gas Storage, LLC	112.5	—	—
Internal growth projects	148.8	117.3	55.5
Maintenance capital	14.0	11.3	7.6
Total	$ 315.6	$ 692.5	$ 246.9

(1) Acquisition capital includes deposits in the year the acquisition closed, rather than the year the deposit was paid. Deposits paid were approximately $12 million for the Shell Gulf Coast Pipeline Systems acquisition in 2004 and approximately $16 million for the Capline acquisition in 2003.

Internal Growth Projects

During 2004 and 2005 we increased our focus on expansion and internal growth opportunities. We increased our annual level of spending on these projects over 100% in 2004 from 2003 and increased an additional 25% in 2005 over the amount spent in 2004. The following table summarizes our 2005 and 2004 projects (in millions):

Projects	2005	2004
Trenton pipeline expansion	$ 31.8	$ 11.8
St. James terminal	15.2	—
Cushing to Broome pipeline	8.2	39.2
Northwest Alberta fractionator	15.6	—
Cushing Phase IV and V expansions	11.2	9.4
Link acquisition asset upgrades	9.3	4.8
Kerrobert tank expansion	4.3	—
Other expansion projects	53.2	52.1
Total internal growth projects	$ 148.8	$ 117.3

Our 2005 projects included the construction and expansion of pipeline systems, crude oil storage facilities and the construction of a natural gas liquids fractionator. With the exception of the Cushing to Broome Pipeline and the Trenton Pipeline expansion, the 2005 revenue contribution associated with the 2005 projects discussed above were minimal, but we expect revenue contribution to increase in 2006

and further increase in 2007. We expect to continue our focus on internal growth projects during 2006. See "—Liquidity and Capital Resources—2006 Capital Expansion Projects."

Acquisitions

The following acquisitions were accounted for, and the purchase prices were allocated, in accordance with SFAS 141, "Business Combinations," unless otherwise noted. See Note 3 to our Consolidated Financial Statements for additional information about our acquisition activities. The majority of our acquisitions were initially financed with borrowings under our credit facilities, which were subsequently repaid with portions of the proceeds from equity issuances 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 tables below. Our ongoing acquisitions and capital expansion activities are discussed further in "—Liquidity and Capital Resources."

2005 Acquisitions

We completed six small transactions in 2005 for aggregate consideration of approximately $40.3 million. The transactions included 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 our acquisitions that were completed in 2005 (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Shell Gulf Coast Pipeline Systems[1]	1/1/2005	$ 12.0	Pipeline
Tulsa LPG Pipeline	3/2/2005	10.0	GMT&S
Other acquisitions	Various	18.3	Pipeline/GMT&S
Total		$ 40.3	

(1) 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 $112.5 million capital contribution to PAA/Vulcan and we account for the 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."

2004 Acquisitions

In 2004, we completed several acquisitions for aggregate consideration of approximately $563.9 million. The Link and Capline acquisitions were material to our operations. See Note 3 to our Consolidated Financial Statements. The following table summarizes our acquisitions that were completed in 2004, and a description of our material acquisitions follows the table (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Capline and Capwood Pipeline Systems ("Capline acquisition")[1]	03/01/04	$ 158.5	Pipeline
Link Energy LLC ("Link acquisition")	04/01/04	332.3	Pipeline/ GMT&S
Cal Ven Pipeline System	05/01/04	19.0	Pipeline
Schaefferstown Propane Storage Facility[2]	08/25/04	46.4	GMT&S
Other	various	7.7	GMT&S
Total		$ 563.9	

(1) Includes deposit of approximately $16 million which was paid in December 2003 for the Capline acquisition.

(2) Includes approximately $14.4 million of LPG operating inventory acquired.

Capline and Capwood Pipeline Systems. The principal assets acquired are: (i) an approximate 22% undivided joint interest in the Capline Pipeline System, and (ii) an approximate 76% undivided joint interest in the Capwood Pipeline System. The Capline Pipeline System is a 633-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capwood Pipeline System is a 57-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois. These pipelines provide one of the primary transportation routes for crude oil shipped into the Midwestern U.S. and delivered to several refineries and other pipelines.

Link Energy LLC. The Link crude oil business we acquired consisted of approximately 7,000 miles of active crude oil pipeline and gathering systems, over 10 million barrels of active crude oil storage capacity, a fleet of approximately 200 owned or leased trucks and approximately 2 million barrels of crude oil linefill and working inventory. The Link assets complement our assets in West Texas and along the Gulf Coast and allow us to expand our presence in the Rocky Mountain and Oklahoma/Kansas regions.

2003 Acquisitions

During 2003, we completed ten acquisitions for aggregate consideration of approximately $183.8 million (including an accrual for the deferred purchase price of a 2001 acquisition). The aggregate consideration includes cash paid, estimated transaction costs, assumed liabilities and estimated near-term capital costs. These acquisitions did not materially impact our results of operations, either individually or in the aggregate. The following table summarizes our acquisitions that were completed in 2003 (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Red River Pipeline System	02/01/03	$ 19.4	Pipeline
Iatan Gathering System	03/01/03	24.3	Pipeline
South Louisiana Assets	06/01/03	13.4	Pipeline/ GMT&S
Iraan to Midland Pipeline System	06/30/03	17.6	Pipeline
ArkLaTex Pipeline System	10/01/03	21.3	Pipeline
South Saskatchewan Pipeline System	11/01/03	47.7	Pipeline
CANPET acquisition deferred purchase price(1)	12/31/03	24.3	GMT&S
Other acquisitions	various	15.8	Pipeline/ GMT&S
Total		$ 183.8	

(1) In connection with the CANPET acquisition in 2001, a portion of the purchase price was deferred subject to various performance criteria. These objectives were met as of December 31, 2003.

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 policies 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 less than 2% of total annual revenues and cost of sales are recorded using estimates and less than 6.5% of total quarterly 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 both an annual and quarterly basis. 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 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. Less than 1% of total 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.

Contingent Liability Accruals. We accrue reserves for contingent liabilities including, but not limited to, environmental remediation and governmental penalties, insurance claims, asset retirement obligations 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 10% in our aggregate estimate for the contingent liabilities discussed above would have an approximate $3 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 141, 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.

Long-Term Incentive Plan ("LTIP") Accruals. We also make accruals for potential payments under our 2005 LTIP and 1998 LTIP plans when we determine that vesting of the common units granted under these plans is probable. The aggregate amount of the actual charge to expense will be determined by the unit price on the date vesting occurs (or, in some cases, the average unit price for a range of dates) multiplied by the number of units, plus our share of associated employment taxes. Uncertainties involved in this accrual include whether or not we actually achieve the specified performance requirements, the actual unit price at time of settlement and the continued employment of personnel subject to the vestings. We have concluded that it is probable that we will achieve a $3.00 annualized distribution rate and therefore have accelerated the recognition of compensation expense related to the portion of the awards that vest up to that rate. Under generally accepted accounting principles, we are required to recognize expense when it is considered probable that phantom unit grants under the LTIP plans will vest. As a result, we recognized total compensation expense of approximately $26.1 million in 2005 and $7.9 million in 2004 related to the awards granted under our 1998 LTIP and our 2005 LTIP plans. A change in our unit price of $1 from the amount we used to record our accrual would have an impact of approximately $2.2 million on our operating income. We cannot provide assurance that actual amounts will not vary significantly from estimated amounts. See Note 9 to our Consolidated Financial Statements.

Recent Accounting Pronouncements and Change in Accounting Principle

Recent Accounting Pronouncements

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

Change in Accounting Principle

Effective January 1, 2004, we changed our method of accounting for pipeline linefill in third party assets. Previously, we had viewed pipeline linefill, whether in our assets or third party assets, as having long-term characteristics rather than characteristics typically associated with the short-term classification of operating inventory. Therefore, previously we did not include linefill barrels in the same average costing calculation as our operating inventory, but instead carried linefill at historical cost. Following this change in accounting principle, the linefill in third party assets that we historically classified as a portion of "Pipeline Linefill" on the face of the balance sheet (a long-term asset) and carried at historical cost, is included in "Inventory" (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we reclassify the linefill in third party assets not expected to be liquidated within the succeeding twelve months out of "Inventory" (a current asset), at average cost, and into "Inventory in Third Party Assets" (a long-term asset), which is now reflected as a separate line item within other assets on the consolidated balance sheet.

This change in accounting principle was effective January 1, 2004 and is reflected in our consolidated statement of operations for the year ended December 31, 2004 and our consolidated balance sheet as of December 31, 2004. The cumulative effect of this change in accounting principle as of January 1, 2004, is a charge of approximately $3.1 million, representing a reduction in Inventory of approximately $1.7 million, a reduction in Pipeline Linefill of approximately $30.3 million and an increase in Inventory in Third Party Assets of $28.9 million. The pro forma impact for the year ended December 31, 2003 is detailed below:

	Reported Year Ended December 31, 2003	Impact of Change in Accounting Principle Year Ended December 31, 2003	Pro Forma Year Ended December 31, 2003
	(in millions, except per unit amounts)		
Net income	$ 59.5	$ 2.0	$ 61.5
Basic income per limited partner unit	$ 1.01	$ 0.04	$ 1.05
Diluted income per limited partner unit	$ 1.00	$ 0.04	$ 1.04

Results of Operations

Analysis of Operating Segments

Our operations consist of two operating segments: (i) Pipeline and (ii) GMT&S. Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain, and we operate certain terminalling and storage assets. We believe that the combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flow. In a contango market (oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (oil prices for future deliveries are lower than for current deliveries), we use less storage capacity, but increased marketing margins (premiums for prompt delivery resulting from higher demand) provide an offset to this reduced 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 whether a strong or weak market exists and, in certain circumstances, to realize incremental margin during volatile market conditions.

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues 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. Therefore, 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. Management compensates for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance costs, which mitigate the actual decline in the value of our principal fixed assets. These maintenance costs 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 or expand the operating capacity are charged to expense as incurred. See Note 13 to our Consolidated Financial Statements for a reconciliation of segment profit to consolidated income before cumulative effect of change in accounting principle.

Pipeline Operations

As of December 31, 2005, we owned approximately 15,000 miles (of which approximately 13,000 miles are included in our pipeline segment) of active gathering and mainline crude oil pipelines located throughout the United States and Canada. Our activities from pipeline operations generally consist of transporting volumes of crude oil for a fee and third party leases of pipeline capacity (collectively referred to as "tariff activities"), as well as barrel exchanges and buy/sell arrangements (collectively referred to as "pipeline margin activities"). In connection with certain of our merchant activities conducted under our gathering and marketing business, we are also shippers on certain of our own pipelines. These transactions are conducted at published tariff rates and eliminated in consolidation. 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, barrel exchanges and buy/sell arrangements generally reflect a negotiated amount.

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

	Year Ended December 31,		
	2005	2004	2003
		(in millions)	
Operating Results[(1)]			
Revenues			
Tariff activities	$ 357.6	$ 299.7	$ 153.3
Pipeline margin activities[(2)]	772.7	575.2	505.3
Total pipeline operations revenues	1,130.3	874.9	658.6
Costs and Expenses			
Pipeline margin activities purchases[(3)]	(751.5)	(554.6)	(487.1)
Field operating costs (excluding LTIP charge)	(152.4)	(121.1)	(60.9)
LTIP charge—operations	(1.0)	(0.1)	(1.4)
Segment G&A expenses (excluding LTIP charge)[(4)]	(39.6)	(38.1)	(18.3)
LTIP charge—general and administrative[(4)]	(10.6)	(3.8)	(9.6)
Segment profit	$ 175.2	$ 157.2	$ 81.3
Maintenance capital	$ 8.4	$ 8.3	$ 6.4
Average Daily Volumes (thousands of barrels per day)[(5)]			
Tariff activities			
All American	51	54	59
Basin	290	265	263
Capline	132	123	N/A
Cushing to Broome	66	N/A	N/A
North Dakota/Trenton	77	39	N/A
West Texas/New Mexico Area Systems[(6)]	428	338	189
Canada	255	263	203
Other	426	330	110
Total tariff activities	1,725	1,412	824
Pipeline margin activities	74	74	78
Total	1,799	1,486	902

(1) Revenues and purchases include intersegment amounts.

(2) Pipeline margin activities includes revenues associated with buy/sell arrangements of $197.1 million, $149.8 million and $166.2 million for the years ended December 31, 2005, 2004 and 2003, respectively. Volumes associated with these arrangements were approximately 16,000, 12,000 and 17,000 barrels per day for the years ended December 31, 2005, 2004 and 2003, respectively. See Note 2 to our Consolidated Financial Statements.

(3) Pipeline margin activities purchases includes purchases associated with buy/sell arrangements of $196.2 million $142.5 million and $159.2 million for the years ended December 31, 2005, 2004 and 2003, respectively. Volumes associated with these arrangements were approximately 16,000, 12,000 and 17,000 barrels per day for the years ended December 31, 2005, 2004 and 2003, respectively. See Note 2 to our Consolidated Financial Statements.

(4) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each year.

(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 period.

(6) The aggregate of multiple systems in the West Texas/New Mexico area.

Total revenues for our pipeline segment have increased over the three-year period ended December 31, 2005. The revenue increase in 2005 relates both to our tariff activities and to our margin activities. The increase in revenues from tariff activities in the 2004 period is primarily related to increased volumes resulting from our acquisition activities as discussed further below. The increase in revenues from our margin activities in 2005 and 2004 is related to higher average prices for crude oil sold and transported on our San Joaquin Valley gathering system in each of the years compared to the prior year. The increase in 2005 was also favorably impacted by an increase in buy/sell volumes as compared to the applicable prior year. Because the barrels that we buy and sell are generally indexed to the same pricing indices, revenues and purchases will increase and decrease with changes in market prices without significant changes to our margins related to those purchases and sales.

Segment profit, our primary measure of segment performance, was impacted by the following:

- Increased volumes and related tariff revenues—The increase in volumes and related tariff revenues during 2005 primarily relates to the Link acquisition and other acquisitions completed during 2005 and 2004. This increase primarily resulted from the inclusion of the related assets for the entire 2005 period versus only a portion of the 2004 period. The increase in volumes and related tariff revenues in 2004 versus 2003 is primarily related to the Link acquisition, the Capline acquisition and other acquisitions completed during 2004 and late 2003.
- Increased revenues from our loss allowance oil—As is common in the industry, our crude oil tariffs incorporate a “loss allowance factor” intended to offset losses due to evaporation, measurement and other losses in transit. The loss allowance factor averages approximately 0.2% by volume. We value the variance of allowance volumes to actual losses at the average market value at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. Gains or losses on sales of allowance oil barrels are also included in tariff revenues. Revenues related to loss allowance oil increased during 2005 as compared to 2004 and 2003 because of increased volumes and higher crude oil prices. The average NYMEX crude oil price for 2005 was $56.65 per barrel versus $41.29 per barrel in 2004 and $31.08 per barrel in 2003.
- Increased field operating costs—Our continued growth, primarily from the Link acquisition and other acquisitions completed during 2004, is the principal cause of the $32.2 million increase in field operating costs to $153.4 million (including the LTIP charge) in 2005 and also the cause for increases in costs in 2004. The increased costs primarily relate to (i) payroll and benefits, (ii) emergency response and environmental remediation of pipeline releases, (iii) maintenance and (iv) utilities.
- Increased segment G&A expenses—Segment G&A expenses excluding LTIP charges were relatively flat in 2005 compared to 2004. However, expense related to our LTIP increased $6.8 million in the 2005 period as compared to the 2004 period. The increase in segment G&A expenses in 2004 is primarily related to the Link acquisition coupled with the increase in the percentage of indirect costs allocated to the pipeline operations segment in the 2004 period as our pipeline operations have grown. G&A costs also increased in 2004 compared to 2003 because of increased headcount from our growth and higher costs related to compliance activities attributable to Sarbanes-Oxley section 404 compliance. These items were partially offset by the inclusion of an LTIP charge of approximately $3.8 million in 2004 compared to $9.6 million in the 2003.

As discussed above, the increase in pipeline segment profit is largely related to our acquisition activities. We have completed a number of acquisitions during 2005, 2004 and 2003 that have impacted our results of operations. The following table summarizes the impact of recent acquisitions and expansions on volumes and revenues related to our tariff activities:

	Year Ended December 31,					
	2005		2004		2003	
	Revenues	Volumes	Revenues	Volumes	Revenues	Volumes
	(volumes in thousands of barrels per day and revenues in millions)					
Tariff activities[1][2][3]						
2005 acquisitions/expansions	$ 14.1	96	$ N/A	N/A	$ N/A	N/A
2004 acquisitions/expansions	138.2	665	115.6	525	N/A	N/A
2003 acquisitions/expansions	52.7	187	39.7	170	14.8	82
All other pipeline systems	152.6	777	144.4	717	138.5	742
Total tariff activities	$ 357.6	1,725	$ 299.7	1,412	$ 153.3	824

(1) Revenues include intersegment amounts.

(2) 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.

(3) To the extent there has been an expansion to one of our existing pipeline systems, any incremental revenues and volumes are included in the category for the period that the pipeline was acquired. For new pipeline systems that we construct, incremental revenues and volumes are included in the period the system became operational.

In 2005, average daily volumes from our tariff activities increased by approximately 22% to approximately 1.7 million barrels per day, and revenues from our tariff activities increased by approximately 19% to approximately $357.6 million. The increase is attributable to:

· Pipeline systems acquired or brought into service during 2005, which contributed approximately 96,000 barrels per day and $14.1 million of revenues during 2005. Approximately 66,000 barrels per day and $7.2 million of revenues are attributable to our recently constructed Cushing to Broome pipeline system.

· Volumes and revenues from pipeline systems acquired in 2004 increased in 2005 as compared to 2004, reflecting the following:

—An increase in 2005 as compared to 2004 of 118,000 barrels per day and $15.8 million of revenues from the pipelines acquired in the Link acquisition, reflecting the inclusion of these systems for the entire 2005 period as compared to only a portion of the 2004 period. The 2005 period also includes (i) increased revenues from our loss allowance oil resulting from higher crude oil prices and (ii) increased revenues from the Trenton pipeline system resulting from our expansion activities on that system. These increases were partially offset by the impact of a reduction in tariff rates that were voluntarily lowered to encourage third party shippers. Pipeline segment profit was reduced by approximately $12.0 million because of these market rate adjustments. As a result of these lower tariffs on barrels shipped by us in connection with our gathering and marketing activities, segment profit from GMT&S was increased by a comparable amount,

—An increase of 17,000 barrels per day and $4.4 million of revenues in 2005 as compared to 2004 from the pipelines acquired in the Capline acquisition, reflecting the inclusion of these systems for the entire 2005 period as compared to only a portion of the 2004 period, and

—An increase of 5,000 barrels per day and $2.4 million of revenues in 2005 as compared to 2004 from other businesses acquired in 2004.

· Volumes and revenues from pipeline systems acquired in 2003 increased in 2005 as compared to 2004, reflecting the following:

—An increase in 2005 as compared to 2004 of 5,000 barrels per day and $5.2 million of revenues from the pipelines acquired in the 2003 Red River acquisition, reflecting increased tariff rates on the system, partially related to the quality of crude oil shipped,

—An increase of $3.0 million of revenues related to higher realized prices on our loss allowance oil, and

—An increase of 12,000 barrels per day and $4.8 million of revenues in 2005 compared to 2004 from other businesses acquired in 2003, primarily related to higher volumes.

· Revenues from all other pipeline systems also increased in 2005, along with a slight increase in volumes. The increase in revenues is related to several items including:

—The appreciation of Canadian currency (the Canadian to U.S. dollar exchange rate appreciated to an average of 1.21 to 1 for 2005 compared to an average of 1.30 to 1 in 2004), and

—Volume increases on certain of our systems, partially related to a shift of certain minor pipeline systems from our GMT&S segment.

Average daily volumes from our tariff activities increased to approximately 1.4 million barrels per day in 2004 compared to 2003, while revenues increased to $299.7 million. The increase primarily relates to volumes and revenues from pipeline systems acquired in 2004, reflecting the following:

· The inclusion of an average of 283,000 barrels per day and $79.3 million in revenues from the pipelines acquired in the Link acquisition,

· The inclusion of an average of approximately 123,000 barrels per day and $25.9 million of revenues from the Capline pipeline system, and

· 119,000 barrels per day and $10.4 million of revenues from other 2004 acquisitions.

Several other factors impacted the increase in 2004 to a lesser extent:

· Inclusion for the full year of 2004 of several pipeline systems acquired during 2003 as compared to only a portion of the year in 2003, coupled with higher realized prices on our loss allowance oil,

· Revenues from all other pipeline systems increased in 2004, primarily related to slightly higher volumes on various systems, and

· The appreciation of Canadian currency (the Canadian to U.S. dollar exchange rate appreciated to an average of 1.30 to 1 for the year ended December 31, 2004, compared to an average of 1.40 to 1 in the year ended December 31, 2003).

Maintenance Capital

For the periods ended December 31, 2005, 2004 and 2003, maintenance capital expenditures for our pipeline segment were approximately $8.4 million, $8.3 million and $6.4 million, respectively.

Gathering, Marketing, Terminalling and Storage Operations

As of December 31, 2005, we owned approximately 39 million barrels of active above-ground crude oil terminalling and storage facilities, including a crude oil terminalling and storage facility at Cushing, Oklahoma. The Cushing Interchange is one of the largest crude oil market hubs in the United States and the designated delivery point for NYMEX crude oil futures contracts. Terminals are facilities where crude oil is transferred to or from storage or a transportation system, such as a pipeline, to another

transportation system, such as trucks or another pipeline. The operation of these facilities is called “terminalling.” Approximately 15 million barrels of our 39 million barrels of tankage is used primarily in our GMT&S segment and the balance is used in our Pipeline segment.

On a stand-alone basis, segment profit from terminalling and storage activities is dependent on the throughput of volumes, the volume of crude oil stored and the level of fees generated from our terminalling and storage services. Our terminalling and storage activities are integrated with our gathering and marketing activities and thus the level of tankage that we allocate for our arbitrage activities (and therefore not available for lease to third parties) varies throughout crude oil price cycles. This integration enables us to use our storage tanks in an effort to counter-cyclically balance and hedge our gathering and marketing activities. In a contango market (when oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (when oil prices for future deliveries are lower than for current deliveries), we use less storage capacity, but increased marketing margins (premiums for prompt delivery resulting from high demand) provide an offset to this reduced cash flow. In addition, we supplement the counter-cyclical balance of our asset base with derivative hedging activities. We believe that this combination of our terminalling and storage activities, gathering and marketing activities and our hedging activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flows. We also believe that this balance enables us to protect against downside risk while at the same time providing us with upside opportunities in volatile market conditions.

Our revenues from gathering and marketing activities reflect the sale of gathered and bulk-purchased crude oil and LPG volumes, plus 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. As an example of the potential lack of correlation between changes in revenues and changes in segment profit, our revenues increased approximately 50% in 2005 compared to 2004, while our segment profit more than doubled in the same period. These increases in segment profit are discussed further below. 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 lease gathered volumes and LPG sales volumes. However, certain market conditions create opportunities that may significantly impact segment profit. Although we believe that the combination of our lease gathering business and our storage assets provides a counter-cyclical balance that provides stability in our margins, these margins are not fixed and may vary from period to period.

Revenues from our GMT&S operations were approximately $30.2 billion, $20.2 billion and $12.0 billion for the years ended December 31, 2005, 2004 and 2003, respectively. The increase in revenues for 2005 as compared to 2004 and 2003 was primarily because of higher crude oil prices. The average NYMEX price for crude oil was $56.65, $41.29 and $31.08 per barrel for the years ended December 31, 2005, 2004 and 2003, respectively.

In order to evaluate the performance of this segment, management focuses on the following metrics: (i) segment profit, (ii) crude oil lease gathered volumes and LPG sales volumes and (iii) segment profit per barrel calculated on these volumes. The following table sets forth our operating results from our GMT&S segment for the comparative periods indicated:

	December 31, 2005	December 31, 2004	December 31, 2003
	(in millions, except per barrel amounts)		
Operating Results[1]			
Revenues[2] [3]	$ 30,186.6	$ 20,223.5	$ 11,985.6
Purchases and related costs[4][5]	(29,830.6)	(19,992.8)	(11,799.8)
Field operating costs (excluding LTIP charge)	(117.0)	(97.5)	(73.3)
LTIP charge—operations	(2.1)	(0.8)	(4.3)
Segment G&A expenses (excluding LTIP charge)[6]	(40.6)	(37.7)	(31.6)
LTIP charge—general and administrative[6]	(12.4)	(3.2)	(13.5)
Segment profit[3]	$ 183.9	$ 91.5	$ 63.1
SFAS 133 mark-to-market adjustment[3]	$ (18.9)	$ 1.0	$ 0.4
Maintenance capital	$ 5.6	$ 3.0	$ 1.2
Segment profit per barrel[7]	$ 0.77	$ 0.39	$ 0.36
Average Daily Volumes			
(thousands of barrels per day)[8]			
Crude oil lease gathering	610	589	437
LPG sales	56	48	38

(1) Revenues and purchases and related costs include intersegment amounts.

(2) Includes revenues associated with buy/sell arrangements of $16,077.8 million, $11,247.0 million and $6,124.9 million for the years ended December 31, 2005, 2004 and 2003, respectively. Volumes associated with these arrangements were approximately 744,000, 790,000 and 545,000 barrels per day for the years ended December 31, 2005, 2004 and 2003, 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 $15,910.3 million, $11,137.7 million and $5,967.2 million for the years ended December 31, 2005, 2004 and 2003, respectively. Volumes associated with these arrangements were approximately 744,000, 790,000 and 545,000 barrels per day for the years ended December 31, 2005, 2004 and 2003, 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.

(5) Purchases and related costs include interest expense on contango inventory purchases of $23.7 million, $2.0 million and $1.0 million for the years ended December 31, 2005, 2004 and 2003, respectively.

(6) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each year.

(7) Calculated based on crude oil lease gathered volumes and LPG sales volumes.

(8) 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.

Segment profit in 2005 increased significantly over 2004. The increase was primarily related to very favorable market conditions and successful execution of risk management strategies coupled with increased volumes and synergies realized from businesses acquired in the last two years.

The primary factors affecting current period results were:

· Favorable market conditions—These favorable market conditions include a shift in the market structure from a backwardated market with a price differential of as much as $1.14 per barrel in late 2004 to a prolonged and pronounced contango market with a price differential of as much as $1.91 in 2005. The contango market averaged approximately $0.48, $1.22, $0.69 and $0.46 in each quarter of 2005, respectively. Although we are normally adversely impacted by the initial transition from a backwardated market to a contango market, the market remained in contango throughout much of 2005 and we have been able to adjust our purchases at the wellhead to both maintain our margins and remain competitive in the gathering and marketing business. In addition, we have been able to use a portion of our tankage in our terminalling and storage business to capture a significant level of profits from contango-related strategies. The volatile market allowed us to utilize our hedging activities to optimize and enhance the margins of both our gathering and marketing assets and our terminalling and storage assets at different times during the year. Increased receipts of foreign crude oil movements at our facilities also positively impacted our results.

· Increased tankage used in our GMT&S operations—The positive impact of the favorable market conditions discussed above was further enhanced by the increase in the average amount of tankage used in our GMT&S operations to approximately 13.3 million barrels during 2005 as compared to an average of 12.7 million barrels in 2004.

· Decreased transportation costs—Lower tariffs on barrels shipped by us on certain pipelines acquired in the Link acquisition reduced purchases and related costs by approximately $12.0 million for the year ended December 31, 2005. Segment profit for our Pipeline segment was decreased by a comparable amount.

· Increased field operating costs—The increased costs primarily related to payroll and benefits and to higher fuel costs. These increases are the result of our growth, primarily from acquisitions, and higher fuel prices during 2005 as compared to 2004.

We recognized a mark-to-market adjustment of $18.9 million net loss in 2005 pursuant to SFAS 133 compared to a net gain of $1.0 million in the 2004. The $18.9 million adjustment was largely attributable to U.S. commodities. The primary components of the adjustment included:

· A decrease in the mark-to-market of approximately $19.9 million resulting from the change in fair value for option and futures contracts that serve to mitigate risk associated with our lease gathering and tankage business exposures. Although these derivatives do not qualify for hedge accounting, their purpose is to mitigate risk associated with our physical assets in our storage and terminalling activities and contractual arrangements in our lease gathering activities. A portion of the decrease in fair value during the current period relates to the settlement of mark-to-market gains from the previous period. Total settlements related to these strategies during 2005 were revenues of $19.4 million. The $19.9 million further breaks down as follows:

—The amount of the decrease in the mark-to-market fair value for option contracts was approximately $7.4 million. Because our option activity often involves option sales, these do not receive hedge accounting treatment. Some of the fluctuations in value for those option contracts are due to time to expiry and volatility in the marketplace. Because these strategies are executed with a long-term risk management goal and the intent to take delivery and utilize the tankage assets to store physical commodity if so needed, the impact on forward positions due to these fluctuations is not indicative of true anticipated economic results.

—The amount of the decrease in the mark-to-market fair value for futures contracts was approximately $12.5 million. The majority of this decrease was due to reduced backwardation during that time frame. In general, revenue from storing crude oil is reduced in a backwardated market (when oil prices for future deliveries are lower than for current deliveries) as there is less incentive to store crude oil from month-to-month. We enter into derivative contracts that will offset the reduction in revenue by generating offsetting gains in a backwardated market structure. Because the tankage arrangements will not necessarily result in physical delivery, they are not eligible for hedge accounting treatment under SFAS 133. A reduction in backwardation results in forward losses in our risk management strategies offset by stronger storage revenues. However, owning the assets and having the ability to take delivery allows us to limit exposures to the cost of storage.

• An increase in the mark-to-market of $1.1 million primarily related to the change in fair value of certain derivative instruments used to minimize the risk of unfavorable changes in exchange rates. A portion of the increase in fair value during the current period relates to the settlement of mark-to-market losses from the previous period. Total settlements related to these derivatives during 2005 were $0.7 million.

Segment profit per barrel (calculated based on our lease gathered crude oil and LPG volumes) was $0.77, $0.39 and $0.36 per barrel for the years ended December 31, 2005, 2004 and 2003, respectively. As discussed above, our current period results were strongly impacted by favorable market conditions. We are not able to predict with any reasonable level of accuracy whether market conditions will remain as favorable as we have recently experienced, and operating results may not be indicative of sustainable performance.

Maintenance capital

For the periods ended December 31, 2005, 2004 and 2003, maintenance capital expenditures were approximately $5.6 million, $3.0 million, and $1.2 million, respectively, for our gathering, marketing, terminalling and storage operations segment. The year over year increases are related to our growth.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense was $83.5 million for the year ended December 31, 2005, compared to $68.7 million and $46.2 million for the years ended December 31, 2004 and 2003, respectively. The increase in 2005 relates primarily to (i) an increased amount of depreciable assets resulting from our acquisition activities and capital projects, (ii) accelerated depreciation and amortization for tanks that we plan to take out of service by 2009, and (iii) a non-cash loss related to sales of assets. The increase in 2004 relates primarily to the assets from our 2004 acquisitions and our various 2003 acquisitions being included for the full year versus only a part of the year in 2003. In addition, 2004 includes approximately $4.2 million of depreciation of trucks and trailers under capital leases and an impairment charge of approximately $2.0 million associated with taking our pipeline system in the Illinois Basin out of service. Amortization of debt issue costs was $2.8 million in 2005, $2.5 million in 2004, and $3.8 million in 2003.

Interest Expense

Interest expense was $59.4 million for the year ended December 31, 2005, compared to $46.7 million and $35.2 million for the years ended December 31, 2004 and 2003, respectively. Interest expense is primarily impacted by:

- our average debt balances;

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

The following table summarizes selected components of our average debt balances:

	For the year ended December 31,		
	2005	2004	2003
	(in millions)		
Fixed rate senior notes[1]	$ 891	$ 586	$ 214
Borrowings under our revolving credit facilities[2]	135	274	311
Total	$ 1,026	$ 860	$ 525

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

(2) Excludes borrowings under our senior secured hedged inventory facility and other contango inventory-related borrowings.

During 2005, we issued $150 million of 10-year senior unsecured notes. During the third quarter of 2004, we issued $175 million of five-year senior unsecured notes and $175 million of 12-year senior unsecured notes. These issuances resulted in an increase in the average amount of longer term and higher cost fixed-rate debt outstanding in 2005 to approximately 87% as compared to approximately 68% in 2004 and 41% in 2003. During 2005, 2004 and 2003, the average three month LIBOR rate was 3.6%, 1.6%, and 1.2%, respectively. The overall higher average debt balances in 2005 and 2004 were primarily related to the portion of our acquisitions that were not financed with equity, coupled with borrowings related to other capital projects. Our weighted average interest rate, excluding commitment and other fees, was approximately 5.6% in 2005, compared to 5.0% and 6.0% in 2004 and 2003, respectively. The net impact of the items discussed above was an increase in interest expense in 2005 of approximately $12.7 million to a total of $59.4 million.

The higher average debt balance in 2004 as compared to 2003 resulted in additional interest expense of approximately $16.8 million, while at the same time our commitment and other fees decreased by approximately $0.4 million. Our weighted average interest rate, excluding commitment and other fees, was approximately 5.0% for 2004 compared to 6.0% for 2003. The lower weighted average rate decreased interest expense by approximately $4.9 million in 2004 compared to 2003.

Interest costs attributable to borrowings for inventory stored in a contango market are included in purchases and related costs in our GMT&S 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 $23.7 million, $2.0 million and $1.0 million for the year ended December 31, 2005, 2004 and 2003, respectively.

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 by us of transportation, gathering, terminalling or storage assets and related midstream businesses. These acquisition efforts often involve assets which, if acquired, could have a material effect on our financial condition and results of operations. In an effort to prudently and economically leverage our asset base, knowledge base and skill sets, management has also expanded its efforts to encompass midstream businesses outside of the scope of our current operations, but with respect to which these resources effectively can be applied. We are presently engaged in discussions and

negotiations with various parties regarding the acquisition of assets and businesses described above, but we can give no assurance that our current or future acquisition efforts will be successful or that any such acquisition will be completed on terms considered favorable to us.

Pipeline Integrity and Storage Tank Testing Compliance. Although we believe our short-term estimates of costs under the pipeline integrity management rules and API 653 (and similar Canadian regulations) are reasonable, a high degree of uncertainty exists with respect to estimating such costs, as we continue to test existing assets and as we acquire additional assets.

The DOT is currently considering expanding the scope of its pipeline regulation to include certain gathering pipeline systems that are not currently subject to regulation. This expanded scope could include the establishment of additional pipeline integrity management programs for these newly regulated pipelines. We do not currently know what, if any, impact this will have on our operating expenses. However, we cannot assure you that future costs related to the potential programs will not be material.

During 2006, we are expanding an internal review process started in 2004 in which we are reviewing various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management rule. The purpose of this process is to review the surrounding environment, condition and operating history of these pipelines and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, we may be required (as a result of additional DOT regulation) or we may elect (as a result of our own initiatives) to spend substantial sums to ensure the integrity of and upgrade our pipeline systems to maintain environmental compliance and, in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines. We cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures for environmental compliance.

Longer-Term Outlook. Our longer-term outlook, spanning a period of five or more years, 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.
- Aggressive practices in the U.S. to maintain working crude oil inventory levels below historical levels despite rising demand in North America.
- 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 capacity or, alternatively, will result in a reduction of existing storage capacity by 2009.
- 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 reduced inventories and tight supply and demand balances, even relatively minor supply disruptions can cause significant price swings, which were evident in 2005. 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 are also regularly evaluating midstream businesses that are complementary to our existing businesses and that possess attractive long-term growth prospects. Through PAA/Vulcan's acquisition of ECI in 2005, the Partnership entered the natural gas storage business. 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 that strategically located natural gas storage facilities will become increasingly important in supporting the reliability of gas service needs in the United States. Rising demand for natural gas is outpacing domestic natural gas production, creating an increased need for imported natural gas. A continuation of this trend will result in increased natural gas imports from Canada and the Gulf of Mexico, and LNG imports. 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.

Liquidity and Capital Resources

The Partnership has a defined financial growth strategy that states how we intend to finance our growth and sets forth targeted credit metrics. We have also established a targeted credit rating. See Items 1 and 2. "Business and Properties—Financial Strategy."

Cash generated from operations and our credit facilities are our primary sources of liquidity. At December 31, 2005, we had working capital of approximately $11.9 million, approximately $789.1 million of availability under our committed revolving credit facilities and approximately $580.7 million of availability under our uncommitted hedged inventory facility. Usage of the credit facilities is subject to compliance with covenants. We believe we are currently in compliance with all covenants.

Cash generated from operations

The primary drivers of cash generated from our operations are (i) the collection of amounts related to the sale of crude oil and LPG and the transportation of crude oil for a fee and (ii) the payment of amounts related to the purchase of crude oil and LPG 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 in the months that we store inventory because of contango market conditions or in months in which we increase linefill. The storage of crude oil in periods of a contango market can have a material impact on our cash flows from operating activities for the period in which we pay for and store the crude oil and the subsequent period in which we receive proceeds from the sale of the crude oil. When we store the crude oil, we borrow under our credit facilities to pay for the crude oil so the impact on operating cash flow is negative. 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, the level of LPG inventory stored at period end affects our cash flow from operating activities.

Our cash flow from operations was $24.1 million in 2005 and reflects cash generated by our recurring operations offset primarily by an increase in inventory of approximately $412 millionoffset by a net decrease in other components of working capital. The net decrease is primarily related to changes in accounts receivable and payables related to the purchase and sale of crude oil and NYMEX margin deposits.

Cash flow from operating activities was $104.0 million in 2004 and reflects cash generated by our recurring operations that was offset negatively by several factors totaling approximately $100 million. The primary item was a net increase in hedged crude oil and LPG inventory and linefill in third party assets that was financed with borrowings under our credit facilities (approximately $75 million net). Cash flow from operations was also negatively impacted by a decrease of approximately $20 million in prepayments received from counterparties to mitigate credit risk. Our positive cash flow from operating activities for

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2003 resulted from cash generated by our recurring operations. In addition, cash flow from operating activities was positively impacted by approximately $74 million related to proceeds received in 2003 from the sale of 2002 hedged crude oil inventory and negatively impacted by approximately $100 million related to inventory stored at the end of 2003. The proceeds from the sale of the 2003 stored crude oil were received in the first quarter of 2004. In 2003, we also received approximately $23 million of additional prepayments over the 2002 balance from counterparties to mitigate our credit risk, and paid approximately $6.2 million to terminate an interest rate hedge in conjunction with a change in our capital structure.

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 billion of debt or equity securities. At December 31, 2005, we have approximately $1.8 billion of unissued securities remaining available under this registration statement.

Cash provided by financing activities was $270.6 million, $554.5 million and $157.2 million for each of the last three years, respectively. Our financing activities primarily relate to funding (i) acquisitions, (ii) internal capital projects and (iii) 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 under our credit facilities.

Equity Offerings. During the last three years we completed several equity offerings as summarized in the table below. Certain of these offerings involved related parties. See Note 8 to our Consolidated Financial Statements:

2005		2004		2003	
Units	Net Proceeds[(1)]	Units	Net Proceeds[(1)]	Units	Net Proceeds[(1)]
		(in millions, except units)			
5,854,000	$ 241.9	4,968,000	$ 160.9	2,840,800	$ 88.4
575,000	22.3	3,245,700	100.9	3,250,000	98.0
	$ 264.2		$ 261.8	2,645,000	63.9
					$ 250.3

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

Senior Notes and Credit Facilities. During the three years ended December 31, 2005 we completed the sale of senior unsecured notes as summarized in the table below.

Year	Description	Face Value	Net Proceeds[(1)]
		(in millions)	
2005	5.25% Senior Notes issued at 99.5% of face value	$ 150	$ 149.3
2004	4.75% Senior Notes issued at 99.6% of face value	$175	$174.2
	5.88% Senior Notes issued at 99.3% of face value	$175	$173.9
2003	5.625% Senior notes isued at 99.7% of face value	$ 250	$ 249.3

(1) Face value of notes less the applicable discount.

During the year ended December 31, 2005, we had net working capital and short-term letter of credit and hedged inventory borrowings of approximately $206.1 million. These borrowings are used primarily for purchases of crude oil inventory that was stored. See "—Cash generated from operations." During 2005, we also had net repayments on our long-term revolving credit facility of approximately $143.7 million resulting from cash generated from our operations and other financing activities. During 2004, we had net borrowings under our long-term and short-term revolving credit facilities of approximately $107.7 million and during 2003 we had net repayments of $215.4 million. For further discussion related to our credit facilities and long-term debt, see "—Credit Facilities and Long-term Debt."

Capital Expenditures and Distributions Paid to Unitholders and General Partners

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, capital expenditures for internal growth projects and distributions paid to our unitholders and general partners. 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.

2006 Capital Expansion Projects. We expect to invest approximately $230 million on internal growth projects during 2006. We also expect maintenance capital costs to be approximately $23 million. Our 2006 projects include the following projects with the estimated cost for the entire year (in millions):

Projects	2006
St. James, Louisiana storage facility	$ 60
Spraberry System expansion	20
High Prairie truck and rail terminals	31
Kerrobert tankage and pumps	35
Midale truck terminal	11
Truck trailers	11
Wichita Falls tankage	9
Other Projects	53
Subtotal	230
Maintenance capital	23
Total	$ 253

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. However, we are subject to business and operational risks that could adversely affect our cash flow. A material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

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					
	Common	Subordinated	GP			Distribution
Year	Units	Units[1]	Incentive	2%	Total	per LP unit
2005	$ 178.4	$ —	$ 15.0	$ 3.6	$ 197.0	$ 2.58
2004	$ 142.9	$ 4.2	$ 8.3	$ 3.0	$ 158.4	$ 2.30
2003	$ 92.7	$ 21.9	$ 4.9	$ 2.3	$ 121.8	$ 2.19

(1) The subordinated units were converted to common units in 2003 and 2004.

Credit Facilities and Long-term Debt

In November 2005, we amended our senior unsecured credit facility to increase the aggregate capacity to $1 billion and the sub-facility for Canadian borrowings to $400 million. The amended facility can be expanded to $1.5 billion, subject to additional lender commitments, and has a final maturity of November 2010. Additionally, in the second quarter of 2005, we amended our senior secured hedged inventory facility to increase the capacity under the facility from $425 million to $800 million. In November 2005, we extended the maturity of the senior secured hedged inventory facility to November 2006.

We also have five issues of senior debt outstanding that total $950 million, excluding premium or discount, and range in size from $150 million to $250 million and mature at various dates through 2016. The $950 million senior debt includes $150 million principal long-term debt issued in 2005, which matures in 2015. See Note 4 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 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 5.25 to 1.0 on all 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 10 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, 2005.

	Total	2006	2007	2008	2009	2010	2011 and Thereafter
				(in millions)			
Long-term debt and interest payments[1]	$ 1,384.7	$ 57.0	$ 57.0	$ 57.0	$ 228.7	$ 47.7	$ 937.3
Leases[2]	114.0	19.8	16.7	12.4	11.5	9.6	44.0
Capital expenditure obligations	5.0	5.0	—	—	—	—	—
Other long-term liabilities[3]	42.7	4.5	30.5	2.2	0.6	0.2	4.7
Subtotal	1,546.4	86.3	104.2	71.6	240.8	57.5	986.0
Crude oil and LPG purchases[4]	2,790.6	2,065.7	575.1	138.2	3.9	2.2	5.5
Total	$ 4,337.0	$ 2,152.0	$ 679.3	$ 209.8	$ 244.7	$ 59.7	$ 991.5

(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, 2005 (this amount is included in the amounts above), 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 trucks used in our gathering activities.

(3) Excludes approximately $6.5 million non-current liability related to SFAS 133 which are 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, 2005, we had outstanding letters of credit of approximately $55.5 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 (i) certain projects specified at the time PAA/Vulcan acquired ECI and (ii) unspecified future capital needs up to an aggregate of $20 million.

For certain other specified projects, Vulcan Gas Storage has the right, but not the obligation, to participate for 50% of the cost. For any other project (or a project in which Vulcan Gas Storage declines to exercise its right to participate), we have the right to make additional capital contributions to fund 100% of the project. Such contributions would increase our interest in PAA/Vulcan and dilute Vulcan Gas Storage's interest. If at any time our interest in PAA/Vulcan exceeds 70%, Vulcan Gas Storage would have the right, but not the obligation, to make capital contributions proportionate to its ownership interest at the time. See Note 8 to our Consolidated Financial Statements.

Distributions. We plan to 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 cash and cash equivalents on hand at the end of the quarter less reserves established in the discretion of our general partner for future requirements. On February 14, 2006, we paid a cash distribution of $0.6875 per unit on all outstanding units. The total distribution paid was approximately $57.3 million, with approximately $50.7 million paid to our common unitholders and approximately $6.6 million paid to our general partner for its general partner interest ($1.0 million) and incentive distribution interest ($5.6 million).

Our general partner is entitled to 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, to 15% of amounts we distribute in excess of $0.450 per limited partner unit, 25% of amounts we distribute in excess of $0.495 per limited partner unit and 50% of amounts we distribute in excess of $0.675 per limited partner unit. In 2005, we paid $14.9 million in incentive distributions to our general partner. See Item 13. "Certain Relationships and Related Transactions—Our General Partner."

Off-Balance Sheet Arrangements

We have invested in an entity, PAA/Vulcan Gas Storage, LLC, which is not consolidated in our financial statements. In conjunction with this investment, from time to time we may elect to provide financial and performance guarantees or other forms of credit support. See Note 8 to our Consolidated Financial Statements for more information concerning our obligations as they relate to this investment.

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

We are exposed to various market risks, including volatility in (i) crude oil 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, IPE 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 and LPG in storage, and expected purchases and sales of these commodities. The derivative instruments utilized consist primarily of futures and option contracts traded on the NYMEX, IPE and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies. Our policy is to purchase only crude oil for which we have a market, and to structure our sales contracts so that crude oil price fluctuations do not materially affect the segment profit we receive. Except for the controlled trading program discussed below, we do not acquire and hold crude oil futures contracts or other derivative products for the purpose of speculating on crude oil 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.

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 will receive mark-to-market treatment in current earnings, and result in greater potential for earnings volatility. This accounting treatment is discussed further under Note 2 to our Consolidated Financial Statements.

All of our open commodity price risk derivatives at December 31, 2005 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 decrease are shown in the table below:

	Fair Value (in millions)	Effect of 10% Price Decrease
Crude oil:		
Futures contracts	$ (16.0)	$ (41.5)
Swaps and options contracts	$ (17.5)	$ (16.8)
LPG:		
Swaps and options contracts	$ 10.2	$ 8.8

The fair values of the futures contracts are based on quoted market prices obtained from the NYMEX. The fair value of the swaps and option contracts are 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 is 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 decrease 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 swaps and collars to hedge interest obligations on specific debt issuances, including anticipated debt issuances. We had no interest rate hedging instruments outstanding as of December 31, 2005. The table below presents principal payments and the related weighted average interest rates by expected maturity dates for variable rate debt outstanding at December 31, 2005. All of our senior notes are fixed rate notes and their interest rates are not subject to market risk. Our variable rate debt bears interest at LIBOR, prime or the bankers acceptance rate plus the applicable margin. The average interest rates presented below are based upon rates in effect at December 31, 2005. 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.

	Expected Year of Maturity 2006	2007	2008	2009	2010	Thereafter	Total
	(dollars in millions)						
Liabilities:							
Short-term debt—variable rate	$ 374.7	$ —	$ —	$ —	$ —	$ —	$ 374.7
Average interest rate	4.9%	—	—	—	—	—	4.9%
Long-term debt—variable rate	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Average interest rate	—	—	—	—	—	—	—

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 include forward exchange contracts and cross currency swaps. Neither the forward exchange contracts nor the cross currency swaps qualify for hedge accounting in accordance with SFAS 133.

At December 31, 2005, we had forward exchange contracts that allow us to exchange $2.0 million Canadian dollars for $1.5 million U.S. dollars, quarterly (based on a Canadian dollar to U.S. dollar exchange rate of 1.32 to 1).

In addition, at December 31, 2005, we also had cross currency swap contracts for an aggregate notional principal amount of $19.0 million, effectively converting this amount of our U.S. dollar denominated debt to $29.4 million of Canadian dollar debt (based on a Canadian dollar to U.S. dollar exchange rate of 1.55 to 1). The notional principal amount has a final maturity in May 2006 of $19.0 million U.S. At December 31, 2005, none of our long-term debt was denominated in Canadian dollars. All of these financial instruments are placed with what we believe to be large, creditworthy financial institutions.

We estimate the fair value of these instruments based on current termination values. The table shown below summarizes the fair value of our foreign currency hedges by year of maturity (in millions):

	Year of Maturity 2006	2007	2008	2009	2010	Total
Forward exchange contracts	$ (0.8)	$ —	$ —	$ —	$ —	$ (0.8)
Cross currency swaps	(6.4)	—	—	—	—	(6.4)
Total	$ (7.2)	$ —	$ —	$ —	$ —	$ (7.2)

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

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

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 December 31, 2005, 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 during preparation for our assertion on internal control over financial reporting, 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, 2005. See Management's Report on Internal Control Over Financial Reporting on page F-2.

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

There was no information required to be disclosed in a report on Form 8-K during the fourth quarter of 2005 that has not previously been reported.

PART III

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

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 the general partner of our general partner, 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). References to our general partner, unless the context otherwise requires, include 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 and LPG 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 the 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 partnership agreement provides that the general partner will manage and operate us and that, unlike holders of common stock in a corporation, unitholders 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. Specifically, our partnership agreement defines "Board of Directors" to 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 Second 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% and the ownership set forth under 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 with respect to 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, to unilaterally 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 agreement. The time between notice and termination depends on the circumstances, but would never be longer than one year. Upon any breach or termination by Vulcan Energy of, or notice of termination under, the voting agreement, employment agreement waivers obtained in connection with the August 2005 change of control would

terminate. See Item 11. "Executive Compensation—Employment Contracts and Termination of Employment and Change-in-Control Arrangements."

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 Plains AAP, L.P. 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 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 Tim Moore, General Counsel and Secretary or Sharon Spurlin, 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.

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. However, we are 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, a director must be determined to have 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 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 401 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 2005, the amount paid to LEH by Plains Marketing was approximately $1.6 million (net of severance taxes). The Board has determined that the transactions with LEH are not material and do not compromise Mr. Goyanes' independence.

Mr. J. Taft Symonds, a member of our audit committee, is a director and the non-executive Chairman of the Board of Tetra Technologies, Inc. ("Tetra"). A subsidiary of Tetra owns crude oil producing properties, from some of which Plains Marketing buys the production. We paid approximately $8.9 million (net of severance taxes) to the Tetra subsidiary in 2005. Mr. Symonds was not and is not an officer of

Tetra, and does not participate in operational decision making, including decisions concerning selection of crude oil purchasers or entering into sales or marketing arrangements. The Board has determined that the transactions with Tetra are not material and do not compromise Mr. Symonds' independence.

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

We have a compensation committee that reviews and makes recommendations regarding the compensation for the executive officers and administers our equity compensation plans for officers and key employees. We also have a governance committee that periodically reviews our governance guidelines. 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. The members of our audit committee and other committees are indicated in the table below under "—Directors and Executive Officers."

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 Corporate 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 pursuant to Item 5.05 thereof. 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 and opinions on management's assessment and on the effectiveness of the Partnership's internal control over financial reporting. 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, 2005 for filing with the SEC.

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

Directors and Executive Officers

The following table sets forth certain information with respect to the executive officers and members of the Board of Directors of our general partner. Directors are elected annually and all executive officers are appointed by the Board of Directors to serve until their resignation, death or removal. There is no family relationship between any executive officer or director. Certain owners of our general partner each have the right to separately designate a member of our board. Such designees are indicated in the footnote to the following table.

Name	Age (as of 12/31/05)	Position with Our General Partner
Greg L. Armstrong(1)	47	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis	48	President and Chief Operating Officer
Phillip D. Kramer	49	Executive Vice President and Chief Financial Officer
George R. Coiner	55	Senior Group Vice President
W. David Duckett	50	President—PMC (Nova Scotia) Company
Mark F. Shires	48	Senior Vice President—Operations
Alfred A. Lindseth	36	Senior Vice President—Technology, Process & Risk Management
Lawrence J. Dreyfuss	51	Vice President, Associate General Counsel and Assistant Secretary; Vice President, General Counsel and Secretary of PMC (Nova Scotia) Company (the general partner of Plains Marketing Canada, L.P.)
James B. Fryfogle	54	Vice President—Refinery Supply
Jim G. Hester	46	Vice President—Acquisitions
Tim Moore	48	Vice President, General Counsel and Secretary
Daniel J. Nerbonne	48	Vice President—Engineering
John F. Russell	57	Vice President—Pipeline Operations
Al Swanson	41	Vice President—Finance and Treasurer
Tina L. Val	36	Vice President—Accounting and Chief Accounting Officer
Troy E. Valenzuela	44	Vice President—Environmental, Health and Safety
John P. vonBerg	51	Vice President—Trading
David N. Capobianco(1)	36	Director and Member of Compensation* Committee
Everardo Goyanes	61	Director and Member of Audit* Committee
Gary R. Petersen(1)	59	Director and Member of Compensation Committee
Robert V. Sinnott(1)	56	Director and Member of Compensation Committee
Arthur L. Smith	53	Director and Member of Audit and Governance* Committees
J. Taft Symonds	66	Director and Member of Audit and Governance Committees

* Indicates chairman of committee.

(1) The GP LLC Agreement specifies that the Chief Executive Officer of the general partner will be a member of the board of directors. The LLC Agreement also provides that certain of the owners of our general partner have the right to designate a member of our board of directors. Mr. Capobianco has been designated by Vulcan Energy Corporation, of which he is Chairman of the Board. Vulcan Energy Corporation has the right at any time to designate an additional director. Mr. Petersen has been designated by E-Holdings III, L.P., an affiliate of EnCap Investments L.P., of which he is Senior Managing Director. Mr. Sinnott has been designated 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. 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.

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.

George R. Coiner has served as Senior Group Vice President since February 2004 and as Senior Vice President from our formation in 1998 to February 2004. In addition, he was Vice President of Plains Marketing & Transportation Inc. from November 1995 until our formation. Prior to joining Plains Marketing & Transportation Inc., he was Senior Vice President, Marketing with Scurlock Permian LLC.

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.

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.

Lawrence J. Dreyfuss has served as Vice President, Associate General Counsel and Assistant Secretary of our general partner since February 2004 and as 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.

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.

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.

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.

John F. Russell has served as Vice President—Pipeline Operations since July 2004. 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.

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.

Al Swanson has served as Vice President—Finance and Treasurer since August 2005, 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.

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 of Trading since May 2003 and Director of these activities since 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 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, an affiliate 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 Chairman of the board of Vulcan Resources Florida, and is a director of PAA/Vulcan and ICAT Holdings. 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 Oil Corporation from 1983 to 1987. 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 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 National Security Agency.

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. 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 Chairman and CEO of John S. Herold, Inc. (a petroleum research and consulting firm), a position he has held since 1984. 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 boards of Kuwait Energy (a private oil and gas exploration and production firm), 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 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 2005, except as follows: Messrs. Shires and Lindseth each inadvertently filed a late Form 4 in connection with the exercise of performance options on November 18, 2005. The Forms 4 were filed on November 28, 2005.

Canadian Officers

The following table sets forth certain information with respect to officers of the general partner of our Canadian operating partnership.

Name	Age	Position with Our Canadian General Partner

	(as of 12/31/05)	
D. Mark Alenius	46	Vice President and Chief Financial Officer of PMC (Nova Scotia) Company
Ralph R. Cross	50	Vice President—Business Development and Transportation Services of PMC (Nova Scotia) Company
Stephen L. Bart	45	Vice President—Operations of PMC (Nova Scotia) Company
M.D. (Mike) Hallahan	45	Vice President—Crude Oil of PMC (Nova Scotia) Company
Richard (Rick) Henson	51	Vice President—Corporate Services of PMC (Nova Scotia) Company
Ron F. Wunder	37	Vice President—LPG of PMC (Nova Scotia) Company

D. Mark Alenius has served as Vice President and Chief Financial Officer of PMC (Nova Scotia) Company since November 2002. In addition, Mr. Alenius was Managing Director, Finance of PMC (Nova Scotia) Company from July 2001 to November 2002. Mr. Alenius was previously with CANPET Energy Group Inc. where he served as Vice President, Finance, Secretary and Treasurer, and was a member of the Board of Directors. Mr. Alenius joined CANPET in February 2000. Prior to joining CANPET Energy, Mr. Alenius briefly served as Chief Financial Officer of Bromley-Marr ECOS Inc., a manufacturing and processing company, from January to July 1999. Mr. Alenius was previously with Koch Industries, Inc.'s Canadian group of businesses, where he served in various capacities, including most recently as Vice-President, Finance and Chief Financial Officer of Koch Pipelines Canada, Ltd.

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.

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.

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 General Manager, Facilities.

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.

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.

Item 11. *Executive Compensation*

Summary Compensation Table

The following table sets forth certain compensation information for our Chief Executive Officer and the four other most highly compensated executive officers in 2005 (the "Named Executive Officers"). We reimburse our general partner and its affiliates for expenses incurred on our behalf, including the costs of officer compensation. In addition to the amounts presented below, the Named Executive Officers have also received certain equity-based awards from our general partner, which awards (other than awards under the Long-Term Incentive Plans) are not subject to reimbursement by us. See "—Long-Term Incentive Plans" and Item 13. "Certain Relationships and Related Transactions—Transactions with Related Parties."

Name and Principal Position	Year	Annual Compensation: Salary	Bonus	Other Annual Compensation[1]	Long-Term Compensation: LTIP Payout[2]	All Other Compensation
Greg L. Armstrong	2005	$ 371,250	$3,000,000	$ 149,625	$ 701,575	$ 14,930[3]
Chairman and CEO	2004	330,000	1,800,000	—	1,692,600	13,930[3]
	2003	330,000	1,000,000	—	—	12,930[3]
Harry N. Pefanis	2005	$ 294,583	$2,750,000	$ 99,750	$ 100,225	$ 14,930[3]
President and COO	2004	235,000	1,500,000	—	1,674,600	13,875[3]
	2003	235,000	800,000	—	452,400	12,875[3]
George R. Coiner	2005	$ 245,833	$2,645,600[4]	$ 50,500	$ 375,844	$ 14,930[3]
Senior Group Vice	2004	200,000	1,061,000[4]	—	1,643,138	13,730[3]
President	2003	200,000	719,600[4]	—	226,200	12,730[3]
W. David Duckett[5]	2005	$ 234,601	$ 1,680,998[6]	$ 48,338	$ —	$ 29,823[7]
President—PMC	2004	204,161	933,505[6]	—	—	26,541[7]
(Nova Scotia) Company	2003	190,658	724,883[6]	—	—	25,512[7]
John P. vonBerg	2005	$ 200,000	$2,345,400[8]	$ 25,250	$ 125,281	$ 14,744[3]
Vice President—Trading	2004	200,000	837,800[8]	—	302,250	13,744[3]
	2003	200,000	623,300[8]	—	—	12,744[3]

(1) Includes cash payments pursuant to distribution equivalent rights associated with phantom units granted under the 2005 LTIP. See "—Long-Term Incentive Plans—2005 Long-Term Incentive Plan." Does not include the value of perquisites and other personal benefits because they do not exceed for any individual $50,000 in the aggregate.

(2) Amounts presented represent the aggregate value of vested phantom units determined as of their vesting date. See "—Long-Term Incentive Plans—1998 Long-Term Incentive Plan."

(3) Our general partner matches 100% of employees' contributions to its 401(k) Plan in cash, subject to certain limitations in the plan. Includes $14,000, $13,000 and $12,000 in such contributions for 2005, 2004 and 2003, respectively. The remaining amount represents premium payments on behalf of the Named Executive Officer for group term life insurance.

(4) Includes quarterly bonuses aggregating $1,395,600, $561,000 and $469,600, and an annual bonus of $1,250,000, $500,000 and $250,000 for 2005, 2004 and 2003, respectively. The annual bonuses are payable 60% at the time of award and 20% in each of the two succeeding years. For the quarterly bonuses, Mr. Coiner participates in a quarterly bonus arrangement based on EBITDA from our commercial activities during the quarter. Other participants in the quarterly bonus arrangement include approximately 80 employees in the marketing and business development group. The total amount of quarterly bonuses paid pursuant to this arrangement during 2005 was approximately $8.1 million.

(5) Salary and bonus for Mr. Duckett are presented in U.S. dollar equivalent, based on the exchange rates in effect on the dates payments were made.

(6) The 2004 bonus amount includes $798,151 under a bonus program established at the time of the CANPET acquisition and $135,354 under a special 2004 retention bonus associated with the CANPET acquisition. Under the bonus program at PMC (Nova Scotia) Company established at the time of the CANPET purchase, all employees of PMC (Nova Scotia) Company are eligible to participate. The plan is based on EBITDA, and includes a quarterly bonus pool consisting of 4% of quarterly EBITDA and an annual bonus pool consisting of 6% of annual EBITDA.

(7) Employer contributions to PMC (Nova Scotia) Company savings plan and group term life insurance premiums.

(8) Includes quarterly bonuses (see footnote (4) above) aggregating $1,345,400, $537,800 and $423,300, and an annual bonus of $1,000,000, $300,000 and $200,000 for 2005, 2004 and 2003, respectively. The annual bonuses are payable 60% at the time of award and 20% in each of the two succeeding years.

Employment Contracts and Termination of Employment and Change-in-Control Arrangements

Mr. Armstrong is employed as Chairman and Chief Executive Officer. The initial three-year term of Mr. Armstrong's employment agreement commenced on June 30, 2001, and is automatically extended for one year on June 30 of each year (such that the term is reset to three years) unless Mr. Armstrong receives notice from the Chairman of the Compensation Committee that the Board of Directors has elected not to extend the agreement. Mr. Armstrong has agreed, during the term of the agreement and for five years thereafter, not to disclose (subject to typical exceptions) any confidential information obtained by him while employed under the agreement. The agreement provided for a base salary of $330,000 per year, subject to annual review. In February 2005, the annual salary was increased to $375,000. If Mr. Armstrong's employment is terminated without cause, he will be entitled to receive an amount equal to his annual base salary plus his highest annual bonus, multiplied by the lesser of (i) the number of years (including fractional years) remaining on the agreement and (ii) two. If Mr. Armstrong terminates his employment as a result of a change of control he will be entitled to receive an amount equal to three times the aggregate of his annual base salary and highest annual bonus. Under Mr. Armstrong's agreement, a "change of control" is defined to include (i) the acquisition by an entity or group (other than Plains Resources and its wholly owned subsidiaries) of 50% or more of our general partner or (ii) the existing owners of our general partner ceasing to own more than 50% of our general partner. If Mr. Armstrong's employment is terminated because of his death, a lump sum payment will be paid to his designee equal to his annual salary plus his highest annual bonus, multiplied by the lesser of (i) the number of years (including fractional years) remaining on the agreement and (ii) two. Under the agreement, Mr. Armstrong will be reimbursed for any excise tax due as a result of compensation (parachute) payments.

Mr. Pefanis is employed as President and Chief Operating Officer. The initial three-year term of Mr. Pefanis' employment agreement commenced on June 30, 2001, and is automatically extended for one year on June 30 of each year (such that the term is reset to three years) unless Mr. Pefanis receives notice from the Chairman of the Board of Directors that the Board has elected not to extend the agreement. Mr. Pefanis has agreed, during the term of the agreement and for one year thereafter, not to disclose (subject to typical exceptions) any confidential information obtained by him while employed under the agreement. The agreement provided for a base salary of $235,000 per year, subject to annual review. In February 2005, the annual salary was increased to $300,000. The provisions in Mr. Pefanis' agreement with respect to termination, change of control and related payment obligations are substantially similar to the parallel provisions in Mr. Armstrong's agreement.

In August 2005, Sable Investments, L.P., which owned 19% of our general partner interest, sold its interest to each of the other owners of the general partner, in proportion to their ownership interest. See Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder

Matters—Beneficial Ownership of General Partner Interest." The consummation of the sale and the resulting interest held by Vulcan Energy would have constituted a change of control under the employment agreements with Messrs. Armstrong and Pefanis. Mr. Armstrong and Mr. Pefanis each entered into an agreement waiving the change of control, contingent on the execution and performance by Vulcan Energy of a voting agreement with Plains All American GP LLC that restricts certain of Vulcan's voting rights. Upon a breach, termination or notice of termination of the voting agreement by Vulcan Energy, such waivers will terminate. See Item 13. "Certain Relationships and Related Transactions—Transactions with Related Parties."

In connection with Mr. vonBerg's employment in January 2002, our general partner and Mr. vonBerg entered into a letter agreement setting forth the terms of his employment. Such letter agreement provided for Mr. vonBerg's position to be Director, Trading at a base salary of $200,000 per year and his participation in a quarterly bonus pool based on gross margin generated by the employee's business unit, discretionary annual bonus pool and employee benefits provided to all employees generally. Through January 2007, the agreement provides that if Mr. vonBerg were terminated by our General Partner without cause or by him for good reason, he would continue to receive his monthly base salary for a period of twelve months. Mr. vonBerg also entered into an ancillary agreement which provides that for a period of one year following his termination, he will not disclose (subject to typical exceptions) any confidential information obtained by him while employed under the agreement and he will not, for two years after termination, engage in certain transactions with certain suppliers and customers.

See "—Long-Term Incentive Plans—2005 Long-Term Incentive Plan" for a discussion of termination of employment and change of control provisions affecting phantom units and associated distribution equivalent rights granted to the Named Executive Officers.

Long-Term Incentive Plans

1998 Long-Term Incentive Plan

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the "1998 LTIP") for employees and directors of our general partner and its affiliates who perform services for us. Awards contemplated by the 1998 LTIP include phantom units and unit options. As amended, the 1998 LTIP authorized the grant of phantom units and unit options covering an aggregate of 1,425,000 common units delivered upon vesting of such phantom units or unit options. Our general partner's board of directors has the right to alter or amend the 1998 LTIP or any part of the plan from time to time, including, subject to any applicable NYSE listing requirements, increasing the number of common units with respect to which awards may be granted; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of such participant.

Common units to be delivered upon the vesting of rights may be common units acquired by our general partner in the open market or in private transactions, common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. In addition, over the term of the plan we may issue new common units to satisfy delivery obligations under the grants. When we issue new common units upon vesting of grants, the total number of common units outstanding increases.

Phantom Units. A phantom unit entitles the grantee to receive, upon the vesting of the phantom unit, a common unit (or cash equivalent, depending on the terms of the grant). A substantial number of phantom units have vested under the 1998 LTIP. As of December 31, 2005, giving effect to vested grants, grants of approximately 48,275 unvested phantom units under the 1998 LTIP remain outstanding to employees, officers and directors of our general partner. The compensation committee or board of directors may, in the future, make additional grants under the plan to employees and directors containing

such terms as the compensation committee or board of directors shall determine, including tandem distribution equivalent rights ("DERs") with respect to phantom units. DERs entitle the grantee to a cash payment, either while the award is outstanding or upon vesting, equal to any cash distributions paid on a unit while the award is outstanding.

As of December 31, 2005, approximately 1,067,975 phantom units had vested under the 1998 LTIP. Approximately 471,492 units have been purchased and delivered or issued in satisfaction of vesting, after payment of cash-equivalents and netting for taxes.

The issuance of the common units upon vesting of phantom units is primarily intended to serve as a means of incentive compensation for performance. Therefore, no consideration is paid to us by the plan participants upon receipt of the common units.

The following table shows the vesting of phantom units granted under the 1998 LTIP to the Named Executive Officers.

		2003 Vesting		2004 Vesting		2005 Vesting	
Name	Total Units	Units	Value[(1)]	Units	Value[(1)]	Units	Value[(1)]
Greg L. Armstrong	70,000	—	—	52,500	$ 1,692,600	17,500	$ 701,575
Harry N. Pefanis	70,000	15,000	$ 452,400	52,500	$ 1,674,600	2,500	$ 100,225
George R. Coiner	67,500	7,500	$ 226,200	50,625	$ 1,643,138	9,375	$ 375,844
W. David Duckett	—	—	—	—	—	—	—
John P. vonBerg	12,500	—	—	9,375	$ 302,250	3,125	$ 125,281

(1) As of vesting dates.

Unit Option Plan. The unit option plan under our 1998 LTIP currently permits the grant of options covering common units. No grants have been made under the unit option plan to date. However, the compensation committee or board of directors may, in the future, make grants under the plan to employees and directors containing such terms as the compensation committee or board of directors shall determine, provided that unit options have an exercise price equal to the fair market value of the units on the date of grant.

2005 Long-Term Incentive Plan

In January 2005, our unitholders approved the Plains All American 2005 Long-Term Incentive Plan (the "2005 LTIP"). The 2005 LTIP provides for awards to the employees and directors of our general partner and its affiliates who perform services for us. Awards contemplated by the 2005 LTIP include phantom units, restricted units, unit appreciation rights and unit options, as determined by the compensation committee or board of directors (each an "Award"). Up to 3 million units may be issued in satisfaction of Awards. Certain Awards may also include DERs.

Common units to be delivered upon the vesting of rights may be common units acquired by our general partner in the open market or in private transactions, common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. In addition, over the term of the plan we may issue new common units to satisfy delivery obligations under the grants. When we issue new common units upon vesting of grants, the total number of common units outstanding increases.

The compensation committee and board of directors have approved grants under the 2005 LTIP of phantom units with associated DERs to the Named Executive Officers as follows:

Long-Term Incentive Plans—Awards in Last Fiscal Year

Number of Shares, Units or	Performance or Other Period	Estimated Future Payouts Under Non-Stock Price-Based Plans

Name	Other Rights[1]	Until Maturation or Payout	Threshold	Target	Maximum
Greg L. Armstrong	300,000	(2)	(2)	(2)	(2)
Harry N. Pefanis	200,000	(2)	(2)	(2)	(2)
George R. Coiner	80,000	(3)	(3)	(3)	(3)
	70,000	(4)	(4)	(4)	(4)
W. David Duckett	75,000	(3)	(3)	(3)	(3)
	50,000	(4)	(4)	(4)	(4)
John P. vonBerg	40,000	(3)	(3)	(3)	(3)
	50,000	(4)	(4)	(4)	(4)

(1) The awards reflected in the table include distribution equivalent rights (DERs).

(2) These phantom units will vest 30%, 30% and 40% solely upon achievement by the Partnership of annualized distributions of $2.60, $2.80 and $3.00 per unit and continued employment through May 2007, May 2009 and May 2010, respectively. Any phantom units that have not vested, and all associated DERs, as of the May 2012 distribution date will be forfeited. DERs associated with these phantom units become payable 30%, 15%, 15%, 20% and 20% upon the earlier to occur of annualized distributions of $2.60 or May 2007, $2.70 or May 2008, $2.80 or May 2009, $2.90 or May 2010, and $3.00 or May 2010, respectively.

(3) These phantom units will vest 40%, 30% and 30% upon achievement by the Partnership of annualized distributions of $2.60, $2.80 and $3.00 per unit and continued employment through May 2007, May 2009 and May 2010, respectively. Any phantom units that have not previously vested will fully vest on the May 2011 distribution date, subject to continued employment through such date. DERs associated with these phantom units become payable 40%, 15%, 15%, 15% and 15% upon the earlier to occur of annualized distributions of $2.60 or May 2007, $2.70 or May 2008, $2.80 or May 2009, $2.90 or May 2010, and $3.00 or May 2010, respectively.

(4) These phantom units will vest in equal one-third increments solely upon achievement by the Partnership of annualized distributions of $2.90, $3.00 and $3.10 per unit and continued employment through May 2008, May 2009 and May 2010, respectively. DERs associated with these phantom units vest and become payable in equal one-third increments solely upon the payment of annualized distributions of $2.90, $3.00, and $3.10, respectively. Any phantom units that have not vested, and all associated DERs, as of the May 2012 distribution date will be forfeited.

In addition to the vesting provisions described above, the following provisions also apply to Awards granted to the Named Executive Officers under the 2005 LTIP:

- In the event of termination of employment for reasons other than death, disability or change in status associated with a change of control (as defined in the Award agreement), all outstanding phantom units and associated DERs will be forfeited.
- In the event of termination of employment by the general partner other than for cause (as defined in the Award agreement), all phantom units that have satisfied vesting criteria but for the passage of time, will be deemed nonforfeitable and will vest on the next distribution date.
- In the event of termination of employment by death or disability, all phantom units and associated DERs will be deemed nonforfeitable and will continue to vest according to the vesting schedule described above.
- If a change in status (termination by the general partner other than for cause, removal from office or a reduction in salary or benefits) occurs within three months prior to or one year following a

change of control, all phantom units will be deemed nonforfeitable and will vest on the next distribution date.

The issuance of the common units upon vesting of phantom units is primarily intended to serve as a means of incentive compensation for performance. Therefore, no consideration is paid to us by the plan participants upon receipt of the common units.

Other Equity Grants

In 2001, our general partner established a Performance Option Plan funded by common units owned by the general partner. We have no obligation to reimburse the general partner for such units when they are delivered upon vesting of options granted under the Performance Option Plan. See Item 13. “Certain Relationships and Related Transactions—Transactions with Related Parties.”

Compensation of Directors

Each director of our general partner who is not an employee of our general partner is reimbursed for any travel, lodging and other out-of-pocket expenses related to meeting attendance or otherwise related to service on the board (including, without limitation, reimbursement for continuing education expenses). Non-employee directors receive no perquisites or other personal benefits. Each non-employee director is currently paid an annual retainer fee of $45,000. Mr. Armstrong is otherwise compensated for his services as an employee and therefore receives no separate compensation for his services as a director. In addition to the annual retainer, each committee chairman (other than the chairman of the audit committee) receives $2,000 annually. The chairman of the audit committee receives $30,000 annually, and the other members of the audit committee receive $15,000 annually, in each case, in addition to the annual retainer. Mr. Petersen assigns any compensation he receives in his capacity as a director to EnCap Energy Capital Fund III, L.P. (EnCap III), which is controlled by EnCap Investments L.P., of which Mr. Petersen is a Managing Director. Mr. Capobianco assigns any compensation he receives in his capacity as a director to Vulcan Capital.

Except as described below, each non-employee director has received an LTIP award of 5,000 units in the aggregate. These units vest annually in 25% increments, subject to an automatic re-grant of the amount vested, such that the director will always have outstanding an award of 5,000 units. For Mr. Petersen and Mr. Capobianco, a cash equivalent payment will be made to EnCap III and Vulcan Capital, respectively, upon any vesting. The units will vest in full upon the next vesting date after the death or disability (as determined in good faith by the board) of the director. For any “independent” directors (as defined in the GP LLC Agreement, and currently including Messrs. Goyanes, Smith and Symonds), the units will also vest in full if such director (i) retires (no longer with full-time employment and no longer serving as an officer or director of any public company) or (ii) is removed from the Board or is not reelected to the Board, unless such removal or failure to reelect is for “good cause,” as defined in the letter granting the phantom units.

Compensation Committee Interlocks and Insider Participation

Messrs. Capobianco, Petersen and Sinnott served on the compensation committee during 2005. During 2005, 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 and Sinnott are associated with business entities with which we have relationships. See Item 13. "Certain Relationships and Related Transactions."

Reimbursement of Expenses of Our General Partner and its Affiliates

We do not pay our general partner a management fee, but we do reimburse our general partner for all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion. See Item 13. "Certain Relationships and Related Transactions—Our General Partner."

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters*

Beneficial Ownership of Limited Partner Interest

Our common units outstanding represent 98% of our equity (limited partner interest). The 2% general partner interest is discussed separately below under "—Beneficial Ownership of General Partner Interest." The following table sets forth the beneficial ownership of limited partner units held by beneficial owners of 5% or more of the units, directors, the Named Executive Officers, and all directors and executive officers as a group as of February 17, 2006.

Name of Beneficial Owner	Common Units	Percentage of Common Units[(1)]
Paul G. Allen	13,688,400[(2)]	18.6%
Vulcan Energy Corporation	12,390,120[(3)]	16.8%
Richard Kayne/Kayne Anderson Capital Advisors, L.P.	6,594,824[(4)]	8.9%
Greg L. Armstrong	249,562[(5)(6)(7)]	[(8)]
Harry N. Pefanis	145,027[(6)(7)]	[(8)]
George R. Coiner	54,276[(6)(7)]	[(8)]
W. David Duckett	119,541[(6)]	[(8)]
John P.vonBerg	11,687[(6)]	[(8)]
David N. Capobianco	—[(9)]	[(8)]
Everardo Goyanes	8,700	[(8)]
Gary R. Petersen	7,700[(10)]	[(8)]
Robert V. Sinnott	15,000[(11)]	[(8)]
Arthur L. Smith	11,250	[(8)]
J. Taft Symonds	20,000	[(8)]
All directors and executive officers as a group (23 persons)	904,483[(7)(12)]	1.2%

(1) Limited partner units constitute 98% of our equity, with the remaining 2% held by our general partner. The beneficial ownership of our general partner is set forth in the table below under "—Beneficial Ownership of General Partner Interest." Giving effect to the indirect ownership by Vulcan Energy Corporation of a portion of our general partner, Mr. Allen may be deemed to beneficially own approximately 19.3% of our total equity. Mr. Allen disclaims any deemed beneficial ownership, beyond his pecuniary interest, in any of our partner interests held by Vulcan Energy Corporation or any of its affiliates.

(2) Mr. Allen owns approximately 88.38% of the outstanding shares of common stock of Vulcan Energy Corporation. Mr. Allen also controls Vulcan Capital Private Equity I LLC ("Vulcan LLC"), which is the record holder of 1,298,280 common units. The address for Mr. Allen and Vulcan LLC is 505 Fifth Avenue S, Suite 900, Seattle, Washington 98104. Mr. Allen disclaims any deemed beneficial ownership, beyond his pecuniary interest, in any of our partner interests held by Vulcan Energy Corporation or any of its affiliates.

(3) The address for Vulcan Energy Corporation is c/o Plains All American GP LLC, 333 Clay Street, Suite 1600, Houston, Texas 77002.

(4) Richard A. Kayne is Chief Executive Officer and Director of Kayne Anderson Investment Management, Inc., which is the general partner of Kayne Anderson Capital Advisors, L.P. ("KACALP"). Various accounts (including KAFU Holdings, L.P., which owns a portion of our general partner) under the management or control of KACALP own 6,594,824 common units. Mr. Kayne may be deemed to beneficially own such units. In addition, Mr. Kayne directly owns or has sole voting and dispositive power over 270,365 common units. Mr. Kayne disclaims beneficial ownership of any of our partner interests other than units held by him or interests attributable to him by virtue of his interests in the accounts that own our partner interests. The address for Mr. Kayne and Kayne Anderson Investment Management, Inc. is 1800 Avenue of the Stars, 2nd Floor, Los Angeles, California 90067.

(5) Does not include approximately 200,662 common units owned by our general partner in connection with the Performance Option Plan. Mr. Armstrong disclaims any beneficial ownership of such units beyond his rights as a grantee under the plan. See Item 13. "Certain Relationships and Related Transactions—Transactions with Related Parties—Performance Option Plan."

(6) Does not include unvested phantom units granted under the 2005 LTIP, none of which will vest within 60 days of the date hereof. See Item 11. "Executive Compensation—Long-Term Incentive Plans—2005 Long-Term Incentive Plan."

(7) Includes the following vested, unexercised options to purchase common units under the Performance Option Plan. Mr. Armstrong: 37,500; Mr. Pefanis: 27,500; Mr. Coiner: 21,250; and all directors and executive officers as a group: 153,750.

(8) Less than one percent.

(9) The GP LLC Agreement specifies that certain of the owners of our general partner have the right to designate a member of our board of directors. Mr. Capobianco has been designated one of our directors by Vulcan Energy Corporation, of which he is Chairman of the Board. Mr. Capobianco owns an equity interest in Vulcan LLC and has the right to receive a performance-based fee based on the performance of the holdings of Vulcan LLC and Vulcan Energy Corporation. Mr. Capobianco disclaims any deemed beneficial ownership of our partner interests held by Vulcan Energy Corporation and Vulcan LLC or any of their affiliates beyond his pecuniary interest therein,

if any. By virtue of its 54% ownership in the general partner, Vulcan Energy Corporation has the right at any time to cause the election of an additional director to the Board.

(10) Includes 5,200 common units owned by EnCap Energy Capital Fund III, L.P. Mr. Petersen disclaims beneficial ownership of these units in excess of his pecuniary interest in such units. Pursuant to the GP LLC Agreement, Mr. Petersen has been designated one of our directors by E-Holdings III, L.P., an affiliate of EnCap Investments L.P., of which he is Senior Managing Director. Mr. Petersen disclaims any deemed beneficial ownership of any of our partner interests owned by E-Holdings III, L.P. or other affiliates of EnCap Investments L.P. beyond his pecuniary interest. The address for E-Holdings III, L.P. is 1100 Louisiana, Suite 3150, Houston, Texas 77002.

(11) Pursuant to the GP LLC Agreement, Mr. Sinnott has been designated one of our directors by KAFU Holdings, L.P., which is controlled by Kayne Anderson Investment Management, Inc., of which he is President. Mr. Sinnott disclaims any deemed beneficial ownership of any units held by KAFU Holdings, L.P. or its affiliates, other than through his 4.5% limited partner interest in KAFU Holdings, L.P. The address for KAFU Holdings, L.P. is 1800 Avenue of the Stars, 2nd Floor, Los Angeles, California 90067.

(12) Includes 6,000 phantom units granted under the 2005 LTIP which will vest within 60 days of the date hereof.

Beneficial Ownership of General Partner Interest

Plains AAP, L.P. owns all of our 2% general partner interest and all of our incentive distribution rights. The following table sets forth the effective ownership of Plains AAP, L.P. (after giving effect to proportionate ownership of Plains All American GP LLC, its 1% general partner).

Name and Address of Owner	Percentage Ownership of Plains AAP
Paul G. Allen[1] 505 Fifth Avenue S, Suite 900 Seattle, WA 98104	54.3%
Vulcan Energy Corporation[2] c/o Plains All American GP LLC 333 Clay Street, Suite 1600 Houston, TX 77002	54.3%
KAFU Holdings, L.P.[3] 1800 Avenue of the Stars, 2nd Floor Los Angeles, CA 90067	20.3%
E-Holdings III, L.P.[4] 1100 Louisiana, Suite 3150 Houston, TX 77002	9.0%
E-Holdings V, L.P.[4] 1100 Louisiana, Suite 3150 Houston, TX 77002	2.1%
PAA Management, L.P.[5] 333 Clay Street, Suite 1600 Houston, TX 77002	4.9%
Wachovia Investors, Inc 301 South College Street, 12th Floor Charlotte, NC 28288	4.2%
Mark E. Strome 100 Wilshire Blvd., Suite 1500 Santa Monica, CA 90401	2.6%
Strome MLP Fund, L.P 100 Wilshire Blvd., Suite 1500 Santa Monica, CA 90401	1.3%
Lynx Holdings I, LLC 15209 Westheimer, Suite 110 Houston, TX 77082	1.2%

(1) Mr. Allen owns approximately 88.38% of the outstanding shares of common stock of Vulcan Energy Corporation. A subsidiary of Vulcan Energy Corporation owns 54.321% of the equity of our general partner. Mr. Allen disclaims any deemed beneficial ownership, beyond his pecuniary interest, in any of our partner interests held by Vulcan Energy Corporation or any of its affiliates.

(2) Mr. Capobianco disclaims any deemed beneficial ownership of the interests held by Vulcan Energy Corporation and its affiliates beyond his pecuniary interest therein, if any.

(3) Mr. Sinnott disclaims any deemed beneficial ownership of the interests owned by KAFU Holdings, L.P. other than through his 4.5% limited partner interest in KAFU Holdings, L.P.

(4) Mr. Petersen disclaims any deemed beneficial ownership of the interests owned by E-Holdings III, L.P. and E-Holdings V, L.P. beyond his pecuniary interest.

(5) PAA Management, L.P. is owned entirely by certain members of senior management, including Messrs. Armstrong (approximately 25%), Pefanis (approximately 14%), Coiner (approximately 9%), Duckett (approximately 4%) and vonBerg (approximately 4%). Other than Mr. Armstrong, no directors own any interest in PAA Management, L.P. Directors and executive officers as a group own approximately 95% of PAA Management, L.P. Mr. Armstrong disclaims any beneficial ownership of the general partner interest owned by Plains AAP, L.P., other than through his ownership interest in PAA Management, L.P.

Equity Compensation Plan Information

The following table sets forth certain information with respect to our equity compensation plans as of December 31, 2005. For a description of these plans, see Item 11. "Executive Compensation."

Plan Category	Number of Units to be Issued upon Exercise/Vesting of Outstanding Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Units Remaining Available for Future Issuance under Equity Compensation Plans (c)
Equity compensation plans approved by unitholders:			
1998 Long Term Incentive Plan	48,275(1)	N/A(2)	498,983(1)(3)
2005 Long Term Incentive Plan	2,178,200(4)	N/A(2)	821,800(3)
Equity compensation plans not approved by unitholders:			
1998 Long Term Incentive Plan	—(1)(5)	N/A(2)	—(6)
Performance Option Plan	—(7)	$ 13.85(8)	—(7)

(1) As originally instituted by our former general partner prior to our initial public offering, the 1998 LTIP contemplated the issuance of up to 975,000 common units to satisfy awards of phantom units. Upon vesting, these awards could be satisfied either by (i) primary issuance of units by us or (ii) cash settlement or purchase of units by our general partner with the cost reimbursed by us. In 2000, the 1998 LTIP was amended, as provided in the plan, without unitholder approval to increase the maximum awards to 1,425,000 phantom units; however, we can issue no more than 975,000 new units to satisfy the awards. Any additional units must be purchased by our general partner in the open market or in private transactions and be reimbursed by us. As of December 31, 2005, we have issued approximately 427,742 common units in satisfaction of vesting under the 1998 LTIP. The number of units presented in column (a) assumes that all remaining grants will be satisfied by the issuance of new units upon vesting. In fact, a substantial number of phantom units that have vested were satisfied without the issuance of units. These phantom units were settled in cash or withheld for taxes. Any units not issued upon vesting will become "available for future issuance" under column (c).

(2) Phantom unit awards under the 1998 LTIP and 2005 LTIP vest without payment by recipients.

(3) In accordance with Item 201(d) of Regulation S-K, column (c) excludes the securities disclosed in column (a). However, as discussed in footnotes (1) and (4), any phantom units represented in column (a) that are not satisfied by the issuance of units become "available for future issuance."

(4) The 2005 Long Term Incentive Plan was approved by our unitholders in January 2005. The 2005 LTIP contemplates the issuance or delivery of up to 3,000,000 units to satisfy awards under the plan. The number of units presented in column (a) assumes that all outstanding grants will be satisfied by the issuance of new units upon vesting. In fact, some portion of the phantom units may be settled in cash and some portion will be withheld for taxes. Any units not issued upon vesting will become "available for future issuance" under column (c).

(5) Although awards for units may from time to time be outstanding under the portion of the 1998 LTIP not approved by unitholders, all of these awards must be satisfied in cash or out of units purchased by our general partner and reimbursed by us. None will be satisfied by "units issued upon exercise/vesting."

(6) Awards for up to 406,250 phantom units may be granted under the portion of the 1998 LTIP not approved by unitholders; however, no common units are "available for future issuance" under the plan, because all such awards must be satisfied with cash or out of units purchased by our general partner and reimbursed by us.

(7) Our general partner has adopted and maintains a Performance Option Plan for officers and key employees pursuant to which optionees have the right to purchase units from the general partner. The 450,000 units that were originally authorized to be sold under the plan were contributed to the general partner by certain of its owners in connection with the transfer of a majority of our general partner interest in 2001 without economic cost to the Partnership. Thus, there will be no units "issued upon exercise/vesting of outstanding options." Approximately 448,000 unit options have been granted out of the 450,000 units originally available under the plan. Options for approximately 169,000 units are currently outstanding and approximately 2,000 units are available for future option grants. See Item 11."Executive Compensation—Other Equity Grants."

(8) As of December 31, 2005, the strike price for all outstanding options under the Performance Option Plan was approximately $13.85 per unit. The strike price decreases as distributions are paid. See Item 11. "Executive Compensation—Other Equity Grants."

Item 13. *Certain Relationships and Related Transactions*

Our General Partner

Our operations and activities are managed, and our officers and personnel are employed, by our general partner (or, in the case of our Canadian operations, PMC (Nova Scotia) Company). We do not pay our general partner a management fee, but we do reimburse our general partner for all expenses incurred on our behalf. Total costs reimbursed by us to our general partner for the year ended December 31, 2005 were approximately $165.2 million.

Our general partner owns the 2% general partner interest and all of the incentive distribution rights. 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, generally our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 ($1.80 annualized) per unit, 25% of the amounts we distribute in excess of $0.495 ($1.98 annualized) per unit and 50% of amounts we distribute in excess of $0.675 ($2.70 annualized) per unit.

The following table illustrates the allocation of aggregate distributions at different per-unit levels:

Annual Distribution Per Unit	Distribution to Unitholders(1)(2)	Distribution to GP(1)(2)(3)	Total Distribution(1)	GP Percentage of Total Distribution
$1.80	$ 135,000	$ 2,755	$ 137,755	2.0%
$1.98	$ 148,500	$ 5,137	$ 153,637	3.3%
$2.70	$ 202,500	$ 23,137	$ 225,637	10.3%

$2.90	$ 217,500	$ 38,137	$ 255,637	14.9%
$3.10	$ 232,500	$ 53,137	$ 285,637	18.6%
$3.30	$ 247,500	$ 68,137	$ 315,637	21.6%

(1) In thousands.

(2) Assumes 75,000,000 units outstanding. Actual number of units outstanding as of December 31, 2005 was 73,768,576. An increase in the number of units outstanding would increase both the distribution to unitholders and the distribution to the general partner of any given level of distribution per unit.

(3) Includes distributions attributable to the 2% general partner interest and the incentive distribution rights.

Transactions with Related Parties

Vulcan Energy

As of December 31, 2005, Vulcan Energy and its affiliates owned approximately 54% of our general partner interest, as well as approximately 16.8% of our outstanding limited partner units.

Voting Agreement

In August 2005, one of the owners of our general partner notified the remaining owners of its intent to sell its 19% interest in the general partner. The remaining owners elected to exercise their right of first refusal, such that the 19% interest was purchased pro rata by all remaining owners. As a result of the transaction, the interest of Vulcan Energy increased from 44% to approximately 54%. At the closing of the transaction, Vulcan Energy entered into a voting agreement that restricts its ability to unilaterally elect or remove our independent directors, and separately, our CEO and COO agreed, subject to certain ongoing conditions, to waive certain change-of-control payment rights that would otherwise have been triggered by the increase in Vulcan Energy's ownership interest. These ownership changes to our general partner had no impact on us.

Administrative Services Agreement

On October 14, 2005, GP LLC and Vulcan Energy entered into an Administrative Services Agreement, effective as of September 1, 2005 (the "Services Agreement"). Pursuant to the Services Agreement, GP LLC will provide administrative services to Vulcan Energy for consideration of approximately $650,000 per year, plus certain expenses. The Services Agreement will be effective for a period of three years, at which time it will automatically renew for successive one-year periods unless either party provides written notice of its intention to terminate the Services Agreement. Pursuant to the agreement, Vulcan Energy has appointed certain employees of GP LLC as officers of Vulcan Energy for administrative efficiency. Under the Services Agreement, Vulcan Energy acknowledges that conflicts may arise between itself and GP LLC. If GP LLC believes that a specific service is in conflict with the best interest of GP LLC or its affiliates then GP LLC is entitled to suspend the provision of that service and such a suspension will not constitute a breach of the Services Agreement. Vulcan Gas Storage LLC (discussed below) operates separately from Vulcan Energy, and services we provide to Vulcan Gas Storage LLC are not covered under the Services Agreement.

Predecessor Agreements

In 2001, Plains Resources, Inc. transferred a portion of its indirect interest in our general partner to certain of the current owners. As successor in interest to Plains Resources, Vulcan Energy is party to certain agreements related to such transfer, including the following:

- a separation agreement entered into in 2001 in connection with the transfer of interests in our general partner pursuant to which (i) Vulcan indemnifies us for (a) claims relating to securities laws or regulations in connection with the upstream or midstream businesses, based on alleged acts or omissions occurring on or prior to June 8, 2001, or (b) claims related to the upstream business, whenever arising, and (ii) we indemnify Vulcan for claims related to the midstream business, whenever arising. Vulcan also indemnifies, and maintains liability insurance (through June 8, 2007) for the individuals who were, on or before June 8, 2001, directors or officers of Plains Resources or our former general partner.
- a Pension and Employee Benefits Assumption and Transition Services Agreement that provided for the transfer to our general partner of the employees of our former general partner and certain headquarters employees of Plains Resources.

- an Omnibus Agreement that provides for the resolution of certain conflicts of interest, including certain non-compete obligations.

Crude Oil Purchases

Until August 12, 2005, Vulcan Energy owned 100% of Calumet Florida L.L.C. Calumet is now owned by Vulcan Resources Florida, Inc., the majority of which is owned by Paul G. Allen. We purchase crude oil from Calumet. We paid approximately $38.1 million to Calumet in 2005.

Equity Offering

On February 25, 2005, we issued 575,000 common units in a private placement to a subsidiary of Vulcan Capital. The sale price was $38.13 per unit, which represented a 2.8% discount to the closing price of the units on February 24, 2005. The sale resulted in net proceeds, including the general partner's proportionate capital contribution ($0.5 million) and net of expenses associated with the sale, of approximately $22.3 million. The net proceeds were initially used to repay indebtedness under our revolving credit facilities, and to fund a portion of our 2005 expansion capital program as those expenditures were incurred.

Long-Term Incentive Plans

Our general partner maintains the 1998 LTIP and the 2005 LTIP for employees and directors of our general partner. The plans generally consist of two components, a restricted or phantom unit plan and a unit option plan, and cover delivery of an aggregate of 4,425,000 common units. The plans are administered by the compensation committee of our general partner's board of directors.

As of December 31, 2005, approximately 427,742 common units have been issued in satisfaction of vesting of previous awards, and grants of approximately 2.2 million phantom or restricted units remain outstanding to employees, officers and directors of our general partner under these plans. See Item 11. "Executive Compensation—Long-Term Incentive Plans."

Performance Option Plan

In 2001, the owners of the general partner (other than PAA Management, L.P.) contributed an aggregate of 450,000 subordinated units (now converted into common units) to the general partner to provide a pool of units available for the grant of options to management and key employees. In that regard, the general partner adopted the Plains All American 2001 Performance Option Plan, pursuant to which options to purchase approximately 448,000 units have been granted. Of this amount, 75,000, 55,000, 72,500, 15,000 and 26,500 were granted to Messrs. Armstrong, Pefanis, Coiner, Duckett and vonBerg, respectively, and approximately 405,000 to executive officers as a group. The amounts presented for Messrs. Coiner, Duckett and vonBerg include 30,000, 15,000 and 14,000 options, respectively, granted in 2005, which collectively represented all options granted under the plan during 2005. These options vested and were either exercised in full or cancelled for a cash payment during 2005 (see table below). As of December 31, 2005, 169,000 options remain outstanding under the plan, all of which are fully vested. The original exercise price of the options was $22 per unit, declining over time by an amount equal to 80% of each quarterly distribution per unit. As of December 31, 2005, the exercise price was approximately $13.85 per unit. The terms of future grants may differ from the existing grants. Because the units underlying the plan were contributed to the general partner, we have no obligation to reimburse the general partner for the cost of the units upon exercise of the options.

On November 2, 2005, a special committee of the board of directors approved a program pursuant to which the general partner sold in the market a portion of the units subject to the plan. The sales were made pursuant to a plan meeting the requirements of Rule 10b5-1 of the Securities Exchange Act. Officers

who held options expiring in 2005 were provided the opportunity to participate in the program by agreeing to cancel those options in exchange for a cash payment from the proceeds of the sales. Participants in the program included Messrs. Pefanis, Coiner and Duckett. An aggregate of approximately 167,250 options were cancelled under the program, including 27,500 for Mr. Pefanis, 51,250 for Mr. Coiner and 15,000 for Mr. Duckett.

The following table provides information with respect to aggregate option exercises in the last fiscal year and fiscal year-end option values for the Named Executive Officers.

Aggregated Option Exercises in Fiscal 2005 and Fiscal Year-End Option Values

Name	Units Acquired on Exercise	Value Realized	Number of Securities Underlying Unexercised Options at December 31, 2005		Value of Unexercised In-The-Money Options at December 31, 2005[3]	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Greg L. Armstrong	37,500	$ 1,029,263[1]	37,500	—	$ 964,575	—
Harry N. Pefanis	27,500[2]	$ 731,064[2]	27,500	—	$ 707,355	—
George R. Coiner	51,250[2]	$ 1,362,437[2]	21,250	—	$ 546,593	—
W. David Duckett	15,000[2]	$ 398,762[2]	—	—	—	—
John P. vonBerg	23,375	$ 687,443[1]	—	—	—	—

(1) Computed based on the difference between the closing price of the common units on the day of exercise and the exercise price.

(2) These options were cancelled in exchange for a cash payment equal to approximately $26.58 per unit. The value realized is equal to the cash amount received; no units were received.

(3) Computed based on the difference between the closing price on December 30, 2005 and the exercise price.

Tank Car Lease and CANPET

In July 2001, we acquired the assets of CANPET Energy Group Inc., a Calgary-based Canadian crude oil and LPG marketing company (the "CANPET acquisition"), for approximately $24.6 million plus excess inventory at the closing date of approximately $25.0 million. Mr. W. David Duckett, the President of PMC (Nova Scotia) Company, the general partner of Plains Marketing Canada, L.P., owns approximately 37.8% of CANPET. In connection with the CANPET acquisition, Plains Marketing Canada, L.P. assumed CANPET's rights and obligations under a Master Railcar Leasing Agreement between CANPET and Pivotal Enterprises Corporation ("Pivotal"). The agreement provides for Plains Marketing Canada, L.P. to lease approximately 57 railcars from Pivotal at a lease price of $1,000 (Canadian) per month, per car. The lease extends until June of 2008, with an option for Pivotal to extend the term of the lease for an additional five years. Pivotal is substantially owned by former employees of CANPET, including Mr. Duckett. Mr. Duckett owns a 23.4% interest in Pivotal.

Class C Common Units

In April 2004, we sold 3,245,700 unregistered Class C common units (the "Class C common units") to a group of investors consisting of affiliates of Kayne Anderson Capital Advisors, Vulcan Capital and Tortoise Capital pursuant to Rule 4(2) under the Securities Act. For more detailed information with respect to our relationship with Kayne Anderson Capital Advisors and Vulcan Capital, see Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters." We received $30.81 per Class C common unit, an amount which represented 94% of the average closing price of our common units for the twenty trading days immediately ending on and including March 26, 2004. Net proceeds from the private placement, including the general partner's proportionate capital contribution and expenses associated with the sale, were approximately $101 million. We used the net proceeds from the offering to repay indebtedness under our revolving credit facility incurred in connection with the Link acquisition. In January 2005, our common unitholders approved a change in the terms of the Class C common units such that they were immediately convertible into an equal number of common units at the option of the holders, and in February 2005, all of the Class C common units converted.

Investment in Natural Gas Storage Joint Venture

PAA/Vulcan Gas Storage, LLC (“PAA/Vulcan”), a limited liability company, was formed in the third quarter of 2005. We own 50% of PAA/Vulcan and the remaining 50% is owned by Vulcan Gas Storage LLC, a subsidiary of Vulcan Capital, the investment arm of Paul G. Allen. The Board of Directors of PAA/Vulcan consists of an equal number of our representatives and representatives of Vulcan Gas Storage, and is responsible for providing strategic direction and policy-making. We, as the managing member, are responsible for the day-to-day operations.

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 and Vulcan Gas Storage LLC each made an initial cash investment of approximately $112.5 million, and Bluewater Natural Gas Holdings, LLC a subsidiary of PAA/Vulcan (“Bluewater”) entered into a $90 million credit facility contemporaneously with closing. Approximately $87.6 million was outstanding under this credit facility as of February 27, 2006. We currently have no direct or contingent obligations under the Bluewater credit facility.

Approximately $255 million of the total funding of $315 million was used to finance the acquisition and closing costs. It is anticipated that the remaining balance will be combined with funds obtained from financing activities related to the construction of the Pine Prairie facility, an underground natural gas storage facility in South Louisiana.

Pine Prairie has entered into a commitment letter with respect to a credit facility consisting of a senior secured revolving credit facility and a senior secured term loan. The terms of the credit facility will require Pine Prairie to establish a cash reserve for construction cost overruns. We anticipate the credit facility will be sized and structured such that PAA will not have to contribute additional equity to fund the Pine Prairie development, however the commitment letter anticipates that we will agree to make a contingent equity contribution in certain situations if the cash reserve is exhausted.

Proper functioning of the Pine Prairie storage caverns will require a minimum operating inventory contained in the caverns at all times (referred to as “pad gas” or “base gas”). We estimate that it will require approximately 7 bcf of pad gas. The Pine Prairie commitment letter contemplates that we will ensure that Pine Prairie can obtain the pad gas at $8.50 per mcf. We have entered into arrangements on behalf of PAA/Vulcan, which has secured the required gas at a price below the specified threshold. In order to hedge a portion of the uncontracted storage space to be constructed, we also anticipate entering into natural gas spread arrangements on behalf of PAA/Vulcan. In each case, we will charge a fee for such services consistent with our normal practices with third parties.

We and Vulcan Gas Storage are both required to make capital contributions in equal proportions to fund (i) certain projects specified at the time PAA/Vulcan acquired ECI and (ii) unspecified future capital needs up to an aggregate of $20 million. For certain other specified projects, Vulcan Gas Storage has the right, but not the obligation, to participate for 50% of the cost. For any other project (or a project in which Vulcan Gas Storage declines to exercise its right to participate), we have the right to make additional capital contributions to fund 100% of the project. Such contributions would increase our interest in PAA/Vulcan and dilute Vulcan Gas Storage’s interest. If at any time our interest in PAA/Vulcan exceeds 70%, Vulcan Gas Storage would have the right, but not the obligation, to make capital contributions proportionate to its ownership interest at the time.

In conjunction with formation of PAA/Vulcan and the acquisition of ECI, PAA and Paul G. Allen 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. PAA and Paul G. Allen would be required to perform under these guarantees only if ECI was unable to perform. In addition, we provided a guarantee under one contract with an indefinite life for which neither Vulcan Capital nor Paul G. Allen provided a guarantee. In exchange for the disproportionate guarantee, PAA will receive preference

distributions totaling $1.0 million over ten years from PAA/Vulcan (distributions that would otherwise have been paid to Vulcan Gas Storage LLC). 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 extremely remote; however, there is no dollar limitation on potential future payments that fall under this obligation.

PAA/Vulcan will reimburse us for the allocated costs of PAA’s non-officer staff associated with the management and day-to-day operations of PAA/Vulcan and all out-of-pocket costs. In addition, in the first fiscal year that EBITDA (as defined in the PAA/Vulcan LLC agreement) of PAA/Vulcan exceeds $75.0 million, we will receive a distribution from PAA/Vulcan equal to $6.0 million per year for each year since formation of the joint venture, subject to a maximum of 5 years or $30 million. Thereafter, we will receive annually a distribution equal to the greater of $2 million per year or two percent of the EBITDA of PAA/Vulcan.

Other

In September 2005, we sold 4,500,000 units in a public offering at a unit price to the public of $42.20. We received net proceeds of approximately $182.3 million, or $40.512 per unit after underwriters’ discounts and commissions. Concurrently with the public offering, we sold 679,000 common units pursuant to our existing shelf registration statement to investment funds affiliated with KACALP in a privately negotiated transaction for a purchase price of $40.512 per unit (equivalent to the public offering price less underwriting discounts and commissions). KACALP is an owner of our General Partner, with a representative on our Board of Directors.

Thomas Coiner, an employee in our marketing department, is the son of George R. Coiner, Senior Group Vice President. In 2005, Thomas Coiner received compensation in excess of $60,000.

Item 14. *Principal Accountant Fees and Services*

All services provided by our independent auditor are subject to pre-approval by our audit committee. The audit committee has instituted a policy that describes certain pre-approved non-audit services. We believe that the description of services is designed to be sufficiently detailed as to particular services provided, such that (i) management is not required to exercise judgment as to whether a proposed service fits within the description and (ii) the audit committee knows what services it is being asked to pre-approve. The audit committee is informed of each engagement of the independent auditor to provide services under the policy.

The following table details the aggregate fees billed for professional services rendered by our independent auditor (in millions):

	Year Ended December 31, 2005	Year Ended December 31, 2004
Audit fees(1)	$ 2.2	$ 2.8
Audit-related fees(2)	0.1	0.2
Tax fees(3)	0.5	0.8
All other fees(4)	0.3	0.6
Total	$ 3.1	$ 4.4

(1) Audit fees include those related to our annual audit (including internal control evaluation and reporting), audits of our general partner and certain joint ventures of which we are the operator, and work performed on our registration of publicly-held debt and equity.

(2) Audit-related fees primarily relate to audits of our benefit plans and carve-out audits of acquired companies.

(3) Tax fees are related to tax processing as well as the preparation of Forms K-1 for our unitholders.

(4) All other fees primarily consist of those associated with due diligence performed on our behalf and evaluating potential acquisitions.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a)(1) and (2) Financial Statements and Financial Statement Schedules

See "Index to the Consolidated Financial Statements" set forth on Page F-1.

All schedules are omitted because they are not applicable, or the required information is shown in the consolidated financial statements or notes thereto.

(a)(3) Exhibits

3.1	—	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 27, 2001), as amended by Amendment No. 1 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., dated as of April 15, 2004 (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
3.2	—	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
3.3	—	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
3.4	—	Certificate of Incorporation of PAA Finance Corp. (incorporated by reference to Exhibit 3.6 to the Registration Statement on Form S-3 filed August 27, 2001)
3.5	—	Bylaws of PAA Finance Corp. (incorporated by reference to Exhibit 3.7 to the Registration Statement on Form S-3 filed August 27, 2001)
3.6	—	Second Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC, dated September 12, 2005 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 16, 2005)
3.7	—	Second Amended and Restated Limited Partnership Agreement of Plains AAP, L.P., dated September 12, 2005 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed September 16, 2005)
4.1	—	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002)
4.2	—	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002)
4.3	—	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003)

4.4	—	Third Supplemental Indenture (Series A and Series B 4.75% Senior Notes due 2009) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S-4, File No. 333-121168)
4.5	—	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168)
4.6	—	Class C Common Unit Purchase Agreement by and among Plains All American Pipeline, L.P., Kayne Anderson Energy Fund II, L.P., KAFU Holdings, L.P., Kayne Anderson Capital Income Partners, L.P., Kayne Anderson MLP Fund, L.L.P., Tortoise Energy Infrastructure Corporation

and Vulcan Energy II Inc. dated March 31, 2004 (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)

4.7 — Registration Rights Agreement by and among Plains All American Pipeline, L.P., Kayne Anderson Energy Fund II, L.P., KAFU Holdings, L.P., Kayne Anderson Capital Income Partners (QP), L.P., Kayne Anderson MLP Fund, L.P., Tortoise Energy Infrastructure Corporation and Vulcan Energy II Inc. dated April 15, 2004 (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)

4.8 — Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005)

10.1 — Amended and Restated Credit Agreement dated November 4, 2005 among Plains All American Pipeline, L.P. (as US Borrower), PMC (Nova Scotia) Company and Plains Marketing Canada, L.P. (as Canadian Borrowers), and Bank of America, N.A. (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2005)

10.2 — Restated Credit Facility (Uncommitted Senior Secured Discretionary Contango Facility) dated November 19, 2004 among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed November 24, 2004)

10.3 — Amended and Restated Crude Oil Marketing Agreement, dated as of July 23, 2004, among Plains Resources Inc., Calumet Florida Inc. and Plains Marketing, L.P. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004)

10.4 — Amended and Restated Omnibus Agreement, dated as of July 23, 2004, among Plains Resources Inc., Plains All American Pipeline, L.P., Plains Marketing, L.P., Plains Pipeline, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004)

10.5 — Contribution, Assignment and Amendment Agreement, dated as of June 27, 2001, among Plains All American Pipeline, L.P., Plains Marketing, L.P., All American Pipeline, L.P., Plains AAP, L.P., Plains All American GP LLC and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 27, 2001)

10.6 — Contribution, Assignment and Amendment Agreement, dated as of June 8, 2001, among Plains All American Inc., Plains AAP, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 11, 2001)

10.7 — Separation Agreement, dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc., Plains All American GP LLC, Plains AAP, L.P. and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed June 11, 2001)

10.8[**] — Pension and Employee Benefits Assumption and Transition Agreement, dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed June 11, 2001)

10.9[**] — Plains All American GP LLC 2005 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 26, 2005.)

10.10[**] — Plains All American GP LLC 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to Registration Statement on Form S-8, File No. 333-74920) as amended June 27, 2003 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003)

10.11[**] — Plains All American 2001 Performance Option Plan (incorporated by reference to Exhibit 99.2 to the Registration Statement on Form S-8, File No. 333-74920)

10.12[**] — Amended and Restated Employment Agreement between Plains All American GP LLC and Greg L. Armstrong dated as of June 30, 2001 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001)

10.13[**] — Amended and Restated Employment Agreement between Plains All American GP LLC and Harry N. Pefanis dated as of June 30, 2001 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001)

10.14 — Asset Purchase and Sale Agreement dated February 28, 2001 between Murphy Oil Company Ltd. and Plains Marketing Canada, L.P. (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed May 10, 2001)

10.15 — Transportation Agreement dated July 30, 1993, between All American Pipeline Company and Exxon Company, U.S.A. (incorporated by reference to Exhibit 10.9 to the Registration Statement on Form S-1, File No. 333-64107)

10.16	—	Transportation Agreement dated August 2, 1993, among All American Pipeline Company, Texaco Trading and Transportation Inc., Chevron U.S.A. and Sun Operating Limited Partnership (incorporated by reference to Exhibit 10.10 to the Registration Statement on Form S-1, File No. 333-64107)
10.17	—	First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to the Annual Report on Form 10-K for the year ended December 31, 1998)

10.18	—	Agreement for Purchase and Sale of Membership Interest in Scurlock Permian LLC between Marathon Ashland LLC and Plains Marketing, L.P. dated as of March 17, 1999 (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 1998)
10.19**	—	Plains All American Inc. 1998 Management Incentive Plan (incorporated by reference to Exhibit 10.5 to the Annual Report on Form 10-K for the year ended December 31, 1998)
10.20**	—	PMC (Nova Scotia) Company Bonus Program (incorporated by reference to Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2004)
10.21**+	—	Quarterly Bonus Summary
10.22**+	—	Directors’ Compensation Summary
10.23	—	Master Railcar Leasing Agreement dated as of May 25, 1998 (effective June 1, 1998), between Pivotal Enterprises Corporation and CANPET Energy Group, Inc., (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 2001)
10.24**+	—	Form of LTIP Grant Letter (Armstrong/Pefanis)
10.25**	—	Form of LTIP Grant Letter (executive officers) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed April 1, 2005)
10.26**	—	Form of LTIP Grant Letter (independent directors) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed February 23, 2005)
10.27**	—	Form of LTIP Grant Letter (designated directors) (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed February 23, 2005)
10.28**	—	Form of LTIP Grant Letter (payment to entity) (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K filed February 23, 2005)
10.29**	—	Form of Option Grant Letter (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed April 1, 2005)
10.30	—	Administrative Services Agreement between Plains All American Pipeline Company and Vulcan Energy Corporation, dated October 14, 2005 (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed October 19, 2005)
10.31	—	Amended and Restated Limited Liability Company Agreement of PAA/Vulcan Gas Storage, LLC, dated September 13, 2005 (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed September 19, 2005)
10.32	—	Membership Interest Purchase Agreement by and between Sempra Energy Trading Corp. and PAA/Vulcan Gas Storage, LLC, dated August 19, 2005 (incorporated by reference to Exhibit 1.2 to the Current Report on Form 8-K filed September 19, 2005)
10.33**	—	Waiver Agreement dated as of August 12, 2005 between Plains All American GP LLC and Greg L. Armstrong (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 16, 2005)
10.34**	—	Waiver Agreement dated as of August 12, 2005 between Plains All American GP LLC and Harry N. Pefanis (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed August 16, 2005)
10.35	—	Excess Voting Rights Agreement dated as of August 12, 2005 between Vulcan Energy GP Holdings Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed August 16, 2005)

10.36	—	Excess Voting Rights Agreement dated as of August 12, 2005 between Lynx Holdings I, LLC and Plains All American GP LLC (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed August 16, 2005)
10.37	—	First Amendment dated as of April 20, 2005 to Restated Credit Agreement, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders

		party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed April 21, 2005)
10.38	—	Second Amendment dated as of May 20, 2005 to Restated Credit Agreement, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed May 12, 2005)
10.39**+	—	Form of LTIP Grant Letter (executive officers)
10.40**+	—	Employment Agreement between Plains All American GP LLC and John vonBerg dated December 18, 2001
10.41+	—	Third Amendment dated as of November 4, 2005 to Restated Credit Agreement, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto
21.1+	—	List of Subsidiaries of Plains All American Pipeline, L.P.
23.1+	—	Consent of PricewaterhouseCoopers LLP
31.1+	—	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a)
31.2+	—	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a)
32.1+	—	Certification of Principal Executive Officer pursuant to 18 USC 1350
32.2+	—	Certification of Principal Financial Officer pursuant to 18 USC 1350

\+ Filed herewith

** Management compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PLAINS ALL AMERICAN PIPELINE, L.P.

By: PLAINS AAP, L.P.,
its general partner

By: PLAINS ALL AMERICAN GP LLC,
its general partner

March 2, 2006

By: /s/ GREG L. ARMSTRONG
Greg L. Armstrong,
Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)

March 2, 2006

By: /s/ PHILLIP D. KRAMER
Phillip D. Kramer,
Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Name	Title	Date
/s/ GREG L. ARMSTRONG **Greg L. Armstrong**	Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)	March 2, 2006

/s/ HARRY N. PEFANIS **Harry N. Pefanis**	President and Chief Operating Officer of Plains All American GP LLC	March 2, 2006
/s/ PHILLIP D. KRAMER **Phillip D. Kramer**	Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)	March 2, 2006
/s/ TINA L. VAL **Tina L. Val**	Vice President—Accounting and Chief Accounting Officer of Plains All American GP LLC (Principal Accounting Officer)	March 2, 2006
/s/ EVERARDO GOYANES **Everardo Goyanes**	Director of Plains All American GP LLC	March 2, 2006
/s/ GARY R. PETERSEN **Gary R. Petersen**	Director of Plains All American GP LLC	March 2, 2006
/s/ ROBERT V. SINNOTT **Robert V. Sinnott**	Director of Plains All American GP LLC	March 2, 2006
/s/ DAVID N. CAPOBIANCO **David N. Capobianco**	Director of Plains All American GP LLC	March 2, 2006
/s/ ARTHUR L. SMITH **Arthur L. Smith**	Director of Plains All American GP LLC	March 2, 2006
/s/ J. TAFT SYMONDS **J. Taft Symonds**	Director of Plains All American GP LLC	March 2, 2006

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Plains All American Pipeline, L.P.'s management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Management has used the framework set forth in the report entitled “Internal Control—Integrated Framework” published by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”) to evaluate the effectiveness of the Partnership’s internal control over financial reporting. Based on that evaluation, management has concluded that the Partnership’s internal control over financial reporting was effective as of December 31, 2005. Management’s assessment of the effectiveness of the Partnership’s internal control over financial reporting as of December 31, 2005 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

/s/ GREG L. ARMSTRONG

Greg L. Armstrong,
Chairman of the Board, Chief Executive Officer and
Director of Plains All American GP LLC
(Principal Executive Officer)

/s/ PHILLIP D. KRAMER

Phillip D. Kramer
Executive Vice President and
Chief Financial Officer of Plains All American GP LLC
(Principal Financial Officer)

March 2, 2006

Report of Independent Registered Public Accounting Firm

To the Board of Directors of the General Partner and Unitholders of
Plains All American Pipeline, L.P.:

We have completed integrated audits of Plains All American Pipeline, L.P.’s 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of cash flows, of changes in partners’ capital, of comprehensive income and of changes in accumulated other comprehensive income present fairly, in all material respects, the financial position of Plains All American Pipeline, L.P. and its subsidiaries at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Partnership changed its method of accounting for pipeline linefill in third party assets effective January 1, 2004.

Internal control over financial reporting

Also, in our opinion, management’s assessment, included in the accompanying Management’s Report on Internal Control Over Financial Reporting, that the Partnership maintained effective internal control over financial reporting as of December 31, 2005 based on criteria established in Internal Control- Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control- Integrated Framework issued by the COSO. The Partnership’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management’s assessment and on the effectiveness of the Partnership’s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management’s assessment, testing and evaluating the design and operating effectiveness of internal control, and

performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate

PricewaterhouseCoopers LLP

Houston, Texas
March 2, 2006

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in millions, except units)

	December 31, 2005	December 31, 2004
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 9.6	$ 13.0
Trade accounts receivable and other receivables, net	781.0	521.8
Inventory	910.3	498.2
Other current assets	104.3	68.2
Total current assets	1,805.2	1,101.2
PROPERTY AND EQUIPMENT	2,116.1	1,911.5
Accumulated depreciation	(258.9)	(183.9)
	1,857.2	1,727.6
OTHER ASSETS		
Pipeline linefill in owned assets	180.2	168.4
Inventory in third party assets	71.5	59.3
Investment in PAA/Vulcan Gas Storage, LLC	113.5	—
Other, net	92.7	103.9
Total assets	$ 4,120.3	$ 3,160.4
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable	$ 1,293.6	$ 850.9
Due to related parties	6.8	32.9
Short-term debt	378.4	175.5
Other current liabilities	114.5	54.4
Total current liabilities	1,793.3	1,113.7
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	4.7	151.7
Senior notes, net of unamortized discount of $3.1 and $2.7, respectively	947.0	797.3
Other long-term liabilities and deferred credits	44.6	27.5
Total liabilities	2,789.6	2,090.2
COMMITMENTS AND CONTINGENCIES (NOTE 10)		
PARTNERS' CAPITAL		
Common unitholders (73,768,576 and 62,740,218 units outstanding at December 31, 2005, and December 31, 2004, respectively)	1,294.1	919.8
Class B common unitholder (1,307,190 units outstanding at December 31, 2004)	—	18.8
Class C common unitholders (3,245,700 units outstanding at December 31, 2004)	—	100.4
General partner	36.6	31.2
Total partners' capital	1,330.7	1,070.2
	$ 4,120.3	$ 3,160.4

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Twelve Months Ended December 31,		
	2005	2004	2003
REVENUES			
Crude oil and LPG sales (includes approximately $16,077.8, $11,247.0, $6,124.9, respectively, related to buy/sell transactions, see Note 2)	$ 30,139.7	$ 20,184.3	$ 11,952.6
Other gathering, marketing, terminalling and storage revenues	46.0	38.4	32.1
Pipeline margin activities revenues (includes approximately $197.1, $149.8, and $166.2, respectively, related to buy/sell transactions, see Note 2)	772.7	575.2	505.3
Pipeline tariff activities revenues	218.9	177.6	99.9
Total revenues	31,177.3	20,975.5	12,589.9
COSTS AND EXPENSES			
Crude oil and LPG purchases and related costs (includes approximately $15,910.3, $11,137.7 and $5,967.2, respectively, related to buy/sell transactions, see Note 2)	29,691.9	19,870.9	11,746.4
Pipeline margin activities purchases (includes approximately $196.2, $142.5 and $159.2, respectively, related to buy/sell transactions, see Note 2)	750.6	553.7	486.1
Field operating costs (excluding Long-Term Incentive Plan (“LTIP”) charge)	269.4	218.6	134.2
LTIP charge—operations	3.1	0.9	5.7
General and administrative expenses (excluding LTIP charge)	80.2	75.7	50.0
LTIP charge—general and administrative	23.0	7.0	23.1
Depreciation and amortization	83.5	68.7	46.2
Total costs and expenses	30,901.7	20,795.5	12,491.7
OPERATING INCOME	275.6	180.0	98.2
OTHER INCOME/(EXPENSE)			
Equity earnings in PAA/Vulcan Gas Storage, LLC.	1.0	—	—
Interest expense (net of capitalized interest of $1.8, $0.5, and $0.5)	(59.4)	(46.7)	(35.2)
Interest and other income (expense), net	0.6	(0.2)	(3.6)
Income before cumulative effect of change in accounting principle	217.8	133.1	59.4
Cumulative effect of change in accounting principle	—	(3.1)	—
NET INCOME	$ 217.8	$ 130.0	$ 59.4
NET INCOME-LIMITED PARTNERS	$ 198.8	$ 119.3	$ 53.4
NET INCOME-GENERAL PARTNER	$ 19.0	$ 10.7	$ 6.0
BASIC NET INCOME PER LIMITED PARTNER UNIT			
Income before cumulative effect of change in accounting principle	$ 2.77	$ 1.94	$ 1.01
Cumulative effect of change in accounting principle	—	(0.05)	—
Net income	$ 2.77	$ 1.89	$ 1.01
DILUTED NET INCOME PER LIMITED PARTNER UNIT			
Income before cumulative effect of change in accounting principle	$ 2.72	$ 1.94	$ 1.00
Cumulative effect of change in accounting principle	—	(0.05)	—
Net income	$ 2.72	$ 1.89	$ 1.00
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	69.3	63.3	52.7
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	70.5	63.3	53.4

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Year Ended December 31,		
	2005	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 217.8	$ 130.0	$ 59.4
Adjustments to reconcile to cash flows from operating activities:			
Depreciation and amortization	83.5	68.7	46.2
Cumulative effect of change in accounting principle	—	3.1	—
Inventory valuation adjustment	—	2.0	—
SFAS 133 mark-to-market adjustment	18.9	(1.0)	(0.4)
LTIP charge	26.1	7.9	28.8
Noncash amortization of terminated interest rate hedging instruments	1.6	1.5	—
(Gain)/loss on foreign currency revaluation	2.1	(5.0)	—
Net cash paid for terminated interest rate hedging instruments	(0.9)	(1.5)	(6.2)
Equity earnings in PAA/Vulcan Gas Storage, LLC	(1.0)	—	—
Changes in assets and liabilities, net of acquisitions:			
Trade accounts receivable and other	(299.2)	(29.2)	(98.3)
Inventory	(425.1)	(398.7)	(38.9)
Accounts payable and other current liabilities	427.8	327.5	121.3
Inventory in third party assets	—	(7.2)	—
Due to related parties	(27.5)	5.9	3.4
Net cash provided by operating activities	24.1	104.0	115.3
CASH FLOWS FROM INVESTING ACTIVITIES			

Cash paid in connection with acquisitions	(30.0)	(535.3)	(168.4)
Additions to property and equipment	(164.1)	(116.9)	(65.4)
Investment in PAA/Vulcan Gas Storage, LLC	(112.5)	—	—
Cash paid for linefill in assets owned	—	(2.0)	(46.8)
Proceeds from sales of assets	9.4	3.0	8.5
Net cash used in investing activities	(297.2)	(651.2)	(272.1)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings/(repayments) on long-term revolving credit facility	(143.7)	64.9	62.5
Net borrowings on working capital revolving credit facility	67.2	62.9	25.3
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility	138.9	(20.1)	(6.2)
Principal payments on senior secured term loans	—	—	(297.0)
Proceeds from the issuance of senior notes	149.3	348.1	249.3
Net proceeds from the issuance of common units	264.2	262.1	250.3
Distributions paid to unitholders and general partner	(197.0)	(158.4)	(121.8)
Other financing activities	(8.3)	(5.0)	(5.2)
Net cash provided by financing activities	270.6	554.5	157.2
Effect of translation adjustment on cash	(0.9)	1.6	0.2
Net increase/(decrease) in cash and cash equivalents	(3.4)	8.9	0.6
Cash and cash equivalents, beginning of period	13.0	4.1	3.5
Cash and cash equivalents, end of period	$ 9.6	$ 13.0	$ 4.1
Cash paid for interest, net of amounts capitalized	$ 80.4	$ 40.8	$ 36.4

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL

(in millions)

	Common Units		Class B Common Units		Class C Common Units		Subordinated Units		General Partner	Total	Total Partners' Capital
	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Amount	Units	Amount
Balance at December 31, 2002	38.3	$ 524.4	1.3	$ 18.5	—	$ —	10.0	$ (47.1)	$ 15.8	49.6	$ 511.6
Net income	—	41.3	—	1.3	—	—	—	10.8	6.0	—	59.4
Distributions	—	(89.8)	—	(2.9)	—	—	—	(21.9)	(7.2)	—	(121.8)
Issuance of common units	8.7	245.1	—	—	—	—	—	—	5.2	8.7	250.3
Issuance of common units under LTIP	—	0.6	—	—	—	—	—	—	—	—	0.6
Conversion of subordinated units	2.5	(9.8)	—	—	—	—	(2.5)	9.8	—	—	—
Other comprensive income	—	32.3	—	1.1	—	—	—	8.5	4.7	—	46.6
Balance at December 31, 2003	**49.5**	**$ 744.1**	**1.3**	**$ 18.0**	**—**	**$ —**	**7.5**	**$ (39.9)**	**$ 24.5**	**58.3**	**$ 746.7**
Net income	—	111.1	—	2.5	—	4.2	—	1.5	10.7	—	130.0
Distributions	—	(134.2)	—	(3.0)	—	(5.7)	—	(4.2)	(11.3)	—	(158.4)
Issuance of common units	5.0	157.5	—	—	—	—	—	—	3.4	5.0	160.9
Issuance of common units under LTIP	0.4	11.8	—	—	—	—	—	—	0.2	0.4	12.0
Issuance of units for acquisition contingent consideration	0.4	13.1	—	—	—	—	—	—	0.3	0.4	13.4
Private placement of Class C common units	—	—	—	—	3.2	98.8	—	—	2.1	3.2	100.9
Other comprehensive income	—	59.9	—	1.3	—	3.1	—	(0.9)	1.3	—	64.7
Conversion of subordinated units	7.5	(43.5)	—	—	—	—	(7.5)	43.5	—	—	—
Balance at December 31, 2004	**62.8**	**$ 919.8**	**1.3**	**$ 18.8**	**3.2**	**$ 100.4**	**—**	**$ —**	**$ 31.2**	**67.3**	**$ 1,070.2**
Net income	—	196.9	—	0.5	—	1.4	—	—	19.0	—	217.8
Distributions	—	(175.6)	—	(0.8)	—	(2.0)	—	—	(18.6)	—	(197.0)
Issuance of common units	6.5	258.7	—	—	—	—	—	—	5.5	6.5	264.2
Issuance of common units under LTIP	—	1.9	—	—	—	—	—	—	—	—	1.9
Conversion of Class B units	1.3	18.3	(1.3)	(18.3)	—	—	—	—	—	—	—
Conversion of Class C units	3.2	99.3	—	—	(3.2)	(99.3)	—	—	—	—	—
Other comprehensive loss		(25.2)		(0.2)		(0.5)	—	—	(0.5)	—	(26.4)
Balance at December 31, 2005	**73.8**	**$ 1,294.1**	**—**	**$ —**	**—**	**$ —**	**—**	**$ —**	**$ 36.6**	**73.8**	**$ 1,330.7**

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Twelve Months Ended December 31,

	2005	2004	2003
		(in millions)	
Net income	$ 217.8	$ 130.0	$ 59.4
Other comprehensive income/(loss)	(26.4)	64.7	46.6
Comprehensive income	$ 191.4	$ 194.7	$ 106.0

CONSOLIDATED STATEMENTS OF CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

	Net Deferred Gain/(Loss) on Derivative Instruments	Currency Translation Adjustments	Total
		(in millions)	
Balance at December 31, 2002	$ (8.2)	$ (6.2)	$ (14.4)
Reclassification adjustments for settled contracts	(28.2)	—	(28.2)
Changes in fair value of outstanding hedge positions	28.7	—	28.7
Currency translation adjustment	—	46.1	46.1
2003 Activity	0.5	46.1	46.6
Balance at December 31, 2003	$ (7.7)	$ 39.9	$ 32.2
Reclassification adjustments for settled contracts	13.2	—	13.2
Changes in fair value of outstanding hedge positions	20.4	—	20.4
Currency translation adjustment	—	31.1	31.1
2004 Activity	33.6	31.1	64.7
Balance at December 31, 2004	$ 25.9	$ 71.0	$ 96.9
Reclassification adjustments for settled contracts	117.4	—	117.4
Changes in fair value of outstanding hedge positions	(159.9)	—	(159.9)
Currency translation adjustment	—	16.1	16.1
2005 Activity	(42.5)	16.1	(26.4)
Balance at December 31, 2005	$ (16.6)	$ 87.1	$ 70.5

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization and Basis of Presentation

Organization

Plains All American Pipeline, L.P. (“PAA”) is a Delaware limited partnership formed in September of 1998. Our operations are conducted directly and indirectly through our primary operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P. We are engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other natural gas related petroleum products. We refer to liquefied petroleum gas and natural gas related petroleum products collectively as “LPG.” We own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins, transportation corridors and at major market hubs in the United States and Canada. In addition, through our 50% equity ownership in PAA/Vulcan Gas Storage, LLC (“PAA/Vulcan”), we are engaged in the development and operation of natural gas storage facilities.

Our 2% general partner interest is held by Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P.’s general partner. Plains All American GP LLC manages our operations and activities and employs our domestic officers and personnel. Our Canadian officers and employees are employed by PMC (Nova Scotia) Company, the general partner of Plains Marketing Canada, L.P. Unless the context otherwise requires, we use the term “general partner” to refer to both Plains AAP, L.P. and Plains All American GP LLC. Plains AAP, L.P. and Plains All American GP LLC are essentially held by seven owners with interests ranging from 54.3% to 1.2%. Also, see Note 8 for a description of the reallocation of the General Partnership interest.

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2005 and 2004, and the consolidated results of our operations, cash flows, changes in partners’ capital, comprehensive income and changes in accumulated other comprehensive income for the years ended December 31, 2005, 2004 and 2003. All significant intercompany transactions have been eliminated. Certain reclassifications have been made to the previous years to conform to the 2005 presentation of the financial statements. These reclassifications do not affect net income. The accompanying consolidated financial statements of PAA include PAA and all of its wholly-owned subsidiaries. Investments in 50% or less owned affiliates, over which we have significant influence, are accounted for by the equity method.

Change in Accounting Principle

During the second quarter of 2004, we changed our method of accounting for pipeline linefill in third party assets. Historically, we viewed pipeline linefill, whether in our assets or third party assets, as having long-term characteristics rather than characteristics typically associated with the short-term classification of operating inventory. Therefore, previously we did not include linefill barrels in the same average costing calculation as our operating inventory, but instead carried linefill at historical cost. Following this change in accounting principle, the linefill in third party assets that we historically classified as a portion of "Pipeline Linefill" on the face of the balance sheet (a long-term asset) and carried at historical cost, is included in "Inventory" (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we reclassify the linefill in third party assets not expected to be liquidated within the succeeding twelve months out of "Inventory" (a

current asset), at average cost, and into "Inventory in Third Party Assets" (a long-term asset), which is now reflected as a separate line item on the consolidated balance sheet.

This change in accounting principle is effective January 1, 2004 and is reflected in the consolidated statement of operations for the year ended December 31, 2004 and the consolidated balance sheets as of December 31, 2004. The cumulative effect of this change in accounting principle as of January 1, 2004, is a charge of approximately $3.1 million, representing a reduction in Inventory of approximately $1.7 million, a reduction in Pipeline Linefill of approximately $30.3 million and an increase in Inventory in Third Party Assets of $28.9 million. The pro forma impact for the year ended December 31, 2003 would have been an increase to net income of approximately $2.0 million ($0.04 per basic and diluted limited partner unit) resulting in pro forma net income of $61.5 million and pro forma basic net income per limited partner unit of $1.05 and pro forma diluted net income per limited partner unit of $1.04.

Note 2—Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates we make include: (i) accruals related to purchases and sales, (ii) mark-to-market estimates pursuant to Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting For Derivative Instruments and Hedging Activities", as amended, ("SFAS 133") (iii) contingent liability accruals, (iv) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets and (v) accruals related to our Long-Term Incentive Plans. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Revenue Recognition

Gathering, Marketing, Terminalling and Storage Segment Revenues. Revenues from crude oil and LPG sales are recognized at the time title to the product sold transfers to the purchaser, which occurs upon delivery of the product to the purchaser or its designee. Sales of crude oil and LPG consist of outright sales contracts and buy/sell arrangements, which are booked gross, as well as barrel exchanges, which are booked net. See "—Recent Accounting Pronouncements" below.

Terminalling and storage revenues, which are classified as other GMT&S revenues on the income statement, consist of (i) storage fees from actual storage used on a month-to-month basis; (ii) storage fees resulting from short-term and long-term contracts for committed space that may or may not be utilized by the customer in a given month; and (iii) terminal throughput charges to pump crude oil to connecting carriers. Revenues on storage are recognized ratably over the term of the contract. Terminal throughput charges are recognized as the crude oil exits the terminal and is delivered to the connecting crude oil carrier or third party terminal. Any throughput volumes in transit at the end of a given month are treated as third party inventory and do not incur storage fees. All terminalling and storage revenues are based on actual volumes and rates.

Pipeline Segment Revenues. Pipeline margin activities primarily consist of the purchase and sale of crude oil shipped on our San Joaquin Valley system from barrel exchanges and buy/sell arrangements. Revenues associated with these activities are recognized at the time title to the product sold transfers to the purchaser, which occurs upon delivery of the product to the purchaser or its designee. Revenues for these transactions are recorded gross except in the case of barrel exchanges that are net settled. All of our pipeline margin activities revenues are based on actual volumes and prices. Revenues from pipeline tariffs and fees are associated with the transportation of crude oil at a published tariff as well as fees associated

with line leases for committed space on a particular system that may or may not be utilized. Tariff revenues are recognized either at the point of delivery or at the point of receipt pursuant to specifications outlined in the regulated and non-regulated tariffs. Revenues associated with line-lease fees are recognized in the month to which the lease applies, whether or not the space is actually utilized. All pipeline tariff and fee revenues are based on actual volumes and rates.

Purchases and Related Costs

Purchases and related costs include: (i) the cost of crude oil and LPG purchased in outright purchases as well as buy/sell arrangements; (ii) third party transportation and storage, whether by pipeline, truck or barge; (iii) interest cost attributable to borrowings for inventory stored in a contango market; (iv) performance related bonus accruals; and (v) expenses of issuing letters of credit to support these purchases. These purchases are accrued at the time title transfers to us, which occurs upon receipt of the product.

Operating Expenses and General and Administrative Expenses

Operating expenses consist of various field and pipeline operating expenses including fuel and power costs, telecommunications, payroll and benefit costs for truck drivers and pipeline field personnel, maintenance costs, regulatory compliance, environmental remediation, insurance, vehicle leases, and property taxes. General and administrative expenses consist primarily of payroll and benefit costs, certain information system and legal costs, office rent, contract and consultant costs, and audit and tax fees.

Foreign Currency Transactions

Assets and liabilities of subsidiaries with a functional currency other than the U.S. Dollar are translated at period end rates of exchange and revenues and expenses are translated at average exchange rates prevailing for each month. The resulting translation adjustments are made directly to a separate component of other comprehensive income in partners' capital. Gains and losses from foreign currency transactions (transactions denominated in a currency other than the entity's functional currency) are included in the consolidated statement of operations. The foreign currency transactions resulted in a loss of approximately $2.1 million and a gain of approximately $5.0 million for the years ended December 31, 2005 and 2004, respectively. There was no material gain or loss for the year ended December 31, 2003.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less and typically exceed federally insured limits. We periodically assess the financial condition of the institutions where these funds are held and believe that the credit risk is minimal.

Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of LPG. The majority of our accounts receivable relate to our gathering and marketing activities that can generally be described as high volume and low margin activities, in many cases involving exchanges of crude oil volumes. We make a determination of the amount, if any, of the line of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit, advance cash payments or "parental" guarantees. At December 31, 2005 and 2004, we had received approximately $52.5 million and $20.3 million, respectively, of advance cash payments and prepayments from third parties

to mitigate credit risk. In addition, we enter into netting arrangements with our counterparties. These arrangements cover a significant part of our transactions and also serve to mitigate credit risk.

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted. At December 31, 2005 and 2004, substantially all of our net accounts receivable classified as current were less than 60 days past their scheduled invoice date, and our allowance for doubtful accounts receivable (the entire balance of which is classified as current) totaled $0.8 million and $0.6 million, respectively. Although we consider our allowance for doubtful trade accounts receivable to be adequate, there is no assurance that actual amounts will not vary significantly from estimated amounts. Following is a reconciliation of the changes in our allowance for doubtful accounts balances (in millions):

	December 31,		
	2005	2004	2003
Balance at beginning of year	$ 0.6	$ 0.2	$ 8.1
Applied to accounts receivable balances	(0.7)	—	(8.3)
Charged to expense	0.9	0.4	0.4
Balance at end of year	$ 0.8	$ 0.6	$ 0.2

Inventory and Pipeline Linefill

Inventory primarily consists of crude oil and LPG in pipelines, storage tanks and rail cars that is valued at the lower of cost or market, with cost determined using an average cost method. During the fourth quarter of 2004, we recorded a $2.0 million noncash charge related to the writedown of our LPG inventory. Linefill and minimum working inventory requirements are recorded at historical cost and consist of crude oil and LPG used to pack an operated pipeline such that when an incremental barrel enters a pipeline it forces a barrel out at another location, as well as the minimum amount of crude oil necessary to operate our storage and terminalling facilities.

Linefill and minimum working inventory requirements in third party assets are included in "Inventory" (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we reclassify the linefill in third party assets not expected to be liquidated within the succeeding twelve months out of "Inventory," at average cost, and into "Inventory in Third Party Assets" (a long-term asset), which is reflected as a separate line item within other assets on the consolidated balance sheet.

At December 31, 2005 and 2004, inventory and linefill consisted of:

	December 31, 2005			December 31, 2004		
	Barrels	Dollars	Dollar/ barrel	Barrels	Dollars	Dollar/ barrel
	(Barrels in thousands and dollars in millions)					
Inventory[(1)]						
Crude oil	13,887	$ 755.7	$ 54.42	8,716	$ 396.2	$ 45.46
LPG	3,649	149.0	$ 40.83	2,857	100.1	$ 35.04
Parts and supplies	N/A	5.6	N/A	N/A	1.9	N/A
Inventory subtotal	17,536	910.3		11,573	498.2	
Inventory in third party assets						
Crude oil	1,248	58.6	$ 46.96	1,294	48.7	$ 37.64
LPG	318	12.9	$ 40.57	318	10.6	$ 33.33
Inventory in third party assets subtotal	1,566	71.5		1,612	59.3	
Linefill						
Crude oil linefill	6,207	179.3	$ 28.89	6,015	168.4	$ 28.00
LPG linefill	27	0.9	$ 33.33	—	—	N/A
Linefill subtotal	6,234	180.2		6,015	168.4	

Total	25,336	$ 1,162.0	19,200	$ 725.9

(1) Dollars per barrel include the impact of inventory hedges on a portion of our volumes.

Property and Equipment

Property and equipment, net is stated at cost and consisted of the following:

	Estimated Useful Lives (Years)	December 31, 2005	2004
		(in millions)	
Crude oil pipelines and facilities	30 - 40	$ 1,739.5	$ 1,605.3
Crude oil and LPG storage and terminal facilities	30 - 40	214.6	169.6
Trucking equipment and other	5 - 15	137.1	117.6
Office property and equipment	3 - 5	24.9	19.0
		2,116.1	1,911.5
Less accumulated depreciation		(258.9)	(183.9)
Property and equipment, net		$ 1,857.2	$ 1,727.6

Depreciation expense for each of the three years in the period ended December 31, 2005 was $79.2 million, $64.8 million and $41.8 million, respectively.

We calculate our depreciation using the straight-line method, based on estimated useful lives and salvage values of our assets. These estimates are based on various factors including age (in the case of acquired assets), manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions, and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives and salvage values that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization. Historically, adjustments to useful lives have not had a material impact on our aggregate depreciation levels from year to year. Also,

gains/losses on sales of assets and asset impairments are included as a component of depreciation and amortization in the consolidated statements of operations.

In accordance with our capitalization policy, costs associated with acquisitions and improvements that expand our existing capacity, including related interest costs, are capitalized. For the years ended December 31, 2005, 2004 and 2003, capitalized interest was $1.8 million, $0.5 million and $0.5 million, respectively. In addition, costs required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives are capitalized and classified as maintenance capital. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred.

Asset Retirement Obligation

In June 2001, the FASB issued SFAS No. 143 “Accounting for Asset Retirement Obligations.” SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including (1) the time of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. SFAS 143 requires that the cost for asset retirement should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. Effective January 1, 2003, we adopted SFAS 143, as required. The adoption of this statement did not have a material impact on our financial position, results of operations or cash flows.

Some of our assets, primarily related to our pipeline operations segment, have obligations to perform remediation and, in some instances, removal activities when the asset is abandoned. However, the majority of these obligations are associated with active assets and the fair value of the asset retirement obligations cannot be reasonably estimated, as the settlement dates are indeterminate. A small portion of these obligations relate to assets that are inactive or that we plan to take out of service and although the ultimate timing and cost to settle these obligations are not known with certainty, we can reasonably estimate the obligation. We have estimated that the fair value of these obligations is approximately $4.6 million and $2.5 million at December 31, 2005 and 2004, respectively. For those obligations that are currently indeterminate, we will record asset retirement obligations in the period in which we can reasonably determine the settlement dates.

Impairment of Long-Lived Assets

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written-down to estimated fair value in accordance with SFAS No. 144 “Accounting for the Impairment or Disposal of Long-Lived Assets,” as amended. Under SFAS 144, an asset shall be tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount the carrying value exceeds the fair value of the asset is recognized. Fair value is generally determined from estimated discounted future net cash flows. We adopted SFAS 144 on January 1, 2002. There were no asset impairments in 2005 or 2003. In 2004, we recognized a charge of approximately $2.0 million associated with taking our pipeline in the Illinois Basin out of service. The amount of the impairment represented the remaining net book value of the idled pipeline system and is included as a component of depreciation and amortization in the consolidated statements of operations. This pipeline did not support spending the capital necessary to continue service and we shifted the majority of the gathering and transport activities to trucks.

Other, net

Other assets net of accumulated amortization consist of the following:

	December 31, 2005	December 31, 2004
	(in millions)	
Goodwill	$ 47.4	$ 47.1
Deposit on pending acquisition	—	11.9
Debt issue costs	17.4	15.5
Other investment in unconsolidated affiliate	8.2	8.2
Fair value of derivative instruments	5.5	8.6
Intangible assets (contracts)	2.8	2.7
Other	18.5	14.0
	99.8	108.0
Less accumulated amortization	(7.1)	(4.1)
	$ 92.7	$ 103.9

In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets," we test goodwill and other intangible assets periodically to determine whether an impairment has occurred. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not impaired. An impairment loss is recognized for intangibles if the carrying amount of an intangible asset is not recoverable and its carrying amount exceeds its fair value. As of December 31, 2005 and 2004, substantially all of our goodwill is allocated to our gathering, marketing, terminalling and storage operations ("GMT&S"). Since adoption of SFAS 142, we have not recognized any impairment of goodwill.

Costs incurred in connection with the issuance of long-term debt and amendments to our credit facilities are capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the "effective interest" method of amortization. Fully amortized debt issue costs and the related accumulated amortization are written off in conjunction with the refinancing or termination of the applicable debt arrangement. We capitalized costs of approximately $3.3 million, $5.9 million and $5.1 million in 2005, 2004 and 2003, respectively. In addition, during 2005 we wrote off approximately $1.4 million of fully amortized costs and the related accumulated amortization. During 2004 and 2003, we wrote off unamortized costs totaling approximately $0.7 million and $3.3 million.

Amortization of other assets for each of the three years in the period ended December 31, 2005, was $4.3 million, $3.9 million and $4.4 million, respectively.

Environmental Matters

We record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We also record receivables for amounts recoverable from insurance or from third parties under indemnification agreements in the period that we determine the costs are probable of recovery.

We expense or capitalize, as appropriate, environmental expenditures. We expense expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation. We capitalize environmental liabilities assumed in business combinations based on the fair value of the environmental obligations caused by past operations of the acquired company.

Income and Other Taxes

Except as noted below, no provision for U.S. federal or Canadian income taxes related to our operations is included in the accompanying consolidated financial statements, because as a partnership we

are not subject to federal, state or provincial income tax and the tax effect of our activities accrues to the unitholders. Net earnings for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the partnership agreement. Individual unitholders will have different investment bases depending upon the timing and price of acquisition of partnership units. Further, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, may differ from the accounting followed in the consolidated financial statements. Accordingly, there could be significant differences between each individual unitholder's tax bases and the unitholder's share of the net assets reported in the consolidated financial statements. We do not have access to information about each individual unitholder's tax attributes, and the aggregate tax basis cannot be readily determined. Accordingly, we do not believe that in our circumstance, the aggregate difference would be meaningful information.

The Partnership's Canadian operations are conducted through an operating limited partnership, of which our wholly owned subsidiary PMC (Nova Scotia) Company is the general partner. For Canadian tax purposes, the general partner is taxed as a corporation, subject to income taxes and a capital -based tax at federal and provincial levels. For the years presented, these amounts were immaterial.

In addition to federal income taxes, owners of our common units may be subject to other taxes, such as state and local and Canadian federal and provincial taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property. A unitholder may be required to file Canadian federal income tax returns, pay Canadian federal and provincial income taxes, file state income tax returns and pay taxes in various states.

Recent Accounting Pronouncements

In June 2005, the Emerging Issues Task Force issued Issue No. 04-05 ("EITF 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." EITF 04-05 provides guidance in determining whether a general partner controls a limited partnership by determining the limited partners' substantive ability to dissolve (liquidate) the limited partnership as well as assessing the substantive participating rights of the limited partners within the limited partnership. EITF 04-05 states that if the limited partners do not have substantive ability to dissolve (liquidate) or have substantive participating rights then the general partner is presumed to control that partnership and would be required to consolidate the limited partnership. This EITF is effective in fiscal periods beginning after December 15, 2005. Although this EITF does not directly impact us, it does impact our general partner. Our general partner will adopt this standard prospectively beginning January, 1, 2006. The adoption of this standard will result in the consolidation of our results of operations and balance sheet in their consolidated financial statements.

In December 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123(R) (revised 2004), "Share-Based Payment." This statement 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 all share-based payment transactions be recognized in the financial statements at fair value. In April 2005, both the FASB and the Securities and Exchange Commission decided to delay the effective date for public companies to implement SFAS No. 123(R). The new statement is now effective for public companies for annual periods beginning after June 15, 2005. Following our general partner's adoption of EITF 04-05, we will be a part of the same consolidated group and thus SFAS 123(R) will be applicable to our general partner's long-term incentive plan. Our general partner has historically followed a cash plan probability model in accounting for its long-term incentive plans and will use the modified prospective application, as defined in SFAS 123(R), to adopt this standard. Under SFAS 123(R), the obligation will be recorded at fair value. We reimburse our general partner for all direct and indirect costs of services provided, including the costs

of employees and officers (See Note 8 "Related Party Transactions"), and thus the calculation of our obligation related to our general partner's long-term incentive plan has been consistent with the methodology that they have historically used. Upon measuring the obligation at fair value under SFAS 123(R), we estimate that our obligation for outstanding awards as of January 1, 2006 will be reduced by approximately $6.4 million, which will be recorded as a cumulative effect of change in accounting principle in our consolidated statements of operations in 2006.

In September 2005, the Emerging Issues Task Force issued Issue No. 04-13 ("EITF 04-13"), "Accounting for Purchases and Sales of Inventory with the Same Counterparty." The EITF concluded that 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 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 will be effective in reporting periods beginning after March 15, 2006. The adoption of EITF 04-13 will cause inventory purchases and sales under buy/sell transactions, which were recorded gross as purchases and sales, to be treated as inventory exchanges in our consolidated statement of operations. We have parenthetically disclosed buy/sell transactions in our consolidated statements of operations. EITF 04-13 will reduce gross revenues and purchases, but is not expected to have a material impact on our financial position, net income, or liquidity. The treatment of buy/sell transactions under EITF 04-13 will reduce the relative amount of revenues on our income statement.

In 2005, the FASB issued Interpretation No. 47 ("FIN 47"), "Accounting for Conditional Asset Retirement Obligations," which is an interpretation of SFAS 143. FIN 47 defines a conditional asset retirement obligation ("ARO") as a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional upon future events that may or may not be within the control of the entity. An entity is required to recognize a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. Uncertainty about the timing and method of settlement for a conditional ARO should be considered in estimating the ARO when sufficient information exists. This Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO. We adopted FIN 47 on December 31, 2005, and the adoption did not have a material impact on our consolidated financial position or results of operations.

Derivative Instruments and Hedging Activities

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled trading program, (iii) manage our exposure to interest rate risk and (iv) manage our exposure to currency exchange rate risk. We record all derivative instruments on the balance sheet as either assets or liabilities measured at their fair value under the provisions of SFAS 133. SFAS 133 requires that changes in derivative instruments fair value be recognized currently in earnings unless specific hedge accounting criteria are met, in which case, changes in fair value are deferred to Other Comprehensive Income ("OCI") and reclassified into earnings when the underlying transaction affects earnings. Accordingly, changes in fair value are included in the current period for (i) derivatives characterized as fair value hedges, (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items.

Net Income Per Unit

Except as discussed in the following paragraph, basic and diluted net income per limited partner unit is determined by dividing net income after deducting the amount allocated to the general partner interest, (including its incentive distribution in excess of its 2% interest), by the weighted average number of outstanding limited partner units during the period. Subject to applicability of Emerging Issues Task Force Issue No. 03-06 ("EITF 03-06''), "Participating Securities and the Two-Class Method under FASB

Statement No. 128,'' as discussed below, Partnership income is first allocated to the general partner based on the amount of incentive distributions. The remainder is then allocated between the limited partners and general partner based on percentage ownership in the Partnership.

EITF 03-06 addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock. Essentially, EITF 03-06 provides that in any accounting period where our aggregate net income exceeds our aggregate distribution for such period, we are required to present earnings per unit as if all of the earnings for the periods were distributed, regardless of the pro forma nature of this allocation and whether those earnings would actually be distributed during a particular period from an economic or practical perspective. EITF 03-06 does not impact our overall net income or other financial results, however, for periods in which aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing the earnings per limited partner unit. This result occurs as a larger portion of our aggregate earnings is allocated to the incentive distribution rights held by our general partner, as if distributed, even though we make cash distributions on the basis of cash available for distributions, not earnings, in any given accounting period. In accounting periods where aggregate net income does not exceed our aggregate distributions for such period, EITF 03-06 does not have any impact on our earnings per unit calculation.

The following sets forth the computation of basic and diluted earnings per limited partner unit. The net income available to limited partners and the weighted average limited partner units outstanding have been adjusted for instruments considered common unit equivalents at 2005, 2004 and 2003.

	Year ended December 31,		
	2005	2004	2003
	(in millions, except per unit data)		
Numerator for basic and diluted earnings per limited partner unit:			
Net income	$ 217.8	$ 130.0	$ 59.4

Less:			
General partner's incentive distribution paid	(14.9)	(8.3)	(4.8)
Subtotal	202.9	121.7	54.6
General partner 2% ownership	(4.1)	(2.4)	(1.1)
Net income available to limited partners	198.8	119.3	53.5
Increase in general partner's incentive distribution-contingent equity issuance	—	—	(0.1)
Pro forma additional general partner's incentive distribution	(7.2)	—	—
Net income available to limited partners under EITF 03-06	$ 191.6	$ 119.3	$ 53.4
Denominator:			
Denominator for basic earnings per limited partner unit-weighted average number of limited partner units	69.3	63.3	52.7
Effect of dilutive securities:			
Weighted average LTIP units (see Note 9)	1.2	—	—
Contingent equity issuance	—	—	0.7
Denominator for diluted earnings per limited partner unit-weighted average number of limited partner units	70.5	63.3	53.4
Basic net income per limited partner unit	$ 2.77	$ 1.89	$ 1.01
Diluted net income per limited partner unit	$ 2.72	$ 1.89	$ 1.00

Note 3—Acquisitions and Dispositions

The following acquisitions were accounted for using the purchase method of accounting and the purchase price was allocated in accordance with such method.

Significant Acquisitions

Link Energy LLC

On April 1, 2004, we completed the acquisition of all of the North American crude oil and pipeline operations of Link Energy LLC ("Link") for approximately $332.3 million, including $268 million of cash (net of approximately $5.5 million subsequently returned to us from an indemnity escrow account) and approximately $64 million of net liabilities assumed and acquisition-related costs. The Link crude oil business consists of approximately 7,000 miles of active crude oil pipeline and gathering systems, over 10 million barrels of active crude oil storage capacity, a fleet of approximately 200 owned or leased trucks and approximately 2 million barrels of crude oil linefill and working inventory. The Link assets complement our assets in West Texas and along the Gulf Coast and allow us to expand our presence in the Rocky Mountain and Oklahoma/Kansas regions. The results of operations and assets and liabilities from this acquisition have been included in our consolidated financial statements and in both our pipeline operations and gathering, marketing, terminalling and storage operations segments since April 1, 2004.

The purchase price was allocated as follows and includes goodwill primarily attributed to Link's gathering and marketing operations (in millions):

Cash paid for acquisition(1)	$ 268.0
Fair value of net liabilities assumed:	
Accounts receivable(2)	409.4
Other current assets	1.8
Accounts payable and accrued liabilities(2)	(459.6)
Other current liabilities	(8.5)
Other long-term liabilities	(7.4)
Total net liabilities assumed	(64.3)
Total purchase price	$ 332.3
Purchase price allocation	
Property and equipment	$ 260.2
Inventory	3.4
Linefill	55.4
Inventory in third party assets	8.1
Goodwill	5.0
Other long-term assets	0.2
Total	$ 332.3

(1) Cash paid does not include the subsequent payment of various transaction and other acquisition related costs.

(2) Accounts receivable and accounts payable are gross and do not reflect the adjustment of approximately $250 million to net settle, based on contractual agreements with our counterparties.

The total purchase price included (i) approximately $9.4 million in transaction costs, (ii) approximately $7.4 million related to a plan to terminate and relocate employees in conjunction with the acquisition, and (iii) approximately $11.0 million related to costs to terminate a contract assumed in the acquisition. These activities were substantially complete and the majority of the related costs were incurred as of December 31, 2004, resulting in total cash paid during 2004 of approximately $294 million.

The acquisition was initially funded with cash on hand, borrowings under our then existing revolving credit facilities and under a new $200 million, 364-day credit facility. In connection with the acquisition, on April 15, 2004, we completed the private placement of 3,245,700 Class C common units to a group of institutional investors. During the third quarter of 2004, we completed a public offering of common units and the sale of an aggregate of $350 million of senior notes. A portion of the proceeds from these transactions was used to retire the $200 million, 364-day credit facility.

Capline and Capwood Pipeline Systems

In March 2004, we completed the acquisition of all of Shell Pipeline Company LP's interests in two entities for approximately $158.5 million in cash (including a deposit of approximately $16 million paid in December 2003) and approximately $0.5 million of transaction and other costs. In December 2003, subsequent to the announcement of the acquisition and in anticipation of closing, we issued approximately 2.8 million common units for net proceeds of approximately $88.4 million, after paying approximately $4.1 million of transaction costs. The proceeds from this issuance were used to pay down our revolving credit facility. At closing, the cash portion of this acquisition was funded from cash on hand and borrowings under our revolving credit facility.

The principal assets of these entities are: (i) an approximate 22% undivided joint interest in the Capline Pipeline System, and (ii) an approximate 76% undivided joint interest in the Capwood Pipeline System. The Capline Pipeline System is a 633-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capwood Pipeline System is a 57-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois. The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since March 1, 2004. These pipelines provide one of the primary transportation routes for crude oil shipped into the Midwestern U.S., and delivered to several refineries and other pipelines.

The purchase price was allocated as follows (in millions):

Crude oil pipelines and facilities	$ 151.4
Crude oil storage and terminal facilities	5.7
Land	1.3
Office equipment and other	0.1
Total	$ 158.5

Other Acquisitions

2005 Acquisitions

During 2005, we completed six small transactions for aggregate consideration of approximately $40.3 million. The transactions included 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. In addition, in September 2005, PAA/Vulcan acquired Energy Center Investments LLC ("ECI"), an indirect subsidiary of Sempra Energy, for approximately $250 million. We own 50% of PAA/Vulcan and a subsidiary of Vulcan Capital owns the other 50%. See Note 8 "Related Party Transactions."

2004 Acquisitions

During 2004, in addition to the Link and Capline acquisitions, we completed several other acquisitions for aggregate consideration totaling $73.1 million including transaction costs and approximately $14.4 million of LPG operating inventory acquired. These acquisitions include crude oil mainline and gathering pipelines and propane storage facilities. The aggregate purchase price was allocated to property and equipment.

2003 Acquisitions

During 2003, we completed ten acquisitions for aggregate consideration totaling approximately $159.5 million. In addition, we accrued approximately $24.3 million of deferred purchase price related to a

2001 acquisition, which was ultimately settled with cash and units during 2004. See Note 6. The aggregate consideration for the 2003 acquisitions includes cash paid, transaction costs, assumed liabilities and estimated near-term capital costs. These acquisitions included mainline crude oil pipelines, crude oil gathering lines, terminal and storage facilities, and an underground LPG storage facility. The aggregate purchase price was allocated as follows (in millions):

Crude oil pipelines and facilities	$ 138.0
Crude oil and LPG storage facilities	7.3
Trucking equipment and other	7.8
Office property and equipment	1.2
Pipeline Linefill	4.7
Goodwill	0.5
	$ 159.5

Dispositions

During 2005, 2004 and 2003, we sold various property and equipment for proceeds totaling approximately $9.4 million, $3.0 million and $8.5 million, respectively. Losses of approximately $3.2 million were recognized in 2005 and gains of approximately $0.6 million and $0.6 million were recognized in 2004 and 2003, respectively. These gains and losses are included as a component of depreciation and amortization in the consolidated statements of operations.

Note 4—Debt

Debt consists of the following:

	December 31, 2005	December 31, 2004
	(in millions)	
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 4.8% and 3.0% at December 31, 2005 and 2004, respectively	$ 219.3	$ 80.4

Working capital borrowings, bearing interest at a rate of 5.0% and 3.7% at December 31, 2005 and 2004, respectively[(1)]	155.4	88.2
Other	3.7	6.9
Total short-term debt	378.4	175.5
Long-term debt:		
4.75% senior notes due August 2009, net of unamortized discount of $0.6 million and $0.7 million at December 31, 2005 and 2004, respectively	174.4	174.3
7.75% senior notes due October 2012, net of unamortized discount of $0.2 million and $0.3 million at December 31, 2005 and 2004, respectively	199.8	199.7
5.63% senior notes due December 2013, net of unamortized discount of $0.5 million and $0.6 million at December 31, 2005 and 2004, respectively	249.5	249.4
5.25% senior notes due June 2015, net of unamortized discount of $0.7 million at December 31, 2005.	149.3	—
5.88% senior notes due August 2016, net of unamortized discount of $1.0 million and $1.1 million at December 31, 2005 and 2004, respectively	174.0	173.9
Senior notes, net of unamortized discount[(2)]	947.0	797.3
Long-term debt under credit facilities and other—		
Senior unsecured revolving credit facility, bearing interest at 3.5% at December 31, 2004[(1)]	—	143.6
Other	4.7	8.1
Long-term debt under credit facilities and other	4.7	151.7
Total long-term debt[(1)(2)]	951.7	949.0
Total debt	$ 1,330.1	$ 1,124.5

(1) At December 31, 2005 and December 31, 2004, we have classified $155.4 million and $88.2 million, respectively, of borrowings under our senior unsecured revolving credit facility as short-term. These borrowings are designated as working capital borrowings, must be repaid within one year, and are primarily for hedged LPG and crude oil inventory and New York Mercantile Exchange ("NYMEX") margin deposits.

(2) At December 31, 2005, the aggregate fair value of our fixed-rate senior notes is estimated to be approximately $976.0 million. 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 reflect market.

Credit Facilities

In November 2005, we amended our senior unsecured credit facility to increase the aggregate capacity to $1 billion and the sub-facility for Canadian borrowings to $400 million. The amended facility can be expanded to $1.5 billion, subject to additional lender commitments, and has a final maturity of November 2010. The amended credit facility extends the maturity date and provides an additional $100 million of capacity over our previous facility. At December 31, 2005 and 2004, borrowings of approximately $155.4 million and $231.8 million, respectively, were outstanding under this facility.

Additionally, in the second quarter of 2005, we amended our senior secured hedged inventory facility to increase the capacity under the facility from $425 million to $800 million. During 2005, we extended the maturity of the senior secured hedged inventory facility by one year to November 2006. This facility is an uncommitted working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility are collateralized by the inventory purchased under the facility and the associated accounts receivable, and will be repaid with the proceeds from the sale of such inventory.

Senior Notes

During May 2005, we completed the issuance of $150 million of 5.25% senior notes due 2015. The notes were issued at 99.5% of face value. Interest payments are due on June 15 and December 15 of each year. We used the proceeds to repay amounts outstanding under our credit facilities and for general partnership purposes.

During August 2004, we completed the sale of $175 million of 4.75% senior notes due 2009 and $175 million of 5.88% senior notes due 2016. The 4.75% notes were sold at 99.6% of face value and the 5.88% notes were sold at 99.3% of face value. Interest payments are due on February 15 and August 15 of each year.

During December 2003, we completed the sale of $250 million of 5.625% senior notes due 2013. The notes were issued at 99.7% of face value. Interest payments are due on June 15 and December 15 of each year.

In each instance, the notes were co-issued by Plains All American Pipeline, L.P. and a 100% owned consolidated finance subsidiary (neither of which have independent assets or operations) and are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for subsidiaries which are not significant.

Covenants and Compliance

Our credit agreements and the indentures governing the 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 credit facility treats a change of control as an event of default and also requires us to maintain a debt coverage ratio which will not be greater than 4.75 to 1.0 on all outstanding debt and 5.25 to 1.0 on all 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.

Letters of Credit

As is customary in our industry, and in connection with our crude oil marketing, we provide certain suppliers and transporters with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. These letters of credit are issued under our credit facility, and 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, 2005 and 2004, we had outstanding letters of credit of approximately $55.5 million and $98.0 million, respectively.

Maturities

The weighted average life of our long-term debt outstanding at December 31, 2005 was approximately 7.6 years and the aggregate maturities for the next five years are as follows (in millions):

Calendar Year	Payment
2006	$ —
2007	2.4
2008	1.9
2009	175.3
2010	0.1
Thereafter	775.0
Total(1)	$ 954.7

(1) Excludes aggregate unamortized discount of $3.0 million on our various senior notes.

Note 5—Partners' Capital and Distributions

Units Outstanding

Partners' capital at December 31, 2005 consists of 73,768,576 common units outstanding, representing a 98% effective aggregate ownership interest in the Partnership and its subsidiaries, (after giving effect to the general partner interest), and a 2% general partner interest. The number of common units outstanding includes the 3,245,700 Class C common units and the 1,307,190 Class B common units that converted in February 2005.

Conversion of Class B and Class C Common Units

The Class B common units and Class C common units were *pari passu* with common units with respect to quarterly distributions. In accordance with a common unitholder vote at a special meeting on January 20, 2005, each Class B common unit and Class C common unit became convertible into one common unit upon request of the holder. In February 2005, all of the Class B and Class C common units converted into common units.

Conversion of Subordinated Units

Pursuant to the terms of our Partnership Agreement and having satisfied the financial tests contained therein, in November 2003, 25% of the subordinated units converted to common units on a one-for-one

basis. In February 2004, all of the remaining subordinated units converted to common units on a one-for-one basis.

The subordinated units had a debit balance in Partners' capital of approximately $39.9 million at December 31, 2003. The debit balance was the result of several different factors including: (i) a low initial capital balance in connection with the formation of the Partnership as a result of a low carry-over book basis in the assets contributed to the Partnership at the date of formation, (ii) a significant net loss in 1999 and (iii) distributions to unitholders that exceeded net income allocated to unitholders.

General Partner Incentive Distributions

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, generally the general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per unit, referred to as our minimum quarterly distributions ("MQD"), 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 (referred to as "incentive distributions"). Per unit cash distributions on our outstanding units and the portion of the distributions representing an excess over the MQD were as follows:

Year					
2005		2004		2003	
Distribution(1)	Excess over MQD	Distribution(1)	Excess over MQD	Distribution(1)	Excess over MQD

First Quarter	$ 0.6125	$ 0.1625	$ 0.5625	$ 0.1125	$ 0.5375	$ 0.0875
Second Quarter	$ 0.6375	$ 0.1875	$ 0.5625	$ 0.1125	$ 0.5500	$ 0.1000
Third Quarter	$ 0.6500	$ 0.2000	$ 0.5775	$ 0.1275	$ 0.5500	$ 0.1000
Fourth Quarter	$ 0.6750	$ 0.2250	$ 0.6000	$ 0.1500	$ 0.5500	$ 0.1000

(1) Distributions represent those declared and paid in the applicable period.

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. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established by our general partner for future requirements. Total cash distributions made were as follows (in millions, except per unit amounts):

	Distributions Paid					
	Common	Subordinated	GP			Distribution
Year	**Units**	**Units(1)**	**Incentive**	**2%**	**Total**	**per LP unit**
2005	$ 178.4	$ —	$ 15.0	$ 3.6	$ 197.0	$ 2.58
2004	$ 142.9	$ 4.2	$ 8.3	$ 3.0	$ 158.4	$ 2.30
2003	$ 92.7	$ 21.9	$ 4.9	$ 2.3	$ 121.8	$ 2.19

(1) The subordinated units converted to common units in 2003 and 2004.

On January 24, 2006, we declared a cash distribution of $0.6875 per unit on our outstanding common units. The distribution was paid on February 14, 2006 to unitholders of record on February 3, 2006, for the period October 1, 2005 through December 31, 2005. The total distribution paid was approximately $57.3 million, with approximately $50.7 million paid to our common unitholders and $1.0 million and $5.6 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Equity Offerings

During the three years ended December 31, 2005, we completed the following equity offerings of our common units. Certain of these offerings involve related parties. See Note 8 "Related Party Transactions."

Period	**Units**	**Gross Unit Price**	**Proceeds from Sale**	**GP Contribution**	**Costs**	**Net Proceeds**
		(in millions, except unit and per unit amounts)				
September/October 2005	5,854,000	$ 42.00	$ 246.0	$ 5.0	$ (9.1)	$ 241.9
February 2005	575,000	$ 38.13	$ 21.9	$ 0.5	$ (0.1)	$ 22.3
July/August 2004	4,968,000	$ 33.25	$ 165.2	$ 3.4	$ (7.7)	$ 160.9
April 2004	3,245,700	$ 30.81	$ 100.0	$ 2.0	$ (1.0)	$ 101.0
December 2003	2,840,800	$ 31.94	$ 90.7	$ 1.8	$ (4.1)	$ 88.4
September 2003	3,250,000	$ 30.91	$ 100.5	$ 2.1	$ (4.6)	$ 98.0
March 2003	2,645,000	$ 24.80	$ 65.6	$ 1.3	$ (3.0)	$ 63.9

Payment of Deferred Acquisition Price

In connection with the CANPET acquisition in July 2001, $26.5 million Canadian of the purchase price, payable in common units or cash at our option, was deferred subject to various performance objectives being met. These objectives were met as of December 31, 2003 and an increase to goodwill for this liability was recorded as of that date. The liability was satisfied on April 30, 2004 with the issuance of approximately 385,000 common units and the payment of $6.5 million in cash. The number of common units issued in satisfaction of the deferred payment was based upon $34.02 per share, the average trading price of our common units for the ten-day trading period prior to the payment date, and a Canadian dollar to U.S. dollar exchange rate of 1.35 to 1, the average noon-day exchange rate for the ten-day trading period prior to the payment date. In addition, an incremental $3.7 million in cash was paid for the distributions that would have been paid on the common units had they been outstanding since the effective date of the acquisition.

Note 6—Derivatives and Financial Instruments

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled trading program, (iii) manage our exposure to interest rate risk and (iv) manage our exposure to currency exchange rate risk. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX, International Petroleum Exchange ("IPE") and over-the-counter positions, as well as physical volumes, grades, locations and delivery schedules to ensure that our hedging activities address our market risks. We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. We calculate hedge effectiveness on a quarterly basis. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

Summary of Financial Impact

The majority of our derivative activity is related to our commodity price risk hedging activities. Through these activities, we hedge our exposure to price fluctuations with respect to crude oil and LPG in storage, as well as with respect to expected purchases, sales and transportation of these commodities. The derivative instruments we use consist primarily of futures and options contracts traded on the NYMEX, IPE and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies.

The majority of the instruments that qualify for hedge accounting are cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred to Accumulated Other Comprehensive Income ("OCI") and recognized in revenues or crude oil and LPG purchases and related costs in the periods during which the underlying physical transactions occur. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that is not highly effective, as defined in SFAS 133, in offsetting changes in cash flows of the hedged items are marked-to-market in revenues each period.

During 2005, our earnings include a net gain of approximately $18.4 million resulting from all derivative activities, including the change in fair value of open derivatives and settled derivatives taken to earnings during the period. This gain includes:

a) a net mark-to-market loss on open positions of $18.9 million, which is comprised of:

- the net change in fair value during the period of open derivatives used to hedge price exposure that do not qualify for hedge accounting (a loss of approximately $18.1 million) and
- the net change in fair value during the period of the portion of cash flow hedges related to open derivatives that is not highly effective in offsetting changes in cash flows of hedged items (a loss of approximately $0.8 million).

b) a net gain of $37.3 million related to settled derivatives taken to earnings during the period. The majority of this net gain is related to cash flow hedges that were recognized in earnings in conjunction with the underlying physical transactions that occurred during 2005.

During 2004, our earnings include a net gain of approximately $35.1 million resulting from all derivative activities, including the change in fair value of open derivatives and settled derivatives taken to earnings during the period. This gain includes:

a) a net mark-to-market gain on open positions of $1.0 million, which is comprised of:

- the net change in fair value during the period of open derivatives used to hedge price exposure that do not qualify for hedge accounting (a gain of approximately $0.9 million) and
- the net change in fair value during the period of the portion of cash flow hedges related to open derivatives that is not highly effective in offsetting changes in cash flows of hedged items (a gain of approximately $0.1 million).

b) a net gain of $34.1 million related to settled derivatives taken to earnings during the period. The majority of this net gain is related to our commodity price risk hedging activities that are offset by physical transactions, as discussed below.

The following table summarizes the net assets and liabilities related to the fair value of our open derivative positions on our consolidated balance sheet as of December 31, 2005 and 2004, respectively (in millions):

	December 31,	
	2005	2004
Other current assets	$ 45.7	$ 55.2
Other long-term assets	5.5	8.7
Other current liabilities	(72.5)	(18.9)
Other long-term liabilities and deferred credits	(6.5)	(10.6)
Net assets (liabilities)	$ (27.8)	$ 34.4

The net liability as of December 31, 2005 is comprised of $16.6 million of unrealized losses recognized in earnings and $11.2 million of unrealized losses on effective cash flow hedges that are deferred to OCI.

The majority of the $16.6 million of unrealized losses that have been recognized in earnings relate to activities associated with our storage assets. In general, revenue from storing crude oil is reduced in a backwardated market (when oil prices for future deliveries are lower than for current deliveries) as there is less incentive to store crude oil from month-to-month. We enter into derivative contracts that will offset the reduction in revenue by generating offsetting gains in a backwardated market structure. These derivatives do not qualify for hedge accounting because the contracts will not necessarily result in physical delivery. A portion of the net liability as of December 31, 2005, was caused by a reduction in backwardation (a decrease in the amount that the price of future deliveries are lower than current deliveries) from the time that we entered into the derivative contracts to the end of the year. The net gain or loss related to these instruments will offset storage revenue in the period that the derivative instruments are hedging.

At December 31, 2005 there was a total unrealized net loss of approximately $16.6 million deferred to OCI. This included $11.2 million (referenced above), which predominantly related to unrealized losses on derivatives used to hedge physical inventory in storage that receive hedge accounting, and $5.4 million relating to terminated interest rate swaps, which are being amortized to interest expense over the original terms of the terminated instruments. The inventory hedges are mostly short derivative positions that will result in losses when prices rise. These hedge losses are offset by an increase in the physical inventory value and will be reclassed into earnings from OCI in the same period that the underlying physical inventory is sold. The total amount of deferred net losses recorded in OCI are expected to be reclassified to future earnings, contemporaneously with the related physical purchase or delivery of the underlying commodity or payments of interest.

Of the total net loss deferred in OCI at December 31, 2005, a net loss of $12.9 million will be reclassified into earnings in the next twelve months and the remaining net loss at various intervals (ending in 2016 for amounts related to our terminated interest rate swaps and 2008 for amounts related to our commodity price-risk hedging). Because a portion of these amounts is based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

During the year ended December 31, 2005 and 2004, no amounts were reclassified to earnings from OCI in connection with forecasted transactions that were no longer considered probable of occurring.

The following sections discuss our risk management activities in the indicated categories.

Commodity Price Risk Hedging

We hedge our exposure to price fluctuations with respect to crude oil and LPG in storage, and expected purchases, sales and transportation of these commodities. The derivative instruments we use consist primarily of futures and option contracts traded on the NYMEX, IPE and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies. In accordance with SFAS 133, these derivative instruments are recognized in the balance sheet or earnings at their fair values. The majority of the instruments that qualify for hedge accounting are cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred into OCI and recognized in revenues or crude oil and LPG purchases and related costs in the periods during which the underlying physical transactions occur. We have determined that substantially all of our physical purchase and sale agreements qualify for the normal purchase and sale exclusion and thus are not subject to SFAS 133. Physical transactions that are derivatives and are ineligible, or become ineligible, for the normal purchase and sale treatment (e.g. due to changes in settlement provisions) are recorded in the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues.

Controlled Trading Program

Although we seek to maintain a position that is substantially balanced within our crude oil lease purchase 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. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. In accordance with SFAS 133, these derivative instruments are recorded in the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues.

Interest Rate Risk Hedging

At December 31, 2005, we had no open interest rate hedging instruments. However, there is approximately $5.4 million deferred in OCI that relates to cash flow hedge instruments that were terminated and cash settled ($0.8 million related to an instrument settled in 2005, $1.3 million related to an instrument settled in 2004 and $3.3 million related to instruments settled in 2003) that relate to debt agreements refinanced in 2005, 2004 and 2003, respectively. The deferred loss related to these instruments is being amortized into interest expense over the original terms of the terminated instruments (approximately $2.0 million over the next two years and the remaining $3.4 million over approximately ten years). Approximately $1.6 million and $1.5 million related to the terminated instruments were reclassified into interest expense during 2005 and 2004, respectively. In addition, earnings for 2004 include a loss of approximately $0.7 million that was reclassified out of OCI related to an instrument that matured in March 2004.

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in Canadian dollars and, at times, a portion of our debt is denominated in Canadian dollars, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include forward exchange contracts and cross currency swaps. Neither the forward exchange contracts nor the cross currency swaps qualify for hedge accounting in accordance with SFAS 133.

At December 31, 2005, we had forward exchange contracts that allow us to exchange $2.0 million Canadian dollars for $1.5 million U.S. dollars, quarterly during 2006 (based on a Canadian dollar to U.S. dollar exchange rate of 1.32 to 1).

In addition, at December 31, 2005, we also had cross currency swap contracts for an aggregate notional principal amount of $19.0 million, effectively converting this amount of our U.S. dollar denominated debt to $29.4 million of Canadian dollar debt (based on a Canadian dollar to U.S. dollar exchange rate of 1.55 to 1). The notional principal amount has a final maturity in May 2006 of $19.0 million U.S. At December 31, 2005, none of our long-term debt was denominated in Canadian dollars. All of these financial instruments are placed with what we believe to be large, creditworthy financial institutions.

Fair Value of Financial Instruments

The carrying amounts and fair values of our financial instruments are as follows (in millions):

	December 31,			
	2005		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
NYMEX futures	$ (16.0)	$ (16.0)	$ 42.3	$ 42.3
Options and swaps	$ (7.3)	$ (7.3)	$ (2.8)	$ (2.8)
Forward exchange contracts	$ (0.8)	$ (0.8)	$ (1.5)	$ (1.5)
Cross currency swaps	$ (6.4)	$ (6.4)	$ (6.3)	$ (6.3)
Short and long-term debt under credit facilities	$ 155.4	$ 155.4	$ 231.8	$ 231.8
Borrowings under senior secured hedged inventory facility	$ 219.3	$ 219.3	$ 80.4	$ 80.4
Senior notes	$ 947.0	$ 976.0	$ 797.3	$ 848.0

As of December 31, 2005 and 2004, the carrying amounts of items comprising current assets and current liabilities approximate fair value due to the short-term maturities of these instruments. The carrying amounts of the variable rate instruments in our credit facilities and senior secured hedged inventory facility approximate fair value primarily because the interest rates fluctuate with prevailing market rates, and the credit spread on outstanding borrowings reflects market. The interest rates on our senior notes are fixed and the fair value is based on quoted market prices.

The carrying amount of our derivative financial instruments approximate fair value as these instruments are recorded on the balance sheet at their fair value under SFAS 133. Our derivative financial instruments currently include cross currency swaps and forward exchange contracts for which fair values are based on current liquidation values. We also have over-the-counter option and swap contracts for which fair values are estimated based on various sources such as independent reporting services, industry publications and brokers. 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. In addition, we have NYMEX futures and options for which the fair values are based on quoted market prices.

Note 7—Major Customers and Concentration of Credit Risk

Marathon Petroleum Company LLC, and its predecessor Marathon Ashland Petroleum ("MAP"), accounted for 11%, 10% and 12% of our revenues for each of the three years in the period ended December 31, 2005. BP Oil Supply also accounted for 14% and 10% of our revenues for the years ended December 31, 2005 and 2004. No other customers accounted for 10% or more of our revenues during any of the three years. The majority of the revenues from MAP and BP Oil Supply pertain to our gathering, marketing, terminalling and storage 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.

Financial instruments that potentially subject us to concentrations of credit risk consist principally of trade receivables. Our accounts receivable are primarily from purchasers and shippers of crude oil. This industry concentration has the potential to impact our overall exposure to credit risk in that the customers may be similarly affected by changes in economic, industry or other conditions. We review credit exposure and financial information of our counterparties and generally require letters of credit for receivables from customers that are not considered creditworthy, unless the credit risk can otherwise be reduced.

Note 8—Related Party Transactions

Our General Partner

Reimbursement of Expenses of Our General Partner and Its Affiliates

We do not directly employ any persons to manage or operate our business. These functions are provided by employees of our general partner (or, in the case of our Canadian operations, PMC (Nova Scotia) Company). Our general partner does not receive a management fee or other compensation in connection with its management of us. We reimburse our general partner for all direct and indirect costs of services provided, including the costs of employee, officer and director compensation and benefits allocable to us, and all other expenses necessary or appropriate to the conduct of our business, and allocable to us. Our agreement provides that our general partner will determine the expenses allocable to us in any reasonable manner determined by our general partner in its sole discretion. Total costs reimbursed by us to our general partner for the years ended December 31, 2005, 2004 and 2003 were approximately $165.2 million, $151.0 million and $88.1 million, respectively.

Benefit Plan

Our general partner maintains a 401(k) defined contribution plan whereby it matches 100% of an employee's contribution (subject to certain limitations in the plan). For the years ended December 31, 2005, 2004 and 2003, the defined contribution plan matching expense was approximately $4.5 million, $4.0 million and $2.6 million, respectively. Similarly, PMC (Nova Scotia) Company maintains a group Registered Savings Plan and a Non Registered Employee Savings Plan for our Canadian employees. For the years ended December 31, 2005, 2004 and 2003, these plans had expense of approximately $1.4 million, $1.0 million and $0.7 million, respectively. All of these amounts are included above in the total costs reimbursed by us to our general partner.

Long-Term Incentive Plans

Our general partner maintains the 1998 LTIP and the 2005 LTIP for employees and directors of our general partner. The plans generally consist of two components, a restricted or phantom unit plan and a unit option plan, and cover delivery of an aggregate of 4,425,000 common units. The plans are administered by the compensation committee of our general partner's board of directors. See Note 9 "Long-Term Incentive Plans."

Performance Option Plan

In 2001, the owners of the general partner (other than PAA Management, L.P.) contributed an aggregate of 450,000 subordinated units (now converted into common units) to the general partner to provide a pool of units available for the grant of options to management and key employees. In that regard, the general partner adopted the Plains All American 2001 Performance Option Plan, pursuant to which options to purchase approximately 448,000 units have been granted. As of December 31, 2005, approximately 169,000 options remain outstanding under the plan, all of which are fully vested. The original exercise price of the options was $22 per unit, declining over time by an amount equal to 80% of each quarterly distribution per unit. As of December 31, 2005, the exercise price was approximately $13.85 per unit. The terms of future grants may differ from the existing grants. Because the units underlying the plan were contributed to the general partner, we have no obligation to reimburse the general partner for the cost of the units upon exercise of the options. In November and December of 2005, we sold approximately 170,000 units in a "10b5-1 Plan." The proceeds of the sales were allocated among the payment of tax liabilities and cash payments to optionees and to owners of the general partner.

Vulcan Energy Corporation

As of December 31, 2005, Vulcan Energy Corporation ("Vulcan Energy") and its affiliates owned approximately 54% of our general partner interest, as well as approximately 16.8% of our outstanding limited partner units.

Voting Agreement

In August 2005, one of the owners of our general partner notified the remaining owners of its intent to sell its 19% interest in the general partner. The remaining owners elected to exercise their right of first refusal, such that the 19% interest was purchased pro rata by all remaining owners. As a result of the transaction, the interest of Vulcan Energy increased from 44% to approximately 54%. At the closing of the transaction, Vulcan Energy entered into a voting agreement that restricts its ability to unilaterally elect or remove our independent directors, and separately, our CEO and COO agreed, subject to certain ongoing conditions, to waive certain change-of-control payment rights that would otherwise have been triggered by the increase in Vulcan Energy's ownership interest. These ownership changes to our general partner had no impact on us.

Administrative Services Agreement

On October 14, 2005, Plains All American GP LLC ("GP LLC") and Vulcan Energy entered into an Administrative Services Agreement, effective as of September 1, 2005 (the "Services Agreement"). Pursuant to the Services Agreement, GP LLC will provide administrative services to Vulcan Energy for consideration of approximately $650,000 per year, plus certain expenses. The Services Agreement will be effective for a period of three years, at which time it will automatically renew for successive one-year periods unless either party provides written notice of its intention to terminate the Services Agreement. Pursuant to the agreement, Vulcan Energy has appointed certain employees of GP LLC as officers of Vulcan Energy for administrative efficiency. Under the Services Agreement, Vulcan Energy acknowledges that conflicts may arise between itself and GP LLC. If GP LLC believes that a specific service is in conflict with the best interest of GP LLC or its affiliates then GP LLC is entitled to suspend the provision of that service and such a suspension will not constitute a breach of the Services Agreement. Vulcan Gas Storage LLC (discussed below) operates separately from Vulcan Energy, and we do not provide any services to Vulcan Gas Storage LLC under the Services Agreement.

Crude Oil Purchases from Calumet Florida L.L.C.

Until August 12, 2005, Vulcan Energy owned 100% of Calumet Florida L.L.C. ("Calumet"). Calumet is now owned by Vulcan Resources Florida, Inc., the majority of which is owned by Paul G. Allen. We purchase crude oil from Calumet and paid approximately $38.1 million, $28.3 million and $25.7 million to Calumet in 2005, 2004 and 2003, respectively. The majority of the $6.8 million balance due to related parties at December 31, 2005 is related to purchases of crude oil from Calumet in December 2005.

Equity Offering

On February 25, 2005, we issued 575,000 common units in a private placement to a subsidiary of Vulcan Energy. The sale price was $38.13 per unit, which represented a 2.8% discount to the closing price of the units on February 24, 2005. The sale resulted in net proceeds, including the general partner's proportionate capital contribution ($0.5 million) and net of expenses associated with the sale, of approximately $22.3 million.

Other Transactions

Investment in PAA/Vulcan Gas Storage, LLC

PAA/Vulcan, a limited liability company, was formed in 2005. PAA/Vulcan is owned 50% by us and the other 50% is owned by Vulcan Gas Storage LLC, a subsidiary of Vulcan Capital, the investment arm of Paul G. Allen. The Board of Directors of PAA/Vulcan is comprised of an equal number of our representatives and representatives of Vulcan Gas Storage and is responsible for providing strategic direction and policy-making. We are responsible for the day-to-day operations. PAA/Vulcan is not a variable interest entity, and we do not have the ability to control the entity; therefore, we account for the investment under the equity method in accordance with APB 18. This investment is reflected in other long-term assets in our consolidated balance sheet.

In September 2005, PAA/Vulcan acquired ECI, an indirect subsidiary of Sempra Energy, for approximately $250 million. ECI develops and operates underground natural gas storage facilities. We and Vulcan Gas Storage LLC each made an initial cash investment of approximately $112.5 million, and Bluewater Natural Gas Holdings, LLC, a subsidiary of PAA/Vulcan ("Bluewater") entered into a $90 million credit facility contemporaneously with closing. We currently have no direct or contingent obligations under the Bluewater credit facility.

We and Vulcan Gas Storage are both required to make capital contributions in equal proportions to fund (i) certain projects specified at the time PAA/Vulcan acquired ECI and (ii) unspecified future capital needs up to an aggregate of $20 million. For certain other specified projects, Vulcan Gas Storage has the right, but not the obligation, to participate for 50% of the cost. For any other project (or a project in which Vulcan Gas Storage declines to exercise its right to participate), we have the right to make additional capital contributions to fund 100% of the project. Such contributions would increase our interest in PAA/Vulcan and dilute Vulcan Gas Storage's interest. If at any time our interest in PAA/Vulcan exceeds 70%, Vulcan Gas Storage would have the right, but not the obligation, to make capital contributions proportionate to its ownership interest at the time.

In conjunction with formation of PAA/Vulcan and the acquisition of ECI, PAA and Paul G. Allen 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. PAA and Paul G. Allen would be required to perform under these guarantees only if ECI was unable to perform. In addition, we provided a guarantee under one contract with an indefinite life for which neither Vulcan Capital nor Paul G. Allen provided a guarantee. In exchange for the disproportionate guarantee, PAA will receive preference distributions totaling $1.0 million over ten years from PAA/Vulcan (distributions that would otherwise have been paid to Vulcan Gas Storage LLC). 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 extremely remote; however, there is no dollar limitation on potential future payments that fall under this obligation.

PAA/Vulcan will reimburse us for the allocated costs of PAA's non-officer staff associated with the management and day-to-day operations of PAA/Vulcan and all out-of-pocket costs. In addition, in the first fiscal year that EBITDA (as defined in the PAA/Vulcan LLC agreement) of PAA/Vulcan exceeds $75.0 million, we will receive a distribution from PAA/Vulcan equal to $6.0 million per year for each year since formation of the joint venture, subject to a maximum of 5 years or $30 million. Thereafter, we will receive annually a distribution equal to the greater of $2 million per year or two percent of the EBITDA of PAA/Vulcan.

Equity Offerings

Concurrently with our public offering of equity in September 2005, we sold 679,000 common units pursuant to our existing shelf registration statement to investment funds affiliated with Kayne Anderson Capital Advisors, L.P. ("KACALP") in a privately negotiated transaction for a purchase price of $40.512 per unit (equivalent to the public offering price less underwriting discounts and commissions). KAFU Holdings, L.P., which owns a portion of our general partner and has a representative on our board of directors, is managed by KACALP.

In April 2004, we sold 3,245,700 unregistered Class C common units to a group of investors comprised of affiliates of Kayne Anderson Capital Advisors, Vulcan Capital and Tortoise Capital pursuant to Rule 4(2) under the Securities Act. Affiliates of both Kayne Anderson Capital Advisors and Vulcan Capital own interests in our general partner. Total proceeds from the transaction, after deducting transaction costs and including the general partner's proportionate contribution, were approximately $101 million.

Note 9—Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the "1998 LTIP") and the 2005 Long-Term Incentive Plan (the "2005 LTIP") for employees and directors of our general partner and its affiliates who perform services for us. Our general partner's board of directors has the right to alter or amend the 2005 LTIP and the 1998 LTIP or any part of the plans from time to time, including, subject to any applicable NYSE listing requirements, increasing the number of common units with respect to which awards may be granted; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of such participant. Awards contemplated by the 2005 LTIP include phantom units, restricted units, unit appreciation rights and unit options, as determined by the compensation committee or the board of directors (each an "Award"). Up to 3 million units may be issued in satisfaction of Awards under the 2005 LTIP. Certain Awards may also include distribution equivalent rights ("DERs") in the discretion of the compensation committee or the board of directors. A DER entitles the grantee to a cash payment, either while the award is outstanding or upon vesting, equal to any cash distributions paid on a unit while the award is outstanding. Our general partner will be entitled to reimbursement by us for any costs incurred in settling obligations under the 2005 LTIP. Certain of these Awards could be considered a common stock equivalent and thus be dilutive to our earnings per unit from the time of their date of grant. Awards contemplated by the 1998 LTIP include phantom units and unit options. The 1998 LTIP currently permits the grant of phantom units and unit options covering an aggregate of 1,425,000 common units. No unit option grants have been made under the 1998 LTIP to date. However, the compensation committee or the board of directors may, in the future, make grants under the plan to employees and directors containing such terms as the compensation committee or the board of directors shall determine, provided that unit options have an exercise price equal to the fair market value of the units on the date of grant.

A phantom unit entitles the grantee to receive, upon the vesting of the phantom unit, a common unit (or cash equivalent, depending on the terms of the grant). The compensation committee or the board of directors may, in the future, make additional grants under the plans to employees and directors containing such terms as the compensation committee or the board of directors shall determine. Approximately 97,000 of the phantom units outstanding under the 1998 LTIP vested in 2005. We paid cash in lieu of delivery of common units for approximately 25,000 of the phantom units and issued approximately 47,000 new common units (after netting for taxes) in connection with the vesting. As of December 31, 2005, there are approximately 48,275 phantom units outstanding under the 1998 LTIP, which have vesting terms over the next four years, if certain performance criteria are met. The majority of the awards outstanding under the 1998 LTIP have performance-based vesting terms and, therefore, we recognize expense when it is considered probable that the performance criteria will be met.

Four of our non-employee directors each have received an LTIP award of 5,000 units. These awards vest annually in 25% increments (1,250 units each). The awards have an automatic re-grant feature such that as they vest, an equivalent amount is granted. For the other two non-employee directors, any director compensation is assigned to the entity that designated them as directors. In those cases, no LTIP award was granted, but in lieu, an equivalent cash payment is made. In June 2005, 5,000 non-employee director units vested.

Common units to be delivered upon the vesting of grants may be common units acquired by our general partner in the open market or in private transactions, common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units and any other costs incurred in settling obligations under the 2005 LTIP and 1998 LTIP. In addition, the Partnership may issue up to approximately 499,000 new common units under the 1998 LTIP and 3 million new common units under the 2005 LTIP to satisfy delivery obligations under the grants, less any common units issued upon exercise of unit options under the plan. If we issue new common units upon vesting of the phantom units, the total number of common units outstanding will increase. The compensation committee or the board of directors, in its discretion, may grant tandem DERs with respect to phantom units.

During 2005, our board of directors and compensation committee approved grants of approximately 2.2 million phantom units and 1.6 million DERs under the 2005 LTIP. Approximately 1.5 million of the phantom units vest over a six-year period (with performance accelerators), while the remaining awards vest over time only if certain performance criteria are met and are forfeited after seven years if the performance criteria are not met. No phantom units vest prior to the dates indicated below for each tranche. The DERs vest over time and terminate with the vesting or forfeiture of the related phantom units. The following awards were outstanding under the 2005 LTIP at December 31, 2005:

Summary of 2005 LTIP

As of December 31, 2005
(in thousands)

Annualized Distribution Rate	Date	Phantom Units A(1)	Phantom Units B(2)	Phantom Units Total	DERs A(1)	DERs B(2)	DERs Total
$2.60	May 2007	565	150	715	363	150	513
$2.70	May 2008	—	—	—	136	75	211
$2.80	May 2009	431	150	581	136	75	211
$2.90	May 2010	—	—	—	136	100	236
$3.00	May 2010	431	200	631	136	100	236
$2.90	May 2008	22	57	79	—	57	57
$3.00	May 2009	17	57	74	—	57	57
$3.10	May 2010	17	56	73	—	56	56
		1,483	670	2,153	907	670	1,577

(1) Awards that vest in May 2011 at the latest. Achievement of the indicated distribution rate performance criteria can accelerate the vesting to the date indicated. The phantom unit awards are common stock equivalents as they will vest at the end of a determinant time and thus are included in our diluted earnings per unit calculation.

(2) Awards that vest only upon the achievement of the distribution rate performance criteria and the date indicated. In addition, the awards will be forfeited if the performance criteria are not met in seven years. Until the performance criteria are met, these awards are not considered common stock equivalents in our diluted earnings per unit calculation.

The issuance of the common units upon vesting of phantom units is primarily intended to serve as a means of incentive compensation for performance. Therefore, no consideration is paid to us by the plan participants upon vesting and delivery of the common units. Compensation expense is recognized ratably over time for the phantom units and DERs that vest based on the passage of time. To the extent that the vesting of the awards or DERs is accelerated or considered probable of acceleration, the related compensation expense will also be accelerated. For those phantom units and DERs that vest only upon the achievement of performance criteria, expense is recognized when it is considered probable the criteria will be achieved.

We have concluded that it is probable that we will achieve a $3.00 annualized distribution rate and therefore have accelerated the recognition of compensation expense related to the portion of the awards that vest up to that rate. Under generally accepted accounting principles, we are required to recognize expense when it is considered probable that phantom unit grants under the LTIP plans will vest. As a result, we recognized total compensation expense of approximately $26.1 million in 2005 and $7.9 million in 2004 related to the awards granted under our 1998 LTIP and our 2005 LTIP plans.

Note 10—Commitments and Contingencies

Commitments

We lease certain real property, equipment and operating facilities under various operating and capital leases. We also incur costs associated with leased land, rights-of-way, permits and regulatory fees, the contracts for which generally extend beyond one year but can be cancelled at any time should they not be required for operations. Future non-cancellable commitments related to these items at December 31, 2005, are summarized below (in millions):

2006	$ 19.8
2007	$ 16.7
2008	$ 12.4
2009	$ 11.5
2010	$ 9.6
Thereafter	$ 44.0

Expenditures related to leases for 2005, 2004 and 2003 were $25.7 million, $20.1 million and $13.4 million, respectively.

Contingencies

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the "short supply" controls of the Export Administration Regulations ("EAR") and must be licensed by the Bureau of Industry and Security (the "BIS") of the U.S. Commerce Department. In 2002, we determined that we may have violated the terms of our licenses with respect to the quantity of crude oil exported and the end-users in Canada. Export of crude oil except as authorized by license is a violation of the EAR. In October 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and received several new licenses allowing for export volumes and end users that more accurately reflect our anticipated business and customer needs. We also conducted reviews of new and existing contracts and implemented new procedures and practices in order to monitor compliance with applicable laws regarding the export of crude oil to Canada. As a result, we subsequently submitted additional information to the BIS in October 2003 and May 2004. In August 2004, we received a request from the BIS for additional information. We have responded to this and subsequent requests, and continue to cooperate fully with BIS

officials. At this time, we have received neither a warning letter nor a charging letter, which could involve the imposition of penalties, and no indication of what penalties the BIS might assess. As a result, we cannot reasonably estimate the ultimate impact of this matter.

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 Pipeline, the U.S. Environmental Protection Agency ("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 $4.5 million to $5.0 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. We have been informed by EPA that it has referred these two crude oil releases, as well as several other smaller releases, to the U.S. Department of Justice for further investigation in connection with a possible civil penalty enforcement action under the Federal Clean Water Act.

General. We, in the ordinary course of business, are a claimant and /or a defendant in various legal proceedings. We do not believe that the outcome of these legal proceedings, individually and in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

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 prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business. As we expand our pipeline assets through acquisitions, we typically improve on (decrease) the rate of releases from such assets as we implement our standards and procedures, remove selected assets from service and spend capital to upgrade the assets. In the immediate post-acquisition period, however, the inclusion of additional miles of pipe in our operation may result in an increase in the absolute number of releases company-wide compared to prior periods. We have, in fact, experienced such an increase in connection with our 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. See "—Pipeline Releases" above.

At December 31, 2005, our reserve for environmental liabilities totaled approximately $22.4 million. At December 31, 2005, we have recorded receivables totaling approximately $14.2 million for amounts recoverable under insurance and from third parties under indemnification agreements. Although we believe our reserve is adequate, no assurance can be given that any costs incurred in excess of this reserve would not have a material adverse effect on our financial condition, results of operations or cash flows.

Hurricanes Katrina and Rita. During the third quarter of 2005 we experienced damage to various facilities and equipment resulting from hurricanes in the Gulf of Mexico. We have substantially completed

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preliminary assessments of damages and repair efforts are underway. We believe that the majority of the repair costs will be recovered through our insurance policies.

Other. A pipeline, terminal or other facility 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. 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 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 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, 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.

Note 11—Environmental Remediation

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

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

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

The acquisitions we completed in 2005, 2004 and 2003 include a variety of provisions dealing with the allocation of responsibility for environmental costs that range from no or limited indemnities from the

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sellers to indemnification from sellers with defined limitations on their maximum exposure. We have not obtained insurance for any of the conditions related to our 2005 and 2003 acquisitions, and only in limited circumstances for our 2004 acquisitions.

For instance, in connection with the Link acquisition, we identified a number of environmental liabilities for which we received a purchase price reduction from Link. A substantial portion of these environmental liabilities are associated with the former Texas New Mexico (“TNM”) pipeline assets. On the effective date of the acquisition, we and TNM entered into a cost-sharing agreement whereby, on a tiered basis, we agreed to bear $11 million of the first $20 million of pre-May 1999 environmental issues. We also agreed to bear the first $25,000 per site for new sites which were not identified at the time we entered into the agreement (capped at 100 sites). TNM agreed to pay all costs in excess of $20 million (excluding the deductible for new sites). TNM’s obligations are guaranteed by Shell Oil Products (“SOP”). We recorded a reserve for environmental liabilities of approximately $20.0 million in connection with the Link acquisition.

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

In connection with our 1999 acquisition of Scurlock Permian LLC from MAP, we were indemnified by MAP for any environmental liabilities attributable to Scurlock’s business or properties which 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.

Other assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified. We have in the past experienced and in the future will likely experience releases of crude oil into the environment from our pipeline and storage operations, or discover releases that were previously unidentified. Although we maintain a program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to environmental releases from our assets may substantially affect our business.

At December 31, 2005, our reserve for environmental liabilities totaled approximately $22.4 million (approximately $14.6 million of this reserve is related to liabilities assumed as part of the Link acquisition). Approximately $14.4 million of our environmental reserve is classified as current and $8 million is classified as long-term. At December 31, 2005, we have recorded receivables totaling approximately $14.2 million ($7.7 million related to estimated future remediation costs) for amounts recoverable under insurance and from third parties under indemnification agreements.

In some cases, the actual cash expenditures may not occur for three to five years. We believe that this reserve is adequate, and in conjunction with our indemnification arrangements, should prevent remediation costs from having a material adverse effect on our financial condition, results of operations, or cash flows. 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, no assurances can be made that any costs incurred in excess of this reserve or outside of the indemnifications would not have a material adverse effect on our financial condition, results of operations, or cash flows.

Note 12—Quarterly Financial Data (Unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total[1]
	(in millions, except per unit data)				
2005					
Revenues[2]	$ 6,638.5	$ 7,160.7	$ 8,664.4	$ 8,713.7	$ 31,177.3
Gross margin	69.4	102.2	111.4	95.8	378.8
Operating income	47.3	76.0	84.9	67.4	275.6
Net income	32.8	62.3	69.0	53.7	217.8
Basic net income per limited partner unit	0.43	0.76	0.81	0.65	2.77
Diluted net income per limited partner unit	0.43	0.74	0.79	0.64	2.72
Cash distributions per common unit[3]	$ 0.613	$ 0.638	$ 0.650	$ 0.675	$ 2.58
2004					
Revenues[2]	$ 3,804.6	$ 5,131.7	$ 5,867.0	$ 6,172.1	$ 20,975.5
Gross margin	59.6	64.9	74.5	63.7	262.7
Operating income	40.5	45.2	55.1	39.2	180.0
Income before cumulative effect of change in accounting principle	31.0	35.7	41.7	24.7	133.1
Net income	27.9	35.7	41.7	24.7	130.0
Basic and diluted income per limited partner unit before cumulative effect of change in accounting principle	0.49	0.54	0.59	0.32	1.94
Basic and diluted income per limited partner unit	0.44	0.54	0.59	0.32	1.89
Cash distributions per common unit[3]	$ 0.563	$ 0.563	$ 0.578	$ 0.600	$ 2.30

(1) The sum of the four quarters does not equal the total year due to rounding.

(2) Includes buy/sell transactions. See Note 2.

(3) Represents cash distributions declared and paid in the applicable period.

Note 13—Operating Segments

Our operations consist of two operating segments: (i) pipeline transportation operations and (ii) gathering, marketing, terminalling and storage operations. Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and we operate certain terminalling and storage assets. We believe that our terminalling and storage activities and gathering and marketing activities are counter-cyclical. We believe that this balance of activities, combined with our pipeline transportation operations, generally provides us with the flexibility to maintain a base level of margin irrespective of whether a strong or weak market exists and, in certain circumstances, to realize incremental margin during volatile market conditions. In a contango market (oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (oil prices for future deliveries are lower than for current deliveries), we use and lease less storage capacity, but increased marketing margins (premiums for prompt delivery resulting from high demand) provide an offset to this reduced cash flow. In addition, we supplement the counter-cyclical balance of our asset base with derivative hedging activities.

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues less (i) purchases and related costs, (ii) field operating costs, and (iii) segment general and administrative 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. Therefore, 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. Management compensates for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance costs, which mitigate the actual decline in the value of our principal fixed assets. These maintenance costs 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 or expand the operating capacity are charged to expense as incurred. The following table reflects certain financial data for each segment for the periods indicated:

	Pipeline	GMT&S (in millions)	Total
Twelve Months Ended December 31, 2005[1]			
Revenues:			
External Customers (includes buy/sell revenues of $197.1, $16,077.8, and $16,274.9, respectively)[2]	$ 991.6	$ 30,185.7	$ 31,177.3
Intersegment[3]	138.7	0.9	139.6
Total revenues of reportable segments	$ 1,130.3	$ 30,186.6	$ 31,316.9
Segment profit[2][4][5]	$ 175.2	$ 183.9	$ 359.1
Capital expenditures	$ 127.0	$ 67.1	$ 194.1
Total assets[6]	$ 1,480.4	$ 2,526.4	$ 4,006.8
SFAS 133 impact[2]	$ —	$ (18.9)	$ (18.9)
Maintenance capital	$ 8.4	$ 5.6	$ 14.0
Twelve Months Ended December 31, 2004			
Revenues:			
External Customers (includes buy/sell revenues of $149.8, $11,247.0, and $11,396.8, respectively)[2]	$ 752.9	$ 20,222.6	$ 20,975.5
Intersegment[3]	122.0	0.9	122.9
Total revenues of reportable segments	$ 874.9	$ 20,223.5	$ 21,098.4
Segment profit[2][4][5]	$ 157.2	$ 91.5	$ 248.7
Capital expenditures	$ 520.7	$ 131.5	$ 652.2
Total assets	$ 1,507.5	$ 1,652.9	$ 3,160.4
SFAS 133 impact[2]	$ —	$ 1.0	$ 1.0
Maintenance capital	$ 8.3	$ 3.0	$ 11.3

Twelve Months Ended December 31, 2003			
Revenues:			
External Customers (includes buy/sell revenues of $166.2, $6,124.9, and $6,291.1, respectively)[2]	$ 605.1	$ 11,984.7	$ 12,589.8
Intersegment[3]	53.5	0.9	54.4
Total revenues of reportable segments	$ 658.6	$ 11,985.6	$ 12,644.2
Segment profit[2][4][5]	$ 81.3	$ 63.1	$ 144.4
Capital expenditures	$ 211.9	$ 21.9	$ 233.8
Total assets	$ 1,221.0	$ 874.6	$ 2,095.6
SFAS 133 impact[2]	$ —	$ 0.4	$ 0.4
Maintenance capital	$ 6.4	$ 1.2	$ 7.6

(1) During 2005, we reclassified certain minor pipeline gathering assets from the GMT&S segment to the Pipeline segment. Historically, we have been the sole shipper on these assets as part of our gathering and marketing operations. Prior period segment information has not been restated for this change since the impact to such periods was not material.

(2) Amounts related to SFAS 133 are included in GMT&S revenues and impact segment profit.

(3) Intersegment sales are conducted at arms length.

(4) GMT&S segment profit includes interest expense on contango inventory purchases of $23.7 million, $2.0 million and $1.0 million for the twelve months ended December 31, 2005, 2004 and 2003, respectively.

(5) The following table reconciles segment profit to consolidated income before cumulative effect of change in accounting principle (in millions):

	Year ended December 31, 2005	2004	2003
Segment profit	$ 359.1	$ 248.7	$ 144.4
Depreciation and amortization	(83.5)	(68.7)	(46.2)
Equity earnings in PAA/Vulcan Gas Storage, LLC	1.0	—	—
Interest expense	(59.4)	(46.7)	(35.2)
Interest income and other (expense), net	0.6	(0.2)	(3.6)
Income before cumulative effect of change in accounting principle	$ 217.8	$ 133.1	$ 59.4

(6) Total assets, as reported on the consolidated balance sheet, includes the $113.5 million investment in PAA/Vulcan Gas Storage, LLC, which is not included in either of our operating segments.

Geographic Data

We have operations in the United States and Canada. Set forth below are revenues and long lived assets attributable to these geographic areas (in millions):

	For the Year Ended December 31,		
	2005	2004	2003
Revenues			
United States (includes buy/sell revenues of $14,749.0, $10,164.6, and $5,621.6, respectively)	$ 26,199.7	$ 17,499.5	$ 10,536.8
Canada (includes buy/sell revenues of $1,525.9, $1,232.2, and $669.5, respectively)	4,977.6	3,476.0	2,053.0
	$ 31,177.3	$ 20,975.5	$ 12,589.8

	December 31,	
	2005	2004
Long-Lived Assets		
United States	$ 1,887.0	$ 1,670.8
Canada	422.5	379.7
	$ 2,309.5	$ 2,050.5

Exhibit 10.21

Quarterly Bonus Program Summary

Certain officers and employees in our marketing group and business development group participate in a quarterly bonus arrangement based on EBITDA from our commercial activities during the quarter. Total participants include approximately 80 employees.

Exhibit 10.22

Director Compensation Summary

Each director of our general partner who is not an employee of our general partner is reimbursed for any travel, lodging and other out-of-pocket expenses related to meeting attendance or otherwise related to service on the board (including, without limitation, reimbursement for continuing education expenses). Non-employee directors receive no perquisites or other personal benefits. Each non-employee director is currently paid an annual retainer fee of $45,000. Mr. Armstrong is otherwise compensated for his services as an employee and therefore receives no separate compensation for his services as a director. In addition to the annual retainer, each committee chairman (other than the chairman of the audit committee) receives $2,000 annually. The chairman of the audit committee receives $30,000 annually, and the other members of the audit committee receive $15,000 annually, in each case, in addition to the annual retainer. Mr. Petersen assigns any compensation he receives in his capacity as a director to EnCap Energy Capital Fund III, L.P. (EnCap III), which is controlled by EnCap Investments L.P., of which Mr. Petersen is a Managing Director. Mr. Capobianco assigns any compensation he receives in his capacity as a director to Vulcan Capital.

Except as described below, each non-employee director has received an LTIP award of 5,000 units in the aggregate. These units vest annually in 25% increments, subject to an automatic re-grant of the amount vested, such that the director will always have outstanding an award of 5,000 units. For Mr. Petersen and Mr. Capobianco, a cash equivalent payment will be made to EnCap III and Vulcan Capital, respectively, upon any vesting. The units will vest in full upon the next vesting date after the death or disability (as determined in good faith by the board) of the director. For any “independent” directors (as defined in the GP LLC Agreement, and currently including Messrs. Goyanes, Smith and Symonds), the units will also vest in full if such director (i) retires (no longer with full-time employment and no longer serving as an officer or director of any public company) or (ii) is removed from the Board or is not reelected to the Board, unless such removal or failure to reelect is for “good cause,” as defined in the letter granting the phantom units.

Exhibit 10.24

«GrantDate»

«FirstName» «MI» «LastName»
«Address1»
«City», «State» «PostalCode»

Re: Grant of Restricted Units
(Effective February 17, 2005)

Dear «FirstName»:

I am pleased to inform you that you have been granted «Units» Phantom Units as of the above date pursuant to the Company's 2005 Long-Term Incentive Plan (the "Plan"). In addition, in tandem with each Phantom Unit you have been granted a distribution equivalent right (a "DER"). The terms and conditions of this grant are as set forth below.

1. Subject to the further provisions of this Agreement, your Phantom Units shall vest (become payable in the form of one Common Unit of Plains All American Pipeline, L.P. for each Phantom Unit) as follows: (i) 30% shall vest upon the later to occur of the May 2007 Distribution Date and the date on which the Partnership pays a quarterly dividend of $0.65 per unit, (ii) 30% shall vest upon the later to occur of the May 2009 Distribution Date and the date on which the Partnership pays a quarterly distribution of $0.70 per unit, and (iii) 40% shall vest upon the later to occur of the May 2010 Distribution Date and the date on which the Partnership pays a quarterly distribution of $0.75 per unit. Any Phantom Units that remain unvested, and all associated DERs (whether or not vested), as of the May 2012 Distribution Date (after giving effect to the distribution on such date) shall be forfeited.

2. Subject to the further provisions of this Agreement, your DERs shall vest (become payable in cash) as follows: (i) 30% shall vest upon and effective with the earlier to occur of the May 2007 Distribution Date and the date on which the Partnership pays a quarterly dividend of $0.65 per unit, (ii) 15% shall vest upon and effective with the earlier to occur of the May 2008 Distribution Date and the date on which the Partnership pays a quarterly distribution of $0.675 per unit, (iii) 15% shall vest upon and effective with the earlier to occur of the May 2009 Distribution Date and the date on which the Partnership pays a quarterly distribution of $0.70 per unit, (iv) 20% shall vest upon and effective with the earlier to occur of the May 2010 Distribution Date and the date on which the Partnership pays a quarterly distribution of $.725 per unit, and (v) 20% shall vest upon and effective with the earlier to occur of the May 2010 Distribution Date and the date on which the Partnership pays a quarterly distribution of $0.75 per unit.

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3. Your DERs shall not accrue payments prior to vesting.

4. Any distribution level required for vesting under paragraphs 1 or 2 above shall be proportionately reduced or increased for any split or reverse split, respectively, of the Units, or any event or transaction having similar effect.

5. Upon vesting of any Phantom Units, an equivalent number of DERs will expire. Any such DERs that are vested prior to, or that would vest as of, the Distribution Date on which the Phantom Units vest, shall be payable on such Distribution Date prior to their expiration.

6. In the event of the termination of your employment with the Company and its Affiliates (other than in connection with a Change in Status or by reason of your death or "disability," as defined in paragraph 7 below), all of your then outstanding DERs (regardless of vesting) and Phantom Units shall automatically be forfeited as of the date of termination; provided, however, that if the Company or its Affiliates terminate your employment other than a Termination for Cause, any unvested Phantom Units that have satisfied all vesting criteria as of the date of termination but for the passage of time shall be deemed nonforfeitable on the date of termination, and shall vest on the next following Distribution Date; provided, further, that any DERs associated with the unvested, nonforfeitable Phantom Units described in the preceding proviso shall not be forfeited on the date of termination, but shall be payable and shall expire in accordance with paragraph 5 above.

7. In the event of termination of your employment with the Company and its Affiliates by reason of your death or your "disability" (a physical or mental infirmity that impairs your ability substantially to perform your duties for a period of eighteen months or that the Company otherwise determines constitutes a "disability"), all of your then outstanding Phantom Units and tandem DERs shall be deemed 100% nonforfeitable on such date, and such Phantom Units shall vest in accordance with paragraph 1 and paragraph 2 above.

8. In the event of a Change in Status, all of your then outstanding Phantom Units and tandem DERs shall be deemed 100% nonforfeitable on such date, and such Phantom Units shall vest in full upon the next Distribution Date.

9. Upon payment pursuant to a DER, you agree that the Company may withhold any taxes due from your compensation as required by law. Upon vesting of a Phantom Unit, you agree that the Company may withhold any taxes due from your compensation as required by law, which (in the sole discretion of the Company) may include withholding a number of Common Units otherwise payable to you.

As used herein, the phrase "Distribution Date" means the date, in any given month and year, on which the Partnership pays a quarterly distribution.

The phrase "Change in Status" means the occurrence, within three months prior to or one year following a Change of Control, of any of the following circumstances: (A) any termination by the Company of your employment other than a Termination for Cause, (B) without your consent, any removal of you from, or any failure to re-elect you to, the positions held by you (or substantially equivalent positions) immediately prior to the change that may constitute a Change in Status, or (C) any reduction in your base salary or (D) any material reduction in your fringe benefits.

The phrase “Change of Control” means, and shall be deemed to have occurred upon the occurrence of, one or more of the following events: (i) the Company ceasing to be the general partner of the general partner of the Partnership, (ii) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all of the assets of the Partnership or the Company to any Person and/or its Affiliates, other than to the Partnership or the Company, including any employee benefit plan thereof; (iii) a consolidation, reorganization, merger or any other similar transaction involving (a) a Person other than the Partnership or the Company and (b) the Partnership, the Company or both, (iv) the Persons who own membership interests in the Company on the date hereof cease to beneficially own, directly or indirectly, more than 50% of the membership interest in the Company, or (v) any Person, including any partnership, limited partnership, syndicate or other group deemed a “person” for purposes of Section 13(d) or 14(d) of the Securities Exchange Act of 1934, as amended, becoming the beneficial owner, directly or indirectly, of more than 49.9% of the membership interest in the Company (a “Majority Holder”); provided, however, that if any Person [including any partnership, limited partnership, syndicate or other group deemed a “person” for purposes of Section 13(d) or 14(d) of the Securities Exchange Act of 1934, as amended,] who is a member of the Company as of March 1, 2005, or any Affiliate of any such Person, becomes a Majority Holder, a Change of Control shall not be deemed to have occurred pursuant to this clause (v) if at or prior to the time such Person becomes a Majority Holder, such Person executes and delivers to the Company an agreement substantially in the form of Exhibit A hereto (the “Specified Voting Agreement”); provided, further, however, that if, following the execution and delivery to the Company of the Specified Voting Agreement by such Majority Holder, (x) such Majority Holder shall give written notice to the Company of termination of such Specified Voting Agreement pursuant to Section 3 thereof (and such written notice is not withdrawn prior to the effectiveness of such termination), then a Change of Control shall be deemed to have occurred upon the effectiveness of such termination if, at the time of the effectiveness of such termination, such Majority Holder beneficially owns, directly or indirectly, more than 49.9% of the membership interests in the Company or (y) such Majority Holder shall breach or anticipatorily breach the Specified Voting Agreement, then a Change of Control shall be deemed to have occurred at the time of such breach (or anticipatory breach) of the Specified Voting Agreement if, at the time of such breach, such Majority Holder beneficially owns, directly or indirectly, more than 49.9% of the membership interests in the Company.

The phrase “Termination for Cause” shall mean severance of your employment with the Company or its Affiliates based on your (i) failure to perform your job function in accordance with standards described to you in writing, or (ii) violation of the Company’s Code of Business Conduct (unless waived in accordance with the terms thereof), in each case, with the specific failure or violation described to you in writing.

The “Company” refers to Plains All American GP LLC. The “Partnership” refers to Plains All American Pipeline, L.P.

Terms used herein that are not defined herein shall have the meanings set forth in the Plan or, if not defined in the Plan, in the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., as amended (the “Partnership Agreement”). By signing below, you agree that the Phantom Units and DERs granted hereunder are governed by the terms of the Plan. Copies of the Plan and the Partnership Agreement are available upon request. Please execute and return this Agreement to me. The attached copy of this Agreement is for your records.

PLAINS ALL AMERICAN PIPELINE, L.P.

By: PLAINS AAP, L.P.

By: PLAINS ALL AMERICAN GP LLC

By: ______________________________
Name:
Title:

____
«FirstName» «MI» «LastName»

SSN: «SSN»

Units: «Units»

Dated: ______________________________

Exhibit 10.39

November 17, 2005

«FirstName» «MI» «LastName»
«Address»
«City», «State» «Zip»

Re: Grant of Restricted Units

Dear «FirstName»:

I am pleased to inform you that you have been granted «Units» Phantom Units as of the above date pursuant to the Company’s 2005 Long-Term Incentive Plan (the “Plan”). In addition, in tandem with each Phantom Unit you have been granted a distribution equivalent right (a “DER”). The terms and conditions of this grant are as set forth below.

1. Subject to the further provisions of this Agreement, your Phantom Units shall vest (become payable in the form of one Common Unit of Plains All American Pipeline, L.P. for each Phantom Unit) as follows: (i) 33.3% shall vest upon the later to occur of the May 2008 Distribution Date and the date on which the Partnership pays a quarterly dividend of $0.725 per unit, (ii) 33.3% shall vest upon the later to occur of the May 2009 Distribution Date and the date on which the Partnership pays a quarterly distribution of $0.75 per unit, and (iii) 33.3% shall vest upon the later to occur of the May 2010 Distribution Date and the date on which the Partnership pays a quarterly distribution of $0.775 per unit. Any remaining Phantom Units that are not vested by the May 2012 Distribution Date shall expire.

2. Subject to the further provisions of this Agreement, your DERs shall vest (become payable in cash) as follows: (i) 33.3% shall vest upon and effective with the date on which the Partnership pays a quarterly dividend of $0.725 per unit, (ii) 33.3% shall vest upon and effective with date on which the Partnership pays a quarterly distribution of $0.75 per unit, (iii) 33.3% shall vest upon and effective with the date on which the Partnership pays a quarterly distribution of $0.775 per unit. Any remaining DERs that are not vested by the May 2012 Distribution Date shall expire.

3. Your DERs shall not accrue payments prior to vesting.

4. Any distribution level required for vesting under paragraphs 1 or 2 above shall be proportionately reduced or increased for any split or reverse split, respectively, of the Units, or any event or transaction having similar effect.

5. Upon vesting of any Phantom Units, an equivalent number of DERs will expire. Any such DERs that are vested prior to, or that would vest as of, the Distribution Date on which the Phantom Units vest, shall be payable on such Distribution Date prior to their expiration.

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6. In the event of the termination of your employment with the Company and its Affiliates (other than in connection with a Change in Status or by reason of your death or “disability,” as defined in paragraph 7 below), all of your then outstanding DERs (regardless of vesting) and Phantom Units shall automatically be forfeited as of the date of termination; provided, however, that if the Company or its Affiliates terminate your employment other than a Termination for Cause, any unvested Phantom Units that have satisfied all vesting criteria as of the date of termination but for the passage of time shall be deemed nonforfeitable on the date of termination, and shall vest on the next following Distribution Date; provided, further, that any DERs associated with the unvested, nonforfeitable Phantom Units described in the preceding proviso shall not be forfeited on the date of termination, but shall be payable and shall expire in accordance with paragraph 5 above.

7. In the event of termination of your employment with the Company and its Affiliates by reason of your death or your “disability” (a physical or mental infirmity that impairs your ability substantially to perform your duties for a period of eighteen months or that the Company otherwise determines constitutes a “disability”), all of your then outstanding Phantom Units and tandem DERs shall be deemed 100% nonforfeitable on such date, and such Phantom Units shall vest in accordance with paragraph 1 (other than the last sentence thereof) and paragraph 2 above.

8. In the event of a Change in Status, all of your then outstanding Phantom Units and tandem DERs shall be deemed 100% nonforfeitable on such date, and such Phantom Units shall vest in full upon the next Distribution Date.

9. Upon payment pursuant to a DER, you agree that the Company may withhold any taxes due from your compensation as required by law. Upon vesting of a Phantom Unit, you agree that the Company may withhold any taxes due from your compensation as required by law, which (in the sole discretion of the Company) may include withholding a number of Common Units otherwise payable to you.

As used herein, the phrase “Distribution Date” means the date, in any given month and year, on which the Partnership pays a quarterly distribution.

The phrase “Change in Status” means the occurrence, within three months prior to or one year following a Change of Control, of any of the following circumstances: (A) any termination by the Company of your employment other than a Termination for Cause, (B) without your consent, any removal of you from, or any failure to re-elect you to, the positions held by you (or substantially equivalent positions) immediately prior to the change that may constitute a Change in Status, or (C) any reduction in your base salary or (D) any material reduction in your fringe benefits.

The phrase “Change of Control” means, and shall be deemed to have occurred upon the occurrence of, one or more of the following events: (i) the Company ceasing to be the general partner of the general partner of the Partnership, (ii) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all of the assets of the Partnership or the Company to any Person and/or its Affiliates, other than to the Partnership or the Company, including any employee benefit plan thereof; (iii) a consolidation, reorganization, merger or any other similar transaction involving (a) a Person other than the Partnership or the Company and

(b) the Partnership, the Company or both, (iv) the Persons who own membership interests in the Company on the date hereof cease to beneficially own, directly or indirectly, more than 50% of the membership interest in the Company, or (v) any Person, including any partnership, limited partnership, syndicate or other group deemed a "person" for purposes of Section 13(d) or 14(d) of the Securities Exchange Act of 1934, as amended, becoming after the date hereof the beneficial owner, directly or indirectly, of more than 49.9% of the membership interest in the Company.

The phrase "Termination for Cause" shall mean severance of your employment with the Company or its Affiliates based on your (i) failure to perform your job function in accordance with standards described to you in writing, or (ii) violation of the Company's Code of Business Conduct (unless waived in accordance with the terms thereof), in each case, with the specific failure or violation described to you in writing.

The "Company" refers to Plains All American GP LLC. The "Partnership" refers to Plains All American Pipeline, L.P.

Terms used herein that are not defined herein shall have the meanings set forth in the Plan or, if not defined in the Plan, in the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., as amended (the "Partnership Agreement"). By signing below, you agree that the Phantom Units and DERs granted hereunder are governed by the terms of the Plan. Copies of the Plan and the Partnership Agreement are available upon request. Please execute and return this Agreement to me. The attached copy of this Agreement is for your records

PLAINS ALL AMERICAN PIPELINE, L.P.

By: PLAINS AAP, L.P.

By: PLAINS ALL AMERICAN GP LLC

By: ______________________________
Name:
Title:

____
«FirstName» «MI» «LastName»

Units: «Units»

SSN: «SSN»

Dated: ______________________________

Exhibit 10.40

Plains All American GP LLC

December 18, 2001

Mr. John P. von Berg
14131 Hays
Houston, TX 77069

Dear John:

Pursuant to our discussions, the following shall set forth the employment agreement between Plains All American GP LLC (the "Company") and John P. von Berg ("Employee"):

1. The position will be Director, Trading. Employee's activities will be part of a Business Unit with one or more other employees of the Company.

2. Compensation will include:

a. a monthly salary of $16,667.00 which will be payable semi-monthly, with salary review from time to time consistent with Company's compensation practices,

b. your allocated share of a fiscal quarterly bonus pool (QBP). The QBP will be equal to 4% of your Business Unit's Gross Margin (as hereinafter defined). In the event that there is a loss in any quarter, such amount shall be recouped before earnings in a subsequent quarter are eligible for participation in the QBP. Employee and the Senior Vice President will determine the allocation of percentages of the QBP among the employees in the Business Unit.

For purposes of this agreement, Gross Margin shall mean the earnings (directly generated by your Business Unit only) before FASB 133 adjustments, income taxes, depreciation and amortization less:

(i) all overhead attributable to the Business Unit,
(ii) interest costs (net of interest income) and other direct costs incurred through borrowings for inventory or fees for letters of credits associated with Business Unit transactions, and
(iii) brokerage commissions, consultant or professional services fees or other similar charges.

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c. participation in the discretionary annual bonus pool. The amount, if any, of the annual bonus pool and the amount therefrom allocable to Employee shall be in the sole discretion of the Senior Vice President and President.

3. Employee shall receive:

a. 12,500 Restricted Units of Plains All American Pipeline, L.P. under the Company's 1998 Long-Term Incentive Plan, to vest 90 days after conversion of subordinated units into common units and subject to further vesting criteria as follows:

Vesting Distribution Level #1	25.0%	(Individual Target $2MM First year Business Unit Gross Margin)	
Vesting Distribution Level #2	25.0%	$	2.10
Vesting Distribution Level #3	25.0%	$	2.30
Vesting Distribution Level #4	25.0%	$	2.50
	100.0%		

b. 12,500 Performance Options to purchase existing Subordinated Units in accordance with, and subject to the vesting criteria described in, the Consent of Sole Member of the Company dated as of June 7, 2001 with vesting criteria as follows:

Vesting Distribution Level #1	25.0%	$	2.10
Vesting Distribution Level #2	25.0%	$	2.30
Vesting Distribution Level #3	25.0%	$	2.50
Vesting Distribution Level #4	25.0%	$	2.70
	100.0%		

The initial strike price will be $22.00 per unit. This strike price will be reduced by an amount equal to 80% of the actual distributions made on such units. The life of the option will be 10 years and vesting of the options will be tied to unit performance as measured by the annualized distribution level set forth in the table above.

c. The opportunity, but not the obligation to purchase, within 60 days from Employee's first day of employment, but in no event later than March 1, 2002 an interest in PAA Management LLC ("LLC") and a limited partner interest in PAA Management, L.P. ("LP"), for a purchase price of $150,000.00; provided that Employee agrees to and does execute the documents required to consummate this investment. If the interests are acquired from existing owners, the interests will be a 5% membership interest in LLC and a 4.95% interest in LP. If new interests are issued, the interests in the LLC and LP will be proportionately reduced.

4. Monthly expense reimbursements will include reasonable and legitimate business travel and entertainment expenses including membership at one country club or athletic club.

5. Other benefits will include: (i) four weeks paid vacation, (ii) up to 10 days sick leave with pay, (iii) participation in the Company's 401(K) Plan and (iv) participation in the Company's insurance benefit program which is currently comprised of the benefits set forth on Exhibit A.

6. (a) If the Company causes this agreement to terminate for any reason except gross negligence or willful misconduct of Employee, Employee's monthly base salary will be continued for a period that is the greater of (a) if more than twelve months remain in the unexpired portion of the initial term, the remainder of the initial term of this agreement as provided in paragraph 8 or (b) if less than twelve months remain in the unexpired portion of the initial term or any successive term of this agreement, twelve months. Employee will be reimbursed for up to six months of COBRA insurance. Upon payment of such amounts, the Company shall not have any further salary obligation to Employee.

(b) In the event Employee causes this agreement to terminate for reasons other than as set forth in paragraph 6(c), the Company shall not have any further obligation to Employee under paragraphs 2 and 3 of this agreement or for severance (and the obligations under paragraph under paragraph 6(a) will not apply).

(c) Unless otherwise agreed by the Company and Employee, in the event there is a material change in circumstances of the employment of Employee whereby either (1) the Company's home office is relocated to a new location, or the Employee's place of employment is relocated, outside of a 50 mile radius from 333 Clay Street, Houston, Texas, or (2) the Company institutes a reduction in Employee's base salary, or (3) there is a material reduction in Employee's responsibilities, or (4) the Company eliminates the oil trading function or merchant activities of the Company; then in each such case the obligations of the Company under paragraph 6(a) shall apply.

7. Contemporaneous with the execution of this agreement, Employee and the Company shall execute a Confidential Information and Non-Solicitation Agreement (the "Confidentiality Agreement") substantially in the form of Exhibit "B" attached hereto. The rights and obligations set forth in the Confidentiality Agreement shall survive the termination of this agreement, even if this agreement is terminated pursuant to the terms of paragraph 6 above, or paragraph 8, below.

8. Unless terminated earlier pursuant to the provisions of paragraph 6 above, this agreement shall

(i) have an initial term of twenty four months beginning January 31, 2002 (or as soon as Employee can commence his employment at the discretion of Employee) and

(ii) Shall thereafter automatically be extended and continue for up to three successive terms of one year each, provided that during the twelve month period immediately prior to each such successive term, Employee's Business Unit shall have generated Gross Margin of not less than $2,000,000.00 with Employee's active full time services.

The Company may terminate this agreement prior to the end of the initial term or any successive term in the event of gross negligence or willful misconduct by the Employee, in which case Paragraph 6(a) shall not apply.

9. Upon termination of this agreement for any reason, Employee shall promptly return to Company all copies of any Company data, records, or materials of whatever nature or kind, including all materials incorporating the proprietary information of Company. Employee shall also furnish to Company all work in progress or portions thereof, including all incomplete work.

10. Employee represents that (i) execution of this agreement will not violate the terms of any agreement to which Employee is currently bound, and (ii) Employee is not subject to an existing confidentiality, non-compete or similar type agreement that would prevent, limit or otherwise encumber Employee's ability to purchase crude oil on behalf of the Company.

11. By accepting this offer, Employee agrees that he shall at all times:

(i) adhere to the Company's Trading and Risk Management Policies and Procedures,
(ii) adhere to the standard of integrity, ethics, conflicts of interest, compliance with statutory law and regulations and other applicable standards of personal conduct while employed by the Company, and
(iii) not misrepresent nor conceal information regarding transactions from senior management or any person responsible for the accurate recording and reporting of each transaction.

If the foregoing meets with your understanding of our agreement, please execute, date and return one original agreement for our files.

Very truly yours,

PLAINS ALL AMERICAN GP LLC

/s/ George R. Coiner
George R. Coiner
Senior Vice President

Agreed to and accepted
this 15th day of January 2002.

/s/ John von Berg
John von Berg

Exhibit 10.41

THIRD AMENDMENT TO RESTATED CREDIT AGREEMENT

THIS THIRD AMENDMENT TO RESTATED CREDIT AGREEMENT (this "Amendment") dated as of the 4th day of November 2005, by and among PLAINS MARKETING, L.P. ("Borrower"), BANK OF AMERICA, N.A., as Administrative Agent, BNP Paribas, as Syndication Agent, Fortis Capital Corp., as Documentation Agent, and the Lenders party hereto.

W I T N E S S E T H:

WHEREAS, Borrower, Administrative Agent and Lenders named therein entered into that certain Restated Credit Agreement dated as of November 19, 2004, as amended by First Amendment to Restated Credit Agreement dated as of April 20, 2005 and Second Amendment to Restated Credit Agreement dated as of May 20, 2005 (as heretofore amended, the "Original Agreement") for the purposes and consideration therein expressed; and

WHEREAS, Borrower, Administrative Agent and Lenders desire to amend the Original Agreement for the purposes described herein;

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements contained herein and in the Original Agreement, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto do hereby agree as follows:

ARTICLE I. — Definitions and References

§ 1.1. Terms Defined in the Original Agreement. Unless the context otherwise requires or unless otherwise expressly defined herein, the terms defined in the Original Agreement shall have the same meanings whenever used in this Amendment.

§ 1.2. Other Defined Terms. Unless the context otherwise requires, the following terms when used in this Amendment shall have the meanings assigned to them in this § 1.2.

"Amendment" means this Third Amendment to Credit Agreement.

"Credit Agreement" means the Original Agreement as amended hereby.

ARTICLE II. — Amendments

§ 2.1. Definitions. The definition of "Request Period Termination Date" set forth in Section 1.1 of the Original Agreement is hereby amended in its entirety, effective as of November 19, 2005, to read as follows

"Request Period Termination Date" means November 19, 2006, as such date may be extended pursuant to Section 2.9.

§ 2.2. Schedules The Pricing Grid attached as Schedule I to the Original Agreement is hereby amended in its entirety, effective as of the effectiveness hereof, to read as set forth on Schedule I attached hereto. The Lender Schedule attached as Schedule II to the Original Agreement shall remain unchanged and shall continue to read as set forth on Schedule II attached hereto.

§ 2.3. Confirmation of Prior Approved Financing Request Each Lender a party hereto hereby confirms that it has previously approved the following Financing Request, which specifies a funding date after the current Request Termination Date of November 19, 2005, and acknowledges and agrees that such approval shall apply notwithstanding that the extension of the Request Period Termination Date as provided in Section 2.1 hereof is not yet effective:

1. Financing Request-Initial dated October 10, 2005 with respect to a Delivery Month of October, 2005 and an Initial Financing Request of $292,400,000.

ARTICLE III. — Conditions of Effectiveness

§ 3.1. Effective Date. This Amendment shall become effective as of the date first written above, when and only when

(i) Administrative Agent shall have received, at Administrative Agent's office a counterpart of this Amendment executed and delivered by Borrower and Lenders;

(ii) Administrative Agent shall have additionally received all of the following documents, each document (unless otherwise indicated) being dated the date of receipt thereof by Administrative Agent, duly authorized, executed and delivered, and in form and substance satisfactory to Administrative Agent:

Supporting Documents. Such supporting documents as Administrative Agent may reasonably request.

ARTICLE IV. — Representations and Warranties

§ 4.1. Representations and Warranties of Borrower. In order to induce Administrative Agent and Lenders to enter into this Amendment, Borrower represents and warrants to Administrative Agent and each Lender that:

(a) The representations and warranties contained in Article V of the Original Agreement are true and correct at and as of the time of the effectiveness hereof, except to the extent that such representation and warranty was made as of a specific date or updated, modified or supplemented as of a subsequent date with the consent of Majority Lenders, then in each case, such other date.

(b) Borrower is duly authorized to execute and deliver this Amendment, and Borrower is and will continue to be duly authorized to borrow and perform its obligations under the Credit Agreement. Borrower has duly taken all action necessary to authorize the execution and delivery of this Amendment and to authorize the performance of its obligations hereunder.

(c) The execution and delivery by Borrower of this Amendment, the performance by it of its obligations hereunder, and the consummation of the transactions contemplated hereby, do not and will not (i) violate any provision of (1) Law applicable

to it, (2) its organizational documents, or (3) any judgment, order or material license or permit applicable to or binding upon it, (ii) result in the acceleration of any Indebtedness owed by it, or (iii) result in or require the creation of any consensual Lien upon any of its material assets or properties, except as expressly contemplated in, or permitted by, the Loan Documents. Except as expressly contemplated in, or permitted by, the Loan Documents, disclosed in the Disclosure Schedule or disclosed pursuant to Section 6.4 of the Credit Agreement, no permit, consent, approval, authorization or order of, and no notice to or filing, registration or qualification with, any Governmental Authority is required on the part of Borrower pursuant to the provisions of any material Law applicable to it as a condition to its execution, delivery or performance of this Amendment, or to consummate the transactions contemplated hereby.

(d) When duly executed and delivered, this Amendment and each of the Loan Documents, as amended hereby, will be a legal and binding obligation of Borrower, enforceable in accordance with its terms, except as such enforcement may be limited by bankruptcy, insolvency or similar Laws of general application relating to the enforcement of creditors' rights and general principles of equity.

ARTICLE V. — Miscellaneous

§ 5.1. Ratification of Agreements. The Original Agreement, as hereby amended, is hereby ratified and confirmed in all respects. The Loan Documents, as they may be amended or affected by this Amendment, are hereby ratified and confirmed in all respects by Borrower. Any reference to the Credit Agreement in any Loan Document shall be deemed to refer to this Amendment also. The execution, delivery and effectiveness of this Amendment shall not, except as expressly provided herein, operate as a waiver of any right, power or remedy of Administrative Agent or any Lender under the Credit Agreement or any other Loan Document nor constitute a waiver of any provision of the Credit Agreement or any other Loan Document.

§ 5.2. Ratification of Security Documents. Borrower, Administrative Agent, and Lenders each acknowledge and agree that any and all indebtedness, liabilities or obligations, arising under or in connection with the LC Obligations or the Notes, are Obligations and are secured indebtedness under, and are secured by, each and every Security Document. Borrower hereby re-pledges, re-grants and re-assigns a security interest in and lien on every asset of Borrower described as Collateral in any Security Document.

§ 5.3. Survival of Agreements. All representations, warranties, covenants and agreements of Borrower shall survive the execution and delivery of this Amendment and the performance hereof, including without limitation the making or granting of each Loan, and shall further survive until all of the Obligations under the Credit Agreement are paid in full. All statements and agreements contained in any certificate or instrument delivered by Borrower hereunder or under the Credit Agreement to Administrative Agent or any Lender shall be deemed to constitute representations and warranties by, or agreements and covenants of, Borrower under this Amendment and under the Credit Agreement.

§ 5.4. Loan Documents. This Amendment is a Loan Document, and all provisions in the Credit Agreement pertaining to Loan Documents apply hereto.

§ 5.5. GOVERNING LAW. THIS AMENDMENT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK AND ANY APPLICABLE LAWS OF THE UNITED STATES OF AMERICA IN ALL RESPECTS, INCLUDING CONSTRUCTION, VALIDITY AND PERFORMANCE.

§ 5.6. Counterparts. This Amendment may be separately executed in counterparts and by the different parties hereto in separate counterparts, each of which when so executed shall be deemed to constitute one and the same Amendment. Delivery of an executed signature page by facsimile transmission shall be effective as delivery of a manual executed counterpart.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

IN WITNESS WHEREOF, this Amendment is executed as of the date first above written.

BORROWER: PLAINS MARKETING, L.P.

By: Plains Marketing GP Inc., General Partner

By: ______________________________
Al Swanson,
Vice President — Finance and Treasurer

LENDER PARTIES:

BANK OF AMERICA, N.A.,
Administrative Agent, LC Issuer and Lender

By: ______________________________
Name:
Title:

BNP PARIBAS, Syndication Agent and a Lender

By: ______________________________
Name:
Title:

By: ______________________________
Name:
Title:

FORTIS CAPITAL CORP.,
Documentation Agent and a Lender

By: ______________________________
Name:
Title:

By: ______________________________
Name:
Title:

SOCIETE GENERALE, Lender

By: ______________________________
Name:
Title:

By: ______________________________
Name:
Title:

WACHOVIA BANK, NATIONAL ASSOCIATION, Lender

By: ______________________________
Name:
Title:

BANK OF SCOTLAND, Lender

By: ______________________________
Name:
Title:

COMERICA BANK, Lender

By: ______________________________
Name:
Title:

WELLS FARGO BANK, N.A., Lender

By: ______________________________
Name:
Title:

JPMORGAN CHASE BANK, N.A., Lender

By: ____________________
Name:
Title:

COMMERZBANK AG, NEW YORK AND GRAND CAYMAN BRANCHES, Lender

By: ____________________
Name:
Title:

By: ____________________
Name:
Title:

THE BANK OF NOVA SCOTIA, Lender

By: ____________________
Name:
Title:

SUNTRUST BANK, Lender

By: ____________________
Name:
Title:

Exhibit 21.1

SUBSIDIARIES OF
PLAINS ALL AMERICAN PIPELINE, L.P.
(*As of December 31, 2005*)

Subsidiary	Jurisdiction of Organization
PAA Finance Corp.	Delaware
Plains Marketing, L.P.	Texas
Plains Pipeline, L.P.	Texas
Plains Marketing GP Inc.	Delaware
Plains Marketing Canada LLC	Delaware
Plains Marketing Canada, L.P.	Canada
PMC (Nova Scotia) Company	Nova Scotia
Basin Holdings GP LLC	Delaware
Basin Pipeline Holdings, L.P.	Delaware
Rancho Holdings GP LLC	Delaware
Rancho Pipeline Holdings, L.P.	Delaware
Plains LPG Services GP LLC	Delaware
Plains LPG Services, L.P.	Delaware
Atchafalaya Pipeline, L.L.C.	Delaware
Plains LPG Marketing, L.P.	Texas
Plains Marketing International GP LLC	Delaware
Plains Marketing International, L.P.	Texas

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-126447) and on Form S-8 (Nos. 333-91141, 333-54118, 333-74920 and 333-122806) of Plains All American Pipeline, L.P. of our report dated March 2, 2006 relating to the consolidated financial statements, management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

Houston, Texas
March 2, 2006

EXHIBIT 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PLAINS ALL AMERICAN PIPELINE, L.P.

I, Greg L. Armstrong, certify that:

1. I have reviewed this annual report on Form 10-K of Plains All American Pipeline, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2006
/s/ Greg L. Armstrong
Greg L. Armstrong
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PLAINS ALL AMERICAN PIPELINE, L.P.

I, Phil Kramer, certify that:

1. I have reviewed this annual report on Form 10-K of Plains All American Pipeline, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2006
/s/ Phil Kramer
Phil Kramer
Chief Financial Officer

EXHIBIT 32.1

**CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. 1350**

I, Greg L. Armstrong, Chief Executive Officer of Plains All American Pipeline, L.P. (the “Company”), hereby certify that:

(i) the accompanying report on Form 10-K for the period ended December 31, 2005 and filed with the Securities and Exchange Commission on the date hereof (the “Report”) by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Greg L. Armstrong
Name: Greg L. Armstrong
Date: March 2, 2006

EXHIBIT 32.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. 1350

I, Phil Kramer, Chief Financial Officer of Plains All American Pipeline, L.P. (the "Company"), hereby certify that:

(i) the accompanying report on Form 10-K for the period ended December 31, 2005 and filed with the Securities and Exchange Commission on the date hereof (the "Report") by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Phil Kramer
Name: Phil Kramer
Date: March 2, 2006