PLAINS ALL AMERICAN PIPELINE LP
Form 10-K
February 28, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2011

or

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

Commission file number 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**76-0582150** (I.R.S. Employer Identification No.)
333 Clay Street, Suite 1600, Houston, Texas (Address of principal executive offices)	**77002** (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 o

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

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

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

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

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

The aggregate market value of the Common Units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Common Units outstanding, for this purpose, as if they may be affiliates of the registrant) was approximately $8.4 billion on June 30, 2011, based on a closing price of $64.00 per Common Unit as reported on the New York Stock Exchange on such date.

As of February 22, 2012, there were 155,568,749 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

NONE

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

FORM 10-K 2011 ANNUAL REPORT

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FORWARD-LOOKING STATEMENTS

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

- failure to consummate and integrate the BP NGL Acquisition;

- failure to implement or capitalize on planned internal growth projects;

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

- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;

- the effectiveness of our risk management activities;

- unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);

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

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

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

- the availability of adequate third-party production volumes for transportation and marketing in the areas in which we operate and other factors that could cause declines in volumes shipped on our pipelines by us and third-party shippers, such as declines in production from existing oil and gas reserves or failure to develop additional oil and gas reserves;

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

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

- our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;

- the 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, governmental regulations, accounting standards and statements, and related interpretations;

- the effects of competition;

- interruptions in service on third-party pipelines;

- increased costs or lack of availability of insurance;

- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;

- the currency exchange rate of the Canadian dollar;

- weather interference with business operations or project construction;
- risks related to the development and operation of natural gas storage facilities;
- factors affecting demand for natural gas and natural gas storage services and rates;
- general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns; and
- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the storage of natural gas and the processing, transportation, fractionation, storage and marketing of natural gas liquids.

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

PART I

Items 1 and 2. *Business and Properties*

General

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

We engage in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the processing, transportation, fractionation, storage and marketing of natural gas liquids (NGL). The term NGL includes ethane and natural gasoline products as well as propane and butane, products which are also commonly referred to as liquefied petroleum gas (LPG). As used in this Form 10-K, the terms NGL and LPG are sometimes used interchangeably depending on the context. Through our general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P. (NYSE: PNG), we also own and operate natural gas storage facilities. Our business activities are conducted through three operating segments: Transportation, Facilities and Supply and Logistics.

Organizational History

We were formed as a master limited partnership to acquire and operate the midstream crude oil businesses and assets of a predecessor entity and completed our initial public offering in 1998. Our 2% general partner interest is held by PAA GP LLC, a Delaware limited liability company, whose sole member is Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P. s general partner. References to our general partner, as the context requires, include any or all of PAA GP LLC, Plains AAP, L.P. and Plains All American GP LLC. Plains AAP, L.P. and Plains All American GP LLC are owned by 18 holders and their affiliates. The five largest of these holders and their affiliates own an aggregate interest of approximately 95%. See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters Beneficial Ownership of General Partner Interest.

Partnership Structure and Management

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

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The chart below depicts the current structure and ownership of Plains All American Pipeline, L.P. and certain subsidiaries as of February 22, 2012.

(1) Based on Form 4 filings for executive officers and directors, 13D filings for Richard Kayne and other information believed to be reliable for the remaining investors, this group, or affiliates of such investors, owns approximately 9.5 million limited partner units, representing approximately 6% of all outstanding units.

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

(3) The Partnership holds direct and indirect ownership interests in consolidated operating subsidiaries including, but not limited to, Plains Pipeline, L.P., Plains Marketing, L.P., Plains LPG Services, L.P., Pacific Energy Group LLC and Plains Midstream Canada ULC (PMC).

(4) The Partnership holds direct and indirect equity interests in unconsolidated entities including Settoon Towing, LLC (Settoon Towing), White Cliffs Pipeline, LLC (White Cliffs), Butte Pipe Line Company (Butte) and Frontier Pipeline Company (Frontier).

Business Strategy

Our principal business strategy is to provide competitive and efficient midstream transportation, terminalling, storage, processing, fractionation and supply and logistics services to our producer, refiner and other customers. Toward this end, we endeavor to address regional supply and demand imbalances for crude oil, refined products, NGL and natural gas in the United States and Canada by combining the strategic location and capabilities of our transportation, terminalling, storage, processing and fractionation assets with our extensive supply, logistics and distribution expertise.

We believe successful execution of this strategy will enable us to generate sustainable earnings and cash flow. We intend to manage and grow our business by:

- optimizing our existing assets and realizing cost efficiencies through operational improvements;

- using our transportation, terminalling, storage, processing and fractionation assets in conjunction with our supply and logistics activities to capitalize on inefficient energy markets and to address physical market imbalances, mitigate inherent risks and increase margin;

- developing and implementing internal growth projects that (i) address evolving crude oil, refined products, natural gas and NGL needs in the midstream transportation and infrastructure sector and (ii) are well positioned to benefit from long-term industry trends and opportunities;

- selectively pursuing strategic and accretive acquisitions that complement our existing asset base and distribution capabilities; and

- capitalizing on the anticipated long-term growth in demand for natural gas storage services in North America by owning and operating high-quality natural gas storage facilities and providing our current and future customers reliable, competitive and flexible natural gas storage and related services through our ownership interest in PNG.

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. In that regard, we intend to maintain a credit profile that we believe is consistent with our 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 45% to 50%;

- a long-term debt-to-adjusted EBITDA multiple averaging between 3.5x and 4.0x (Adjusted EBITDA is earnings before interest, taxes, depreciation and amortization, equity compensation plan charges, gains and losses from derivative activities and other selected items that impact comparability. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Non-GAAP Financial Measures for a discussion of our selected items that impact comparability and our non-GAAP measures.);

- an average total debt-to-total capitalization ratio of approximately 60%; and

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

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The first two of these four metrics include long-term debt as a critical measure. In certain market conditions, we also incur short-term debt in connection with our supply and logistics activities that involve the simultaneous purchase and forward sale of crude oil, NGL and natural gas. The crude oil, NGL and natural gas purchased in these transactions are hedged. We do not consider the working capital borrowings associated with these activities to be part of our long-term capital structure. These borrowings are self-liquidating as they are repaid with sales proceeds. We also incur short-term debt to fund New York Mercantile Exchange (NYMEX) and IntercontinentalExchange (ICE) margin requirements.

In order for us to maintain our targeted credit profile and achieve growth through internal growth projects and acquisitions, we intend to fund 55% of the capital requirements associated with these activities with equity and cash flow in excess of distributions. From time to time, we may be outside the parameters of our targeted credit profile as, in certain cases, these capital expenditures and acquisitions may be financed initially using debt or there may be delays in realizing anticipated synergies from acquisitions or contributions from capital expansion projects to adjusted EBITDA.

Competitive Strengths

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

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

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

- *Our supply and logistics activities typically generate a base level of margin with the opportunity to realize incremental margins.* We believe the variety of activities executed within our supply and logistics segment in combination with our risk management strategies provides us with a balance that generally affords us the flexibility to maintain a base level of margin in a variety of market conditions (subject to the effects of seasonality). In certain circumstances, we are able to realize incremental margins 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 fourteen years, we have completed and integrated over 70 acquisitions with an aggregate purchase price of approximately $8.2 billion. We have also implemented internal expansion capital projects totaling approximately $3.0 billion. In addition, we believe we have resources to finance future strategic expansion and acquisition opportunities. As of December 31, 2011, we had over $3.6 billion available under our committed credit facilities, subject to continued covenant compliance.

- *We have an experienced management team whose interests are aligned with those of our unitholders.* Our executive management team has an average of 27 years industry experience, and an average of 16 years with us or our predecessors and affiliates. In addition, through their ownership of common units, indirect interests in our general partner, grants of phantom units and the Class B units in Plains AAP, L.P., our management team has a vested interest in our continued success.

Acquisitions

The acquisition of assets and businesses that are strategic and complementary to our existing operations constitutes an integral component of our business strategy and growth objective. Such assets and businesses include crude oil related assets, refined products assets, NGL assets and natural gas storage assets, as well as other energy transportation related assets that have characteristics and opportunities similar to these business lines and enable us to leverage our asset base, knowledge base and skill sets.

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The following table summarizes acquisitions greater than $200 million that we have completed over the past five years (in millions). See Note 3 to our Consolidated Financial Statements for a full discussion regarding our acquisition activities.

Acquisition	Date	Description		Approximate Purchase Price(1)
Western Refining, Inc. (Western)	Dec-2011	Multi-product storage facility in Virginia and Crude oil pipeline in southeastern New Mexico	$	220(2)
Velocity South Texas Gathering, LLC (Velocity)	Nov-2011	Crude oil and condensate gathering and transportation assets in South Texas (Gardendale Gathering System)	$	349
SG Resources Mississippi, LLC (SG Resources)	Feb-2011	Southern Pines Energy Center (Southern Pines) natural gas storage facility	$	765(3)
Nexen Holdings U.S.A. Inc. (Nexen)	Dec-2010	Crude oil gathering business and transportation assets in North Dakota and Montana	$	229(4)
PAA Natural Gas Storage, LLC (PNGS)	Sep-2009	Remaining 50% interest in PNGS	$	215(5)
Rainbow Pipe Line Company, Ltd. (Rainbow)	May-2008	Crude oil gathering and transportation assets in Alberta, Canada	$	687(6)

(1) As applicable, the approximate purchase price includes total cash paid and debt assumed, including amounts for working capital and inventory.

(2) Includes two transactions with Western.

(3) Acquisition made by our subsidiary, PNG. Approximate purchase price of $750 million, net of cash and other working capital acquired.

(4) Approximate purchase price of $170 million, net of cash, inventory and other working capital acquired.

(5) In connection with the PNGS acquisition we consolidated and subsequently refinanced approximately $450 million of previously non-recourse joint venture debt.

(6) Approximate purchase price of $544 million, net of linefill acquired.

Ongoing Acquisition Activities

Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase of assets and operations that are strategic and complementary to our existing operations. In addition, we have in the past evaluated and pursued, and intend in the future to evaluate and pursue, other energy-related assets that have characteristics and opportunities similar to our existing 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.

We typically do not announce a transaction until after we have executed a definitive acquisition agreement. However, in certain cases in order to protect our business interests or for other reasons, we may defer public announcement of an acquisition until closing or a later date. Past experience has demonstrated that discussions and negotiations regarding a potential acquisition can advance or terminate in a short period of time. Moreover, the closing of any transaction for which we have entered into a definitive acquisition agreement will be subject to customary and other closing conditions, which may not ultimately be satisfied or waived. Accordingly, we can give no assurance that our current or future acquisition efforts will be successful. Although we expect the acquisitions we make to be accretive in the long term, we can provide no assurance that our expectations will ultimately be realized. See Item 1A. Risk Factors Risks Related to Our Business If we do not make acquisitions or if we make acquisitions that fail to perform as anticipated, our future growth may be limited and Our acquisition strategy involves risks that may adversely affect our business.

Pending BP NGL Acquisition. On December 1, 2011, we entered into a definitive agreement to acquire all outstanding shares of BP Canada Energy Company, a wholly owned subsidiary of BP Corporation North America Inc. (BP North America). Total consideration for the acquisition, which will be based on an October 1, 2011 effective date, is approximately $1.67 billion, subject to working capital and other adjustments. A cash deposit of $50 million was paid upon signing, and the balance, plus 2% interest from October 1, 2011, is payable in cash upon closing. Subject to Canadian and U.S. regulatory approvals and other customary closing conditions, the acquisition is expected to close in the second quarter of 2012.

Upon completion of this acquisition, we will become the indirect owner of all of BP North America s Canadian-based NGL business and certain of BP North America s NGL assets located in the upper-Midwest United States (collectively the BP NGL Assets). The BP NGL Assets to be acquired include varying ownership interests and contractual rights relating to approximately 2,600 miles of NGL pipelines; approximately 20 million barrels of NGL storage capacity; seven fractionation plants with an aggregate net capacity of approximately 232,000 barrels per day; four straddle plants and two field gas processing plants with an aggregate net capacity of approximately six Bcf per day; and long-term and seasonal NGL inventories of approximately 10 million barrels as of October 1, 2011. Certain of these pipelines and storage assets are currently inactive. The acquired business also includes various third-party supply contracts at other field gas processing plants and a supply contract relating to a third-party owned straddle plant with throughput capacity of 2.5 Bcf per day, shipping arrangements on third-party NGL pipelines and long-term leases on 720 rail cars used to move product among various locations. Collectively, these assets and activities provide access to approximately 140,000 to 150,000 barrels per day of NGL supply that are transported through an integrated network to fractionation facilities and markets in Western and Eastern

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Canada and in the U.S. Subject to closing the transaction, we have also entered into an Integrated Supply and Trading Agreement, pursuant to which an affiliate of BP North America will, for a period of two years following the closing of the acquisition, continue to provide sourcing services for gas supply to feed certain of the straddle plants to be acquired as a result of the acquisition.

Global Petroleum Market Overview

The United States comprises less than 4% of the world s population, generates approximately 12% of the world s petroleum production, and consumes approximately 22% of the world s petroleum production. The following table sets forth projected world supply and demand for petroleum products (including crude oil and NGL) and is derived from the Energy Information Administration s (EIA) Annual Energy Outlook 2012 Early Release (see EIA website at *www.eia.doe.gov*):

			Projected		
	2011 (1)	**2012**	**2013**	**2015**	**2020**
		(In millions of barrels per day)			
Supply					
OECD (2)					
U.S.	10.3	10.4	10.5	11.0	12.0
Other	11.8	12.0	12.0	11.6	11.2
Total OECD	22.1	22.4	22.5	22.6	23.2
Organization of the Petroleum Exporting Countries	34.4	34.9	35.8	36.4	38.5
Other	31.6	32.2	31.8	32.9	35.1
Total World Production	88.1	89.5	90.1	91.9	96.8

			Projected		
	2011 (1)	**2012**	**2013**	**2015**	**2020**
		(In millions of barrels per day)			
Demand					
OECD					
U.S.	19.3	19.1	18.9	19.3	19.4
Other	26.6	26.8	27.0	26.8	27.6
Total OECD	45.9	45.9	45.9	46.1	47.0
Other	42.2	43.6	44.2	45.8	49.8
Total World Consumption	88.1	89.5	90.1	91.9	96.8
U.S. Production as % of World Production	12%	12%	12%	12%	12%
U.S. Consumption as % of World Consumption	22%	21%	21%	21%	20%
Net U.S. (Consumption)	(9.0)	(8.7)	(8.4)	(8.3)	(7.4)

(1) The 2011 amounts are based on ten months of actual data and two months of data derived from a short-term energy model published by the EIA.

(2) Organization for Economic Co-operation and Development.

World economic growth is a driver of the world petroleum market. The challenging global economic climate of the last several years has resulted in continued uncertainty in the petroleum market. To the extent that an event causes weaker world economic growth, energy demand would likely decline and could result in lower energy prices, depending on the production responses of producers.

Crude Oil Market Overview

The definition of a commodity is a mass-produced unspecialized product and implies the attribute of fungibility. Crude oil is typically referred to as a commodity; however, it is neither unspecialized nor fungible. The crude slate available to U.S. and world-wide refineries consists of a substantial number of different grades and varieties of crude oil. Each crude grade has distinguishing physical properties. For example, specific gravity (generally referred to as light or heavy), sulfur content (generally referred to as sweet or sour) and metals content, along with other characteristics, collectively result in varying economic attributes. In many cases, these factors result in the need for such grades to be batched or segregated in the transportation and storage processes, blended to precise specifications or adjusted in value.

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The lack of fungibility of the various grades of crude oil creates logistical transportation, terminalling and storage challenges and inefficiencies associated with regional volumetric supply and demand imbalances. These logistical inefficiencies are created as certain qualities of crude oil are indigenous to particular regions or countries. Also, each refinery has a distinct configuration of process units designed to handle particular grades of crude oil. The relative yields and the cost to obtain, transport and process the crude oil drives the refinery s choice of feedstock. In addition, from time to time, natural disasters and geopolitical factors such as hurricanes, earthquakes, tsunamis, inclement weather, labor strikes, refinery disruptions, embargoes and armed conflicts may impact supply, demand and transportation and storage logistics.

Our assets and our business strategy are designed to serve our producer and refiner customers by addressing regional crude oil supply and demand imbalances that exist in the United States and Canada. The nature and extent of these imbalances change from time to time as a result of a variety of factors, including regional production declines and/or increases; refinery expansions, modifications and shut-downs; available transportation and storage capacity and government mandates and related regulatory factors.

For the 20-year time period beginning in 1985 through 2004, U.S. refinery demand for crude oil increased approximately 29% from approximately 12.0 million barrels per day to approximately 15.5 million barrels per day. U.S. refinery demand for crude oil remained effectively flat from 2005 through 2007 at around 15.5 million barrels per day. Largely as a result of a major economic slowdown and recession, from 2008 to 2011 total U.S. petroleum consumption declined and refinery demand decreased, averaging approximately 14.8 million barrels per day for the 12 months ended October 2011. Of this amount, approximately 5.7 million barrels per day were produced domestically. Accordingly, for the 12 months ended October 2011, approximately 9.1 million barrels per day of the crude oil used by U.S. refineries were imported. This level of crude oil imports represents a meaningful change in a multi-year trend where foreign imports of crude oil tripled over a 23-year period, from approximately 3.2 million barrels per day in 1985 to approximately 10.1 million barrels per day from 2005-2007. Reduced domestic demand for petroleum products from end users and competitive challenges faced by certain U.S. refineries with limited access to domestic feedstocks as well as increased use of ethanol for blending in gasoline have been major factors contributing to the drop in refinery demand for crude oil, partially offset by rising refined products exports. Since 2000, ethanol production has grown from approximately 100,000 barrels per day to approximately 900,000 barrels per day for the 12 months ended October 2011. Growth in ethanol and other renewable fuel production is expected to continue primarily due to government mandates on production. The EIA is currently forecasting a continued gradual decline in foreign crude imports from current levels, which is attributable to increased domestic production and increased supply from other liquid products, including ethanol and biodiesel.

The table below shows the overall domestic petroleum consumption projected out to 2020 and is derived from recent information published by the EIA (see EIA website at *www.eia.doe.gov*). The amounts in the 2011 column are based on the twelve months from November 2010 to October 2011**.** We believe these trends will be subject to significant variation from time to time due to a number of factors, including the level of domestic production volumes and infrastructure limitations which impact pricing and geopolitical developments. Based on market and industry conditions throughout 2011 and conditions in early 2012, it appears domestic crude oil and NGL production levels and refined products exports could exceed the EIA s forecast over the next several years.

	Actual	**Projected**			
	2011	**2012**	**2013**	**2015**	**2020**
	(in millions of barrels per day)				
Supply					
Domestic Crude Oil Production	5.7	5.9	6.0	6.3	6.7
Net Imports - Crude Oil	9.1	8.9	8.6	8.5	7.4
Crude Oil Input to Domestic Refineries	14.8	14.8	14.6	14.8	14.1
Product Imports	2.3	2.4	2.1	2.1	2.0
Product Exports	(2.6)	(2.4)	(2.3)	(2.3)	(2.0)
Net Product Imports	(0.3)		(0.2)	(0.2)	

Supply from Renewable Sources	0.8	1.0	1.0	1.1	1.3
Other - (NGL Production, Refinery Processing Gain)	3.8	3.3	3.5	3.6	4.0
Total Domestic Petroleum Consumption	19.1	19.1	18.9	19.3	19.4

As illustrated in the table above, imports of foreign crude oil and other petroleum products play a major role in achieving a balanced U.S. market on an aggregate basis. However, because of the substantial number of different grades and varieties of crude oil and their distinguishing physical and economic properties and the distinct configuration of each refinery s process units, significant logistics infrastructure and services are required to balance the U.S. market on a region by region basis.

By way of illustration, the Department of Energy segregates the United States into five Petroleum Administration Defense Districts (PADDs), which are used by the energy industry for reporting statistics regarding crude oil supply and demand. The table below sets forth supply, demand and shortfall information for each PADD for the twelve months ended October 2011 and is derived from information published by the EIA (see EIA website at *www.eia.doe.gov*):

Petroleum Administration Defense District (in millions of barrels per day)	**Regional Supply**	**Refinery Demand**	**Supply Shortfall**
PADD I (East Coast)		1.1	(1.1)
PADD II (Midwest)	0.8	3.3	(2.5)
PADD III (South)	3.3	7.5	(4.2)
PADD IV (Rockies)	0.4	0.5	(0.1)
PADD V (West Coast)	1.2	2.4	(1.2)
Total U.S.	5.7	14.8	(9.1)

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As a result of advances in horizontal drilling and fracturing technology over the last several years and their application to various large scale resource plays, certain historical trends are being influenced. For example, PADD II production increased beginning in 2005 and as of early 2012 is estimated to be over 800,000 barrels per day, nearly double 2004 s level. This increase is being driven mainly by increased production from the Bakken oil formation in North Dakota using advanced horizontal drilling and fracturing technology.

More recently, other parts of the U.S. have experienced increased production volumes from mature producing areas such as the Rockies, the Permian Basin in West Texas, as well as less developed areas such as the Eagle Ford Shale in South Texas. Actual and anticipated production increases in multiple areas combined with actual and expected increased imports from Canada has strained or is expected to strain existing transportation and terminalling infrastructure in multiple areas. These developments are also resulting in changes to historical trends with respect to crude oil movements between regions of the U.S. For example, the quantity of crude oil transported from the Gulf Coast area into PADD II has declined, but the overall change in crude oil flows has resulted in an increased demand for storage and terminalling services at Cushing, Oklahoma and Patoka, Illinois.

The quality of the increasing crude oil volumes, which are generally lighter (higher gravity) and sweeter (lower sulfur content) than previous production, is exacerbating the demands placed on existing infrastructure. Notably, this change in crude oil quality is in stark contrast to the sizeable, multi-year investments made by a number of U.S. refining companies in order to expand their capabilities to process heavier, sourer grades of crude oil, which caused differentials between crude oil grades and qualities to change relative to historical levels and become much more dynamic and volatile. The combination of (i) a significant increase in North American production volumes, (ii) a change in crude oil qualities and related differentials and (iii) a high utilization of existing pipeline and terminal infrastructure have stimulated multiple industry initiatives to build new pipeline and terminal infrastructure, convert certain pipeline assets to alternative service or reverse flows and expand the use of trucks, rail and barges for the movement of crude oil.

Overall, volatility in various aspects of the crude oil market including absolute price, market structure and grade and location differentials has increased over time and we expect this volatility to persist. Some factors that we believe are causing and will continue to cause volatility in the market include:

- the multi-year narrowing of the gap between supply and demand in North America;
- fluctuations in international supply and demand related to the economic environment, geopolitical events and armed conflicts;
- regional supply and demand imbalances and changes in refinery capacity and specific capabilities;
- significant fluctuations in absolute price as well as grade and location differentials;
- political instability in critical producing nations; and

- policy decisions made by various governments around the world attempting to navigate energy challenges.

The complexity and volatility of the crude oil market creates opportunities to solve the logistical inefficiencies inherent in the business.

Refined Products Market Overview

After transport to a refinery, the crude oil is processed into different petroleum products. These refined products fall into three major categories: transportation fuels such as motor gasoline and distillate fuel oil (diesel fuel and jet fuel); finished non-fuel products such as solvents, lubricating oils and asphalt; and feedstocks for the petrochemical industry such as naphtha and various refinery gases. Demand is greatest for transportation fuels, particularly motor gasoline.

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

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

Demand for refined products has generally been affected by price levels, economic growth trends, conservation, fuel efficiency mandates and, to a lesser extent, weather conditions. According to the EIA, petroleum consumption in the United States rose from approximately 15.7 million barrels per day in 1985 to an average of approximately 20.7 million barrels during the four-year period ending with 2007. From 2008 through the 12 months ended October 2011, petroleum consumption averaged approximately 19.1 million barrels per day, an approximate 8% decrease from peak levels, largely due to the economic weakness. Given this decreased demand for refined products, the increased use of ethanol and other renewable fuels and the resulting excess refining capacity, a number of U.S. refineries reduced output and, in some cases, indefinitely shut-down. The EIA is currently forecasting growth in overall refined product demand to increase marginally over the next decade.

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The level of future domestic demand generally will be influenced by the slope of the economic recovery as well as the absolute prices of the products. Counteracting the impact of decreased domestic refined product demand on many U.S. refineries has been the combination of a significant decrease in refined product imports and a significant increase in refined product exports. Refined product imports decreased from 3.2 million barrels per day in 2005 to an average of approximately 2.3 million barrels per day for the twelve months ended October 2011. Conversely, refined product exports increased from approximately 1.1 million barrels in 2005 to 2.6 million barrels for the twelve months ended October 2011. We believe that potential demand growth will be met primarily by the increase in mandated alternative fuels and increased utilization of existing refining capacity, the combination of which we believe will generate demand for midstream infrastructure, including pipelines and terminals. We believe that demand for refined products pipeline and terminalling infrastructure will also be driven by the following factors:

- multiple specifications of existing products (also referred to as boutique gasoline blends);
- continued specification changes to existing products, such as lower sulfur limits; and
- increased acceptance and mandates of biofuels and other related renewable fuels.

The complexity and volatility of the refined products market creates opportunities to solve the logistical challenges inherent in the business.

NGL Market Overview

NGLs primarily include ethane, propane, normal butane, iso-butane, and natural gasoline, and are derived from natural gas production and processing activities as well as crude oil refining processes. LPG primarily includes propane and butane which liquefy at moderate pressures thus making it easier to transport and store such products. As discussed above, the terms NGL and LPG are sometimes used interchangeably depending upon the context.

NGL Demand. Individual NGL products have varying uses. Described below are the five basic NGL components and their typical uses:

- *Ethane.* Ethane accounts for the largest portion of the NGL barrel and substantially all of the extracted ethane is used as feedstock in the production of ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. When ethane recovery from a wet natural gas stream is uneconomic, ethane is also left in the gas stream to be burned as fuel, subject to pipeline specifications.

- *Propane.* Propane is used as heating fuel, engine fuel and industrial fuel, for agricultural burning and drying and also as petrochemical feedstock for the production of ethylene and propylene.

- *Normal butane.* Normal butane is principally used for motor gasoline blending and as fuel gas, either alone or in a mixture with propane, and feedstock for the manufacture of ethylene and butadiene, a key ingredient of synthetic rubber. Normal butane is also used to derive iso-butane.

- *Iso-butane.* Iso-butane is principally used by refiners to produce alkylates to enhance the octane content of motor gasoline

- *Natural Gasoline.* Natural gasoline is principally used as a motor gasoline blend stock or as a petrochemical feedstock.

Certain NGLs, primarily natural gasoline and butane, are also used as diluents in the transportation of heavy crude oil (bitumen), particularly in Canada.

NGL Supply. The bulk (approximately 71%) of the U.S. NGL supply comes from gas processing plants, which separate a mixture of NGL from the dry gas (primarily methane). The NGL mix (also referred to as Y Grade) is then either fractionated at the processing site into the individual components (known as purity products), which may be transported, stored and sold to end use markets or transported as a Y-Grade to a regional fractionation facility.

The majority of gas processing plants in the U.S. are located along the Gulf Coast, in the West Texas/Oklahoma area and in the Rockies region. Smaller gas processing regions are located in Michigan and Illinois as well as the Marcellus region (which is expanding rapidly) and Southern California. In Canada, the vast majority of the processing capacity is located in Alberta, with a much smaller (but increasing) amount in British Columbia.

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NGL products from refineries represent approximately 20% of U.S. supply and are by-products of the refinery conversion processes. Consequently, they have generally already been separated into individual components and do not require further fractionation. NGL products from refineries are principally propane, with lesser amounts of butane, refinery naphthas (products similar to natural gasoline) and ethane. Due to refinery maintenance schedules and butane blending considerations, refinery production of propane and butane varies on a seasonal basis.

NGLs are also imported into certain regions of the U.S. from Canada and other parts of the world (approximately 9% of total supply). NGLs (primarily propane) are also exported from certain regions of the United States.

NGL Transportation and Trading Hubs. NGLs, whether as a mixture or as purity products, are transported by pipelines, barges, rail cars and tank trucks. The method of transportation used depends on, among other things, the resources of the transporter, the locations of the production points and the delivery points, cost-efficiency and the quantity of product being transported. Pipelines are generally the most cost-efficient mode of transportation when large, consistent volumes of product are to be delivered.

The major NGL infrastructure and trading hubs in North America are located at Mont Belvieu, Texas; Conway, Kansas; Edmonton, Alberta; and Sarnia, Ontario. Each of these hubs contains a critical mass of infrastructure, including fractionators, storage, pipelines and access to end markets, particularly Mont Belvieu. Pricing at these hubs is relatively transparent and is tracked in several industry publications. In addition, there are several other hubs, including Empress and Fort Saskatchewan, Alberta and Hobbs, New Mexico. The West Virginia/Western Pennsylvania area is also rapidly developing as a meaningful NGL infrastructure hub.

NGL Storage. NGLs must be stored under pressure to maintain their liquid state. The lighter the product (e.g., ethane), the greater the pressure that must be maintained. Large volumes of NGLs are stored in underground caverns constructed in salt or granite. Product is also stored in above ground tanks. Natural gasoline can be stored at relatively low pressures in tankage similar to that used to store motor gasoline. Propane and butane are stored at much higher pressures in steel spheres, cylinders, bullets or other configurations. Ethane is stored at very high pressures, typically in salt caverns. Storage is especially important for NGLs as supply and demand can vary materially on a seasonal basis.

NGL Market Outlook. NGL supplies from gas processing plants are increasing rapidly due to the increased drilling activity in unconventional resource plays, where producers are targeting liquids rich areas to capitalize on high NGL product prices (which historically have been correlated with crude oil prices). Numerous industry and financial analysts project NGL supply volumes will continue to grow over the next several years with some analysts projecting U.S. supply volumes to increase from current levels by as much as 40% by 2016. A significant amount of this volume is expected to come from recently discovered, unconventional resource plays which do not have the NGL infrastructure to process the wet natural gas or transport, fractionate, and store the NGL products. Nor are these new supply areas near historical markets for the NGL purity products. As a result of these dynamics, substantial incremental infrastructure is likely to be developed throughout the NGL value chain over the next several years. A portion of the increased supply of product will likely be absorbed by the domestic petrochemical sector as low cost feed stocks. In addition, growing production of Canadian heavy crude oil is likely to create demand for additional diluents, primarily natural gasoline and butane. The remaining product not absorbed domestically will likely drive continued growth in the LPG export market. The NGL market is, among other things, expected to be driven by:

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- the absolute prices of NGL products and their prices relative to natural gas;
- drilling activity and wet natural gas production in developing liquids-rich production areas;
- production growth/decline rates of wet natural gas in established supply areas;
- available processing, fractionation, storage and transportation capacity;
- infrastructure development costs and timing as well as development risk sharing;
- the cost of acquiring processing rights (e.g. extraction premiums) from producers to process their gas;
- petro-chemical demand;
- diluent requirements for Canadian heavy oil;
- international demand for LPG products;
- regulatory changes in gasoline specifications affecting demand for butane;
- refinery shut downs;
- alternating needs of refineries to store and blend LPG;
- seasonal shifts in weather; and

- inefficiencies caused by regional supply and demand imbalances.

As a result of these and other factors, the NGL market is complex and volatile, which along with expected market growth creates opportunities to solve the logistical inefficiencies inherent in the business.

Natural Gas Storage Market Overview

North American natural gas storage facilities provide a staging and warehousing function for seasonal swings in demand relative to supply, as well as an essential reliability cushion against disruptions in natural gas supply, demand and transportation. Natural gas storage (and to a lesser extent imported natural gas from Canada) serves as the shock absorber that balances the market, serving as a source of supply to meet the consumption demands in excess of daily production capacity and a warehouse for gas production in excess of daily demand during low demand periods.

The market for natural gas storage services in the United States is driven by:

- the long-term supply and demand for natural gas and the overall lack of balance between the supply of and demand for natural gas on a seasonal, monthly, daily or other basis;

- natural gas demand from seasonal or weather-sensitive end-users such as gas-fired power generators and residential and commercial consumers;

- any factors that contribute to more frequent and severe imbalances between the supply of and demand for natural gas, whether caused by supply or demand fluctuations;

- operational imbalances, near term seasonal spreads, shorter term spreads and basis differentials; and

- the extent to which there is a surplus or shortfall of storage capacity relative to the overall demand for storage services in a given market area.

During the period from 2001 through 2011, domestic natural gas consumption has grown, albeit unevenly, primarily as a result of growth in the seasonal and weather-sensitive electric power generation and commercial sectors. This growth was offset by declines in the residential and industrial sectors. For a number of years during the same period, domestic natural gas production was relatively flat and failed to keep pace with domestic consumption. Over the past several years, however, domestic natural gas production has been growing rapidly, primarily due to significant increases in production from developing shale resource plays.

The seasonality of natural gas demand has remained strong during the last decade, with consumption during the peak winter months averaging approximately 40% more than consumption during the summer months, per EIA data. This strong seasonal trend has produced seasonal spreads (the price difference between the summer and winter season) that have generally moved within a range of approximately $0.37-$4.75 per MMBtu, with the high end of that range occurring during the 2006-2007 timeframe. However, in 2011 the seasonal spreads (Oct-Jan) traded in a range of approximately $0.37-$0.62. While there are a variety of factors that have contributed to these softer market conditions, we believe the key drivers are (i) relatively flat natural gas consumption over the last year (and projected flat consumption for the next several years), (ii) increased natural gas supplies due to production from shale resources, (iii) net increases in storage capacity and (iv) lower basis differentials due to expansion of natural gas transportation infrastructure in the U.S. over the last five years. We believe that certain of the supply and demand factors are cyclical and self correcting over time, and that the long term outlook for storage utilization and demand is positive.

Description of Segments and Associated Assets

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

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

Transportation Segment

Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and refined products on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third party leases of pipeline capacity and transportation fees. Our transportation segment also includes our equity earnings from our investments in Settoon Towing, White Cliffs, Butte and Frontier, in which we own noncontrolling interests.

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As of December 31, 2011, we employed a variety of owned or leased long-term physical assets throughout the United States and Canada in this segment, including approximately:

- 16,000 miles of active crude oil and refined products pipelines and gathering systems;
- 23 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;
- 67 trucks and 382 trailers; and
- 82 transport and storage barges and 44 transport tugs through our interest in Settoon Towing.

The following is a tabular presentation of our active pipeline assets in the United States and Canada as of December 31, 2011, grouped by geographic location:

Region / Pipeline and Gathering Systems (1)	**System Miles**	**2011 Average Net Barrels per Day (2) (in thousands)**
Southwest US		
Basin	521	440
Permian Basin Area Systems	2,969	404
Other	162	127
Southwest US Subtotal	**3,652**	**971**
Western US		
All American	138	35
Line 63/Line 2000	362	114
Other	150	82
Western US Subtotal	**650**	**231**
US Rocky Mountain		
Salt Lake City Area Systems	731	137
Other	3,972	348
US Rocky Mountain Subtotal	**4,703**	**485**
US Gulf Coast		
Capline(3)	631	160
Other	1,089	326
US Gulf Coast Subtotal	**1,720**	**486**
Central US		
Mid-Continent Area Systems	2,023	213
Other	376	132
Central US Subtotal	**2,399**	**345**
Domestic Total	**13,124**	**2,518**

Canada		
Rangeland	1,221	59
Rainbow	594	135
Manito	555	66
Other	612	164
Canada Total	**2,982**	**424**
Grand Total	**16,106**	**2,942**

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

(2) Represents average volume for the entire year.

(3) Non-operated pipeline.

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Southwest US

Basin Pipeline System. We own an approximate 87% undivided joint interest in and are the operator of the Basin Pipeline system. The Basin system is a primary route for transporting crude oil from the Permian Basin (in west Texas and southern New Mexico) to Cushing, Oklahoma, for further delivery to Mid-Continent and Midwest refining centers. The Basin system is a 521-mile mainline, telescoping crude oil system with a system 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 440,000 barrels per day (attributable to our interest) during 2011.

The Basin system consists of four primary movements of crude oil: (i) barrels that are shipped from Jal, New Mexico to the West Texas markets of Wink and Midland; (ii) barrels that are shipped from Midland to connecting carriers at Colorado City; (iii) barrels that are shipped from Midland and Colorado City to connecting carriers at either Wichita Falls or Cushing and (iv) foreign and Gulf of Mexico barrels that are delivered into Basin at Wichita Falls and delivered to connecting carriers at Cushing. The system also includes approximately 6 million barrels of tankage located along the system. The Basin system is subject to tariff rates regulated by the FERC.

Permian Basin Area Systems. We operate wholly owned systems of approximately 3,000 miles that aggregate receipts from wellhead gathering lines and bulk truck injection locations into a combination of 4- to 16-inch diameter trunk lines for transportation and delivery into the Basin system at Jal, Wink and Midland as well as our terminal facilities in Midland, Texas. These systems are subject to tariff rates regulated by either the FERC or state regulatory agencies. For 2011, combined throughput on the Permian Basin area systems totaled an average of approximately 404,000 barrels per day.

Western US

All American Pipeline System. We own a 100% interest in the All American Pipeline system. The All American Pipeline is a common carrier crude oil pipeline system that transports crude oil produced from two outer continental shelf, or OCS, fields offshore California via connecting pipelines to refinery markets in California. The system at Las Flores receives crude oil from ExxonMobil s Santa Ynez field, while the system at Gaviota receives crude oil from the Plains Exploration and Production Company-operated Point Arguello field. These systems both terminate at our Emidio Station. Between Gaviota and our Emidio Station, the All American Pipeline interconnects with our San Joaquin Valley Gathering System, Line 2000 and Line 63, as well as other third party intrastate pipelines. The system is subject to tariff rates regulated by the FERC.

A portion of our transportation segment profit on Line 63 and Line 2000 is derived from the pipeline transportation business associated with the Santa Ynez and Point Arguello fields and fields located in the San Joaquin Valley. Volumes shipped from the OCS are in decline (as reflected in the table below). See Item 1A. Risk Factors for discussion of the estimated impact of a decline in volumes.

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

	For the Year Ended December 31,				
	2011	2010	2009	2008	2007

Average daily volumes received from:					
Point Arguello (at Gaviota)	5	6	6	7	8
Santa Ynez (at Las Flores)	30	33	34	38	38
Total	35	39	40	45	46

Line 63. We own a 100% interest in the Line 63 system. The Line 63 system is an intrastate common carrier crude oil pipeline system that transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. The Line 63 system consists of a 144-mile trunk pipeline (of which 102 miles is 14-inch pipe and 42 miles is 16-inch pipe), originating at our Kelley Pump Station in Kern County, California and terminating at our West Hynes Station in Long Beach, California. The trunk pipeline has a capacity of approximately 110,000 barrels per day. The Line 63 system includes 5 miles of distribution pipelines in the Los Angeles Basin, with a throughput capacity of approximately 144,000 barrels per day, and 148 miles of gathering pipelines in the San Joaquin Valley, with a throughput capacity of approximately 72,000 barrels per day. We also have approximately 1 million barrels of storage capacity on this system. These storage assets are used primarily to facilitate the transportation of crude oil on the Line 63 system.

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During the fourth quarter of 2009, a 71-mile segment of Line 63 was temporarily taken out of service to allow for certain repairs and realignments to be performed. Line 63 volumes are currently being redirected from the north end of this out-of-service segment to the parallel Line 2000. The product is then batched along Line 2000 until it is re-injected into the active portion of Line 63, which is south of the out-of-service segment, for subsequent delivery to customers. This temporary pipeline segment closure and redirection of product has not impacted our normal throughput levels on this line. For 2011, combined throughput on Line 63 totaled an average of approximately 61,000 barrels per day.

Line 2000. We own and operate 100% of Line 2000, an intrastate common carrier crude oil pipeline that originates at our Emidio Pump Station (part of the All American Pipeline System) and transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin. Line 2000 is a 130-mile, 20-inch trunk pipeline with a throughput capacity of approximately 130,000 barrels per day. During 2011, throughput on Line 2000 (excluding Line 63 volumes) averaged approximately 53,000 barrels per day.

US Rocky Mountain

Salt Lake City Area Systems. We operate the Salt Lake City Area systems, in which we own interests of between 75% and 100%. The Salt Lake City Area systems include interstate and intrastate common carrier crude oil pipeline systems that transport crude oil produced in Canada and the U.S. Rocky Mountain region to refiners in Salt Lake City, Utah and to other pipelines at Ft. Laramie, Wyoming. The Salt Lake City Area systems consist of 731 miles of pipelines and approximately 1 million barrels of storage capacity. These systems have a maximum throughput capacity of (i) approximately 20,000 barrels per day from Wamsutter, Wyoming to Ft. Laramie, Wyoming, (ii) approximately 49,000 barrels per day from Wamsutter, Wyoming to Wahsatch, Utah and (iii) approximately 120,000 barrels per day from Wahsatch, Utah to Salt Lake City, Utah. For 2011, throughput on the Salt Lake City Area systems in total averaged approximately 137,000 barrels per day.

US Gulf Coast

Capline Pipeline System. The Capline Pipeline system, in which we own an aggregate undivided joint interest of approximately 54%, is a 631-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. We also own a 100% interest in approximately 720,000 barrels of tankage located at Patoka, Illinois.

Shell Pipeline Company LP is the operator of this system through August 2013. Capline has direct connections to a significant amount of crude production in the Gulf of Mexico. In addition, it has two active docks capable of handling approximately 600,000-barrel tankers and is connected to the Louisiana Offshore Oil Port and our St. James terminal and transports sweet and light sour foreign crude to PADD II. Total designed operating capacity is approximately 1.1 million barrels per day of crude oil, of which our attributable interest is approximately 600,000 barrels per day. Throughput on our interest averaged approximately 160,000 barrels per day during 2011.

Central US

Mid-Continent Area Systems. We own and operate pipeline systems that source crude oil from the Cleveland Sand, Granite Wash and Mississippian/Lime resource plays of Western and Central Oklahoma, Southwest Kansas and the eastern Texas Panhandle. These systems consist of over 2,000 miles of pipeline with transportation and delivery into and out of our terminal facilities at Cushing. For 2011, combined throughput on the Mid-Continent Area systems totaled an average of approximately 213,000 barrels per day.

Canada

Rangeland System. We own a 100% interest in the Rangeland system. The Rangeland system consists of a 554 mile, 8-inch to16-inch mainline pipeline and 667 miles of 3-inch to 8-inch gathering pipelines. The Rangeland system transports NGL mix, butane, condensate, light sweet crude and light sour crude either north to Edmonton, Alberta or south to the U.S./Canadian border near Cutbank, Montana, where it connects to our Western Corridor system. Total average throughput during 2011 on the Rangeland system was approximately 59,000 barrels per day.

Rainbow System. We own a 100% interest in the Rainbow system. The Rainbow system consists of a 480-mile, 20-inch to 24-inch mainline crude oil pipeline extending from the Norman Wells Pipeline located in Zama, Alberta to Edmonton, Alberta and 114 miles of gathering pipelines. The system has a throughput capacity of approximately 220,000 barrels per day and transported approximately 135,000 barrels per day during 2011.

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Manito. We own a 100% interest in the Manito heavy oil system. This 555-mile system is comprised of the Manito pipeline, the North Sask pipeline and the Bodo/Cactus Lake pipeline. Each system consists of a blended crude oil line and a parallel diluent line which delivers condensate to upstream blending locations. The North Sask pipeline is 84 miles in length and originates near Turtleford, Saskatchewan and terminates in Dulwich, Saskatchewan. The Manito pipeline includes 334 miles of pipeline, and the mainline segment originates at Dulwich and terminates at Kerrobert, Saskatchewan. The Bodo/Cactus Lake pipeline is 137 miles long and originates in Bodo, Alberta and also terminates at our Kerrobert storage facility. The Kerrobert storage and terminalling facility is connected to the Enbridge pipeline system and can both receive and deliver heavy crude from and to the Enbridge pipeline system. For 2011, approximately 66,000 barrels per day of crude oil were transported on the Manito system.

Pipeline and Gathering Systems Under Construction and Under Development

Basin System Expansion. During 2011, we commenced two expansion projects on the Basin system to increase pipeline capacity. Capacity on crude oil movements from Colorado City, Texas to Cushing, Oklahoma will be increased from 400,000 to approximately 450,000 barrels per day and capacity on the segment from Hendrick to Midland will be increased from 145,000 to approximately 240,000 barrels per day. These projects are expected to be completed in the second quarter of 2012.

Rainbow II Pipeline Expansion. During 2011, we commenced an expansion project for the construction of a 187-mile pipeline to transport condensate and butane from Edmonton, Alberta to our Nipisi truck terminal. Subject to regulatory approval, we expect the project to be in service by the second half of 2013.

Bone Spring Project. During the second quarter of 2011, we commenced construction of an expansion project serving the Bone Spring play in West Texas. The project includes adding six miles of new 6 pipe to an existing system and constructing 20 miles of new 12 pipe and 15 miles of new 10 pipe. The project is designed to initially transport up to approximately 65,000 barrels per day of crude oil and will provide additional take-away capacity for emerging production in Reeves and Ward counties in West Texas. These pipelines will interconnect with our Basin system at Hendrick. We also are constructing up to approximately 100,000 barrels of new storage and terminalling capacity that will be brought on-line in stages. The project is expected to be in service by the first quarter of 2012.

Eagle Ford Area Projects. During 2011, we commenced construction of a new 130-mile crude oil and condensate pipeline, a marine terminal facility and 1.5 million barrels of storage capacity to service Eagle Ford production in South Texas. The project is designed to provide approximately 300,000 barrels per day of take-away capacity from the western region of the Eagle Ford play to Corpus Christi, Texas refining markets and other Gulf Coast markets and is supported by a long-term throughput agreement. PAA has agreed to provide Chesapeake Midstream Development, L.P. the opportunity to acquire up to a 25% joint ownership interest in the project. Additionally, PAA and Flint Hills Resources have executed a Memorandum of Understanding regarding Flint Hills potential joint ownership in this project. We expect to have a 50% ownership interest in this pipeline system, and anticipate it to be in service during the fourth quarter of 2012.

During November 2011, we acquired from Velocity a condensate and crude oil gathering and pipeline system (the Gardendale Gathering System) that is in the advanced stages of construction in the Eagle Ford area of South Texas. The Gardendale Gathering System consists of 120 miles of pipeline with an initial capacity of approximately 150,000 barrels per day and terminals at Gardendale and Catarina with aggregate storage capacity of approximately 185,000 barrels. We have commenced projects to (i) complete current construction, (ii) extend the system to access additional condensate barrels and other crude oil-oriented portions of the Eagle Ford play, and (iii) increase terminal capacity at Gardendale from 150,000 barrels to approximately 250,000 barrels. These expansion activities are expected to be completed at various stages over the next 18 to 24 months.

Bakken Area Projects. During 2011, we commenced a series of projects to service crude oil production in the Bakken region. Such projects include (i) the reversal of our currently idle Wascana Pipeline System, which is expected to be in service during the third quarter of 2012, (ii) the proposed construction of the Bakken North Pipeline System, a 80-mile, 12-inch crude oil pipeline with an initial design capacity of approximately 50,000 barrels that will extend from Trenton, North Dakota to the southern end of the Wascana pipeline, which, subject to regulatory approval and timely receipt of applicable permits, we anticipate placing into service in the fourth quarter of 2012, and (iii) the construction of a multi-use rail facility at Ross, North Dakota, with expected completion by the fourth quarter of 2012.

Medford-to-Cushing Pipeline. In January 2012, we completed the conversion of an existing Oklahoma LPG pipeline into crude oil service. The pipeline extends from Medford, Oklahoma to our terminal facility at Cushing. The pipeline provides an initial crude oil throughput capacity of 12,000 barrels per day and will be expanded to 25,000 barrels per day by July 2012.

Mississippian Lime Pipeline. In early 2012, we announced plans to construct a new 170-mile pipeline to service the increasing Mississippian Lime crude oil production in northern Oklahoma and Southern Kansas. This pipeline will be designed to provide approximately 150,000 barrels per day (approximately 175,000 barrels per day in conjunction with the Medford-to-Cushing pipeline conversion) of crude oil transportation to our terminal facilities at Cushing and is expected to be completed in mid-2013.

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Facilities Segment

Our facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products, LPG and natural gas, LPG fractionation and isomerization services and natural gas processing services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements. Revenues generated in this segment include (i) storage fees that are generated when we lease storage capacity, (ii) terminalling fees, or throughput fees, that are generated when we receive crude oil, refined products or LPG from one connecting pipeline and redeliver the applicable product to another connecting carrier, (iii) hub service fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing services, (iv) revenues from the sale of natural gas, (v) fees from LPG fractionation and isomerization and (vi) fees from gas processing services.

As of December 31, 2011, we owned, operated and employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 71 million barrels of crude oil and refined products storage capacity primarily at our terminalling and storage locations;
- approximately 9 million barrels of NGL/LPG storage capacity;
- approximately 76 Bcf of natural gas storage working capacity;
- approximately 14 Bcf of base gas in storage facilities owned by us;
- a fractionation plant in Canada with a processing capacity of approximately 4,400 barrels per day, and a fractionation and isomerization facility in California with an aggregate processing capacity of approximately 26,000 barrels per day; and
- four natural gas processing plants located in the Gulf Coast area.

The following is a tabular presentation of our active facilities segment storage and service assets in the United States and Canada as of December 31, 2011, grouped by product and service type and capacity and throughput as indicated:

Crude Oil and Refined Products Storage Capacity (Capacity in millions of barrels)	
Cushing	19
Kerrobert	1
LA Basin	9
Martinez and Richmond	5
Mobile and Ten Mile	3
Patoka	5
Philadelphia Area	4
St. James	7
Yorktown (1)	6
Other	12
	71
NGL/LPG Storage Capacity (Capacity in millions of barrels)	
Bumstead	2
Tirzah	1
Other	6
	9
NGL/LPG Fractionation and Isomerization (Average throughput in barrels per day)	
California (Fractionation and Isomerization) & Canada (Fractionation)	14,000
Natural Gas Storage Capacity (Capacity in billions of cubic feet)	
Salt-caverns (Pine Prairie and Southern Pines)	50
Depleted Reservoir (Bluewater)	26
	76
Gas Processing Facilities	N/A (2)

(1) Amount includes 1.6 million barrels of capacity for which we hold lease options (1.1 million barrels of which have been exercised).

(2) Volumes are not presented as they currently are not a significant driver of our segment results.

The following discussion contains a detailed description of our more significant facilities segment assets.

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Major Facilities Assets, Including Those Under Construction and Under Development

Crude Oil and Refined Products

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

Since 1999, we have completed multiple expansions, which have increased the capacity of the Cushing Terminal to a total of approximately 19 million barrels. During 2011, we completed our Phase IX, X and XI expansion projects. These projects included adding a new pipeline interconnect and approximately 4 million barrels of storage capacity through the construction of sixteen 270,000 barrel tanks.

Kerrobert Terminal. We own a crude oil and condensate storage and terminalling facility, which is located near Kerrobert, Saskatchewan and is connected to our Manito and Cactus Lake pipeline systems. The total storage capacity at the Kerrobert terminal is approximately 1 million barrels.

L.A. Basin. We own five crude oil and refined product storage facilities in the Los Angeles area with a total of approximately 9 million barrels of useable storage capacity and a distribution pipeline system of approximately 50 miles of pipeline in the Los Angeles Basin. Approximately 8 million barrels of the storage capacity are used for commercial service and approximately 1 million barrels are used primarily for throughput to other storage tanks and for displacement oil and do not generate revenue independently. We use the Los Angeles area storage and distribution system to service the storage and distribution needs of the refining, pipeline and marine terminal industries in the Los Angeles Basin. Our Los Angeles area system s pipeline distribution assets connect our storage assets with major refineries, our Line 2000 pipeline, and third-party pipelines and marine terminals in the Los Angeles Basin.

Martinez and Richmond Terminals. We own two terminals in the San Francisco, California area: a terminal at Martinez (which provides refined product and crude oil service) and a terminal at Richmond (which provides refined product service). Our San Francisco area terminals have approximately 5 million barrels of combined storage capacity that are connected to area refineries through a network of owned and third-party pipelines that carry crude oil and refined products to and from area refineries. The terminals have dock facilities and our Richmond terminal is also able to receive products by train.

Mobile and Ten Mile Terminal. We have a marine terminal in Mobile, Alabama (the Mobile Terminal) that has current useable capacity of approximately 2 million barrels. Approximately 3 million barrels of additional storage capacity is available at our nearby Ten Mile Facility, which is connected to our Mobile Terminal via a 36-inch pipeline. Approximately two-thirds of the storage capacity is included within the transportation segment.

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

Patoka Terminal. Our Patoka Terminal has approximately 5 million barrels of storage capacity and the associated manifold and header system at the Patoka Interchange located in southern Illinois. Patoka is a growing regional hub with access to domestic and foreign crude oil for certain volumes moving north on the Capline system as well as Canadian barrels moving south. Early in 2011, we commenced construction of Phase IV at our Patoka Terminal, which includes two 286,000 barrel crude oil tanks and one 400,000 barrel crude oil tank. This new tankage is expected to be completed in the second quarter of 2012.

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Philadelphia Area Terminals. We own four refined product terminals in the Philadelphia, Pennsylvania area. Our Philadelphia area terminals have a combined storage capacity of approximately 4 million barrels. The terminals have 20 truck loading lanes, two barge docks and a ship dock. The Philadelphia area terminals provide services and products to all of the refiners in the Philadelphia harbor, and include two dock facilities. The Philadelphia area terminals also receive products from connecting pipelines and offer truck loading services.

St. James Terminal. We have approximately 7 million barrels of crude oil storage capacity at the St. James crude oil interchange in Louisiana, which is one of the three most liquid crude oil interchanges in the United States. The facility includes a manifold and header system that allows for receipts and deliveries with connecting pipelines at their maximum operating capacity. Over the past few years, we completed the construction of a marine dock that is able to receive from tankers and receive from, and load, barges. The facility is also connected to a third party rail-unloading facility. The rail facility, which is exclusively connected to our St. James Terminal, has been expanded to unload 52 rail cars at a time and has capacity to unload 120,000 barrels of sweet crude oil per day. We are currently receiving approximately 60,000 barrels of crude oil per day by rail.

During the third quarter of 2011, we commenced our Phase IV expansion at the St. James Terminal. This project will include construction of an additional 1.0 million barrels of crude oil storage capacity. Completion of this expansion will bring total storage capacity at St. James to approximately 8 million barrels. The project is supported by multi-year contracts and throughput arrangements with third-party customers. We expect to complete Phase IV during the third quarter of 2012.

Yorktown Terminal. During the fourth quarter of 2011, we acquired the idled Western Refinery in Yorktown, Virginia and are operating it as a terminal. This facility has approximately 6 million barrels of storage for crude oil, black oil, propane, butane, and refined products, including 1.6 million barrels of capacity for which we hold lease options. The Yorktown facility has its own deep-water port on the York River with the capacity to service the receipt and delivery of product from ships and barges. This facility also has an active truck rack and rail capacity. We are in the process of making a number of modifications to the Yorktown facility, which will enhance the capabilities of the rail system, the dock facilities and increase connectivity and flexibility within the terminal itself. We expect to complete these projects by the second quarter of 2013.

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

The Environmental Impact Report (EIR) on this project was approved by the Board of Harbor Commissioners of the Port of Los Angeles on November 20, 2008. The EIR was challenged and on January 19, 2010, a final court ruling was issued in our favor. The California South Coast Air Quality Management District issued the Title V permits to construct and operate the facilities on October 6, 2011. Construction of the Pier 400 project is still subject to the completion and execution of a land lease with the Port of Los Angeles and the receipt of certain other regulatory approvals, as well as the completion of commercial arrangements with potential customers. We have approximately $95 million of capitalized project costs on our balance sheet as of December 31, 2011. We expect to be in a position in 2012 to determine whether or not we will develop this project.

NGL/LPG Storage Facilities

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

During 2010, we began upgrading and improving our Bumstead LPG storage facility, which will increase the useable capacity by approximately 700,000 barrels. This project is expected to be completed in mid-2012.

Tirzah. The Tirzah facility is located in South Carolina and consists of an underground granite storage cavern with approximately 1 million barrels of useable capacity. The Tirzah facility is connected to the Dixie Pipeline System (a third-party system) via our 62-mile pipeline.

NGL/LPG Fractionation and Isomerization

Shafter. Our Shafter facility located near Bakersfield, California provides isomerization and fractionation services to producers and customers of NGL. The primary assets consist of approximately 200,000 barrels of NGL storage and a processing facility with butane isomerization capacity of approximately 14,000 barrels per day and NGL fractionation capacity of approximately 12,000 barrels per day. During 2011, we commenced our Shafter Expansion Project. This project will include the construction of a 15-mile NGL pipeline system that will be capable of delivering up to 10,000 barrels per day from Occidental Petroleum Corporations s Elk Hills Gas plant to our Shafter facility. It will also include enhancements to our storage and rail facilities. The project is expected to be placed into service in the second quarter of 2013.

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Natural Gas Storage Facilities

Salt Cavern Storage Facilities. We own two FERC regulated, high deliverability salt cavern natural gas storage facilities located on the Gulf Coast. Our Pine Prairie facility is located in Evangeline, Rapides and Acadian Parishes, Louisiana and is permitted for up to 80 Bcf of working gas capacity, which includes 32 Bcf of incremental capacity that was recently approved by the FERC subject to the requirement that Pine Prairie conducts an open season consistent with applicable FERC policy. Our Southern Pines facility is located in Greene County, Mississippi and is permitted for up to 40 Bcf of working gas capacity. These two facilities had an aggregate working gas capacity as of December 31, 2011 of approximately 50 Bcf. During 2012, we anticipate placing an additional 16 Bcf of working gas capacity in service at these facilities, which will include a fifth cavern at Pine Prairie that is scheduled to be placed into service in the second quarter of 2012, a fourth cavern at Southern Pines that is scheduled to be placed into service in the third quarter of 2012 and additional capacity at both facilities from fill/dewater or solution mining under gas operations.

Both of these facilities are strategically-located and have attracted a diverse group of customers, including utilities, pipelines, producers, power generators, marketers and LNG importers, whose storage needs include both traditional seasonal storage services and short-term storage services. Pine Prairie is strategically positioned relative to several major market hubs, including the Henry Hub, the Carthage Hub and the Perryville Hub, and to existing and proposed LNG import and export facilities.

Pine Prairie s pipeline header system, which includes an aggregate of approximately 80 miles of 24-inch diameter pipe located within a 20-mile radius of Pine Prairie, is directly connected to eight large-diameter interstate pipelines through nine interconnects that service both conventional and unconventional natural gas production in Texas and Louisiana, including production from existing and emerging shale plays, as well as Gulf of Mexico production and LNG imports. These interconnects also provide direct or indirect access to each of the market hubs described above and to consumer and industrial markets in the Gulf Coast, Midwest, Northeast and Southeast regions of the United States. Pine Prairie s peak daily injection and withdrawal rates are 2.4 Bcf and 3.2 Bcf, respectively, and Pine Prairie has a total of 71,000 horsepower of compression capacity currently in service with another 27,500 horsepower of permitted capacity.

Southern Pines pipeline header system, which includes an aggregate of approximately 60 miles of 24-inch diameter pipe, is directly or indirectly connected to 8 major natural gas pipelines servicing the Gulf Coast, Northeast, Mid-Atlantic and Southeastern US markets. Southern Pines peak daily injection and withdrawal rates are 1.2 Bcf and 2.4 Bcf, respectively, and Southern Pines has a total of 48,000 horsepower of compression capacity currently in service.

Bluewater. Bluewater is located in the State of Michigan which contains more underground natural gas storage capacity than any other state in the U.S. according to EIA data. Bluewater primarily services seasonal storage needs throughout the Midwestern and northeastern portions of the U.S. and the Southeastern portion of Canada. Accordingly, Bluewater s customers consist primarily of pipelines, utilities and marketers seeking seasonal storage services. Bluewater s 30-mile, 20-inch diameter pipeline header system is supported by 13,350 horsepower of compression and connects with three interstate and three natural gas utility pipelines that provide access to the major market hubs of Chicago, Illinois and Dawn, Ontario, which supply natural gas to eastern Ontario and the northeastern United States. These interconnects also provide access to natural gas utilities that serve local markets in Michigan and Ontario. Bluewater s peak daily injection and withdrawal rates are 0.5 Bcf and 0.8 Bcf, respectively.

Bluewater has total working gas storage capacity of approximately 26 Bcf in two depleted reservoirs. Bluewater also leases third-party storage capacity and pipeline transportation capacity from time to time to increase its operational flexibility and enhance its service offerings. Bluewater has filed an application with the FERC to build a 20 pipeline that will be permitted for up to 300 MMcf per day and will connect its facility to a

Canadian pipeline owned by an affiliate of Spectra Energy. The proposed pipeline is intended to replace a 12 pipeline that is permitted for up to 250 MMcf per day and is currently leased from Nova Chemical through January 2013.

Natural Gas Processing

We own and operate four natural gas processing plants located in Louisiana and Alabama with an aggregate natural gas processing capacity of 1.2 Bcf per day. In early 2012, we announced plans to construct a cryogenic gas processing plant near Ross, North Dakota. The plant, if constructed, is expected to be sized to process 50 to 75 million cubic feet per day of gas and is scheduled to be in service in 2013.

Supply and Logistics Segment

Our supply and logistics segment operations generally consist of the following merchant related activities:

- the purchase of U.S. and Canadian crude oil at the wellhead and the bulk purchase of crude oil at pipeline and terminal facilities, as well as the purchase of waterborne cargoes at their load port and various other locations in transit;

- the storage of inventory during contango market conditions and the seasonal storage of LPG;

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- the purchase of LPG from producers, refiners and other marketers;
- the resale or exchange of crude oil and LPG at various points along the distribution chain to refiners or other resellers to maximize profits; and
- the transportation of crude oil and LPG on trucks, barges, railcars, pipelines and ocean-going vessels to various delivery points.

The majority of activities that are carried out within our supply and logistics segment are designed to produce a stable baseline of results in a variety of market conditions, while at the same time provide upside potential associated with opportunities inherent in volatile market conditions (including opportunities to benefit from fluctuating crude oil quality differentials). These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies to provide a balance. The tankage that is used to support our arbitrage activities positions us to capture margins in a contango market or when the market switches from contango to backwardation. See Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model below for further discussion.

In addition to substantial working inventories associated with its merchant activities, as of December 31, 2011, our supply and logistics segment also owned significant volumes of crude oil and LPG classified as long-term assets for linefill or minimum inventory requirements under service arrangements with transportation carriers and terminalling providers. The supply and logistics segment also employs a variety of owned or leased physical assets throughout the United States and Canada, including approximately:

- 9 million barrels of crude oil and LPG linefill in pipelines owned by us;
- 2 million barrels of crude oil and LPG linefill in pipelines owned by third parties and other long-term inventory;
- 622 trucks and 731 trailers; and
- 2,453 railcars (all of which are leased).

In connection with its operations, the supply and logistics segment secures transportation and facilities services from our other two segments as well as third-party service providers under month-to-month and multi-year arrangements. Intersegment sales are based on posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates. However, certain terminalling and storage rates recognized within our facilities segment are discounted to our supply and logistics segment to reflect the fact that these services may be canceled on short notice to enable the facilities segment to provide services to third parties, generally under longer term arrangements.

The following table shows the average daily volume of our supply and logistics activities for the year ended December 31, 2011 (in thousands of barrels per day):

	Volumes
Crude oil lease gathering purchases	742
LPG sales	103
Waterborne cargos	21
Supply & Logistics activities total	866

Crude Oil and LPG Purchases. We purchase crude oil and LPG from multiple producers under contracts and believe that we have established long-term, broad-based relationships with the crude oil and LPG producers in our areas of operations. These contracts generally range in term from a thirty-day evergreen to five years, with a limited number of contracts extending to ten years and the majority ranging from thirty days to one year. We utilize our truck fleet and gathering pipelines as well as leased railcars, third-party pipelines, trucks and barges to transport the crude oil to market. In addition, we purchase foreign crude oil. Under these contracts we may purchase crude oil upon delivery in the U.S. or we may purchase crude oil in foreign locations and transport it on third-party tankers.

We purchase LPG from producers, refiners, and other LPG marketing companies under contracts that generally range from immediate delivery to one year in term. We utilize our trucking fleet as well as leased railcars and third-party tank trucks or pipelines to transport LPG.

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

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

We sell our crude oil to major integrated oil companies, independent refiners and other resellers in various types of sale and exchange transactions. We sell LPG primarily to retailers and refiners, and limited volumes to other marketers. The contracts generally range in term from a thirty-day evergreen to three years, with a limited number of contracts extending to three years and the majority being approximately thirty-day to one year. We establish a margin for the crude oil and LPG we purchase by entering into physical sales contracts with third parties, or by entering into a future delivery obligation with respect to futures contracts on the NYMEX, ICE or over-the-counter. Through these transactions, we seek to maintain a position that is substantially balanced between purchases and sales and future delivery obligations. From time to time, we enter into various types of sale and exchange transactions including fixed price delivery contracts, floating price collar arrangements, financial swaps and crude oil and LPG-related futures contracts as hedging devices.

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

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

When we sell crude oil, LPG, refined products and natural gas, 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, prepayment, letters of credit and monitoring procedures.

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

We also have credit risk exposure related to our sales of LPG and natural gas; however, because our sales are typically in relatively small amounts to individual customers, we do not believe that these transactions pose a material concentration of credit risk. Typically, we enter into annual contracts to sell LPG on a forward basis, as well as to sell LPG on a current basis to local distributors and retailers. In certain cases our LPG customers prepay for their purchases, in amounts ranging up to 100% of their contracted amounts.

Certain activities in our supply and logistics segment are affected by seasonal aspects, primarily with respect to LPG supply and logistics activities, which generally have higher activity levels during the first and fourth quarters of each year.

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Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model

Through our three business segments, we are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products, LPG and natural gas. The majority of our activities are focused on crude oil, which is the principal feedstock used by refineries in the production of transportation fuels.

Crude oil, LPG, refined products and natural gas commodity prices have historically been very volatile. For example, over the last 24 years, NYMEX West Texas Intermediate crude oil benchmark prices have ranged from a low of approximately $10 per barrel during 1986 to a high of over $147 per barrel during 2008. During 2011, crude oil prices traded within a range of $75 to $115 per barrel.

Absent extended periods of lower crude oil prices that are below production replacement costs or higher crude oil prices that have a significant adverse impact on consumption, demand for the services we provide in our fee-based transportation and facilities segments and our gross profit from these activities have little correlation to absolute oil prices. Relative contribution levels will vary from quarter-to-quarter due to seasonal and other similar factors, but our fee-based transportation and facilities segments should comprise approximately 70% to 80% of our aggregate base level segment profit.

Base level segment profit from our supply and logistics activities is dependent on our ability to sell crude oil and LPG at prices in excess of our aggregate cost. Although segment profit may be adversely affected during certain transitional periods, our crude oil supply, logistics and distribution 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.

In developing our business model and allocating our resources among our three segments, we attempt to anticipate the impacts of shifts between supply-driven markets and demand-driven markets, seasonality, cyclicality, regional surpluses and shortages, economic conditions and a number of other influences that can cause volatility and change market dynamics on a short, intermediate and long-term basis. Our objective is to position the Partnership such that our overall annual base level of cash flow is not materially adversely affected by the absolute level of energy prices, shifts between demand-driven markets and supply-driven markets or other similar dynamics. We believe the complementary, balanced nature of our business activities and diversification of our asset base among varying regions and demand-driven and supply-driven markets provides us with a durable base level of cash flow in a variety of market scenarios.

In addition to providing a durable base level of cash flow, this approach is also intended to provide opportunities to realize incremental margin during volatile market conditions. For example, if crude oil prices are high relative to historical levels, we may hedge some of our expected pipeline loss allowance barrels, and if crude oil prices are low relative to historical prices, we may hedge part of the fuel needed to operate our trucks and barges. Also, during periods when supply exceeds the demand for crude oil, LPG or natural gas in the near term, the market for such product is often in contango, meaning that the price for future deliveries is higher than current prices. In a contango market, entities that have access to storage at major trading locations can purchase crude oil, LPG or natural gas at current prices for storage and simultaneously sell forward such products for future delivery at higher prices. Conversely, when there is a higher demand than supply of crude oil, LPG or natural gas in the near term, the market is backwardated, meaning that the price for future deliveries is lower than current prices. In a backwardated market, hedged positions established in a contango market can be unwound, with the physical product or futures position sold into the current higher priced market at a level that more than compensates for any loss associated with closing out future delivery obligations.

The combination of a high level of fee-based cash flow from our transportation and facilities segments, complemented by a number of diverse, flexible and counter-balanced sources of cash flow within our supply and logistics segment is intended to enable us to accomplish our objectives of maintaining a durable base level of cash flow and providing upside opportunities. In executing this business model, we employ a variety of financial risk management tools and techniques, predominantly in our supply and logistics segment.

Risk Management

In order to hedge margins involving our physical assets and manage risks associated with our various commodity purchase and sale obligations and, in certain circumstances, to realize incremental margin during volatile market conditions, we use derivative 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 management s assessment of the cost or benefit in doing so. Conversely, trading-related risks (the risks involved in trading in the hopes of generating an increased return) are not inherent in our core business; rather, those risks arise as a result of engaging in the trading activity. Our policy is to manage the enterprise level risks inherent in our core businesses, rather than trying to profit from trading activity. Our risk management policies and procedures are designed to monitor NYMEX, ICE and over-the-counter positions, as well

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as physical volumes, grades, locations, delivery schedules and storage capacity to help ensure that our hedging activities address our risks. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities and procedures and certain other aspects of corporate risk management. Our risk management function also approves all new risk management strategies through a formal process. Our approved strategies are intended to mitigate and manage enterprise level risks that are inherent in our core businesses.

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

Although we seek to maintain a position that is substantially balanced within our supply and logistics activities, we purchase crude oil, refined products, LPG and natural gas from thousands of locations and 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 and other uncontrollable events that occur within each month. When unscheduled physical inventory builds or draws do occur, they are monitored constantly and managed to a balanced position over a reasonable period of time. This activity is monitored independently by our risk management function and must take place within predefined limits and authorizations.

Geographic Data; Financial Information about Segments

See Note 13 to our Consolidated Financial Statements.

Customers

Marathon Petroleum Corporation and its affiliates accounted for approximately 16% of our revenues for the year ended 2011 and approximately 14% for each of the two years ended December 31, 2010 and 2009. ConocoPhillips Company accounted for approximately 10%, 10% and 12% of our revenues for the years ended December 31, 2011, 2010 and 2009, respectively. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2011, 2010 and 2009. The majority of revenues from these customers pertain to our supply and logistics operations. We believe that the loss of these customers would have only a short-term impact on our operating results. There is risk, however, that we would not be able to identify and access a replacement market at comparable margins. For a discussion of customers and industry concentration risk, see Note 8 to our Consolidated Financial Statements.

Competition

Competition among pipelines is based primarily on transportation charges, access to producing areas and demand for the crude oil by end users. We believe that high capital requirements, environmental considerations and the difficulty in acquiring rights-of-way and related permits make it unlikely that competing pipeline systems comparable in size and scope to our pipeline systems will be built in the foreseeable future. However, to the extent there are already third-party owned pipelines or owners with joint venture pipelines with excess capacity in the vicinity of our operations, we are exposed to significant competition based on the relatively low cost of moving an incremental barrel of crude oil. In addition, in areas where additional infrastructure is necessary to accommodate new or increased production or changing product flows, we face competition in providing the required infrastructure solutions as well as the risk of building capacity in excess of sustained demand.

We also face competition with respect to our supply and logistics and facilities services. Our competitors include other crude oil pipeline companies, the major integrated oil companies, their marketing affiliates and independent gatherers, banks that have established a trading platform, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources many times greater than ours, and control greater supplies of crude oil.

With respect to our natural gas storage operations, the principal elements of competition are rates, terms of service, supply and market access and flexibility of service. An increase in competition in our markets could arise from new ventures or expanded operations from existing competitors. Our natural gas storage facilities compete with several other storage providers, including regional storage facilities and utilities. Certain major pipeline companies and independent storage providers also have existing storage facilities connected to their systems that compete with some of our facilities.

Regulation

Our assets, operations and business activities are subject to extensive legal requirements and regulations under the jurisdiction of numerous federal, state, provincial and local agencies. Many of these agencies are authorized by statute to issue, and have issued, requirements binding on the pipeline industry, related businesses and individual participants. The failure to comply with such legal requirements and regulations can result in substantial penalties. At any given time there may be proposals, provisional rulings or proceedings in legislation or under governmental agency or court review that could affect our business. The regulatory burden on our assets, operations and activities increases our cost of doing business and, consequently, affects our profitability, but we

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do not believe that these laws and regulations affect us in a significantly different manner than our competitors. We may at any time also be required to apply significant resources in responding to governmental requests for information. In 2010 we settled by means of separate Consent Decrees, two ongoing Department of Justice (DOJ)/Environmental Protection Agency (EPA) proceedings regarding certain releases of crude oil. One Consent Decree applies to a specific system. The other (the General Consent Decree) applies to our crude oil pipelines in general. Although we believe that all material aspects of the injunctive elements of the Consent Decrees (costs and operational effects) have been incorporated into our budgeting and planning process, future proceedings could result in additional injunctive remedies, the effect of which would subject us to operational requirements and constraints that would not apply to our competitors.

The following is a discussion of certain, but not all, of the laws and regulations affecting our operations.

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 doing business, including our capital costs to construct, maintain and upgrade equipment and facilities. Failure to comply with these laws and regulations could result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, and the issuance of injunctions that may subject us to additional operational constraints that our competitors are not required to follow. Environmental and safety laws and regulations are subject to changes that may result in more stringent requirements, and we cannot provide any assurance that compliance with current and future laws and regulations will not have a material effect on our results of operations or earnings. A discharge of hazardous liquids into the environment could, to the extent such event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and any claims made by third parties. The following is a summary of some of the environmental and safety laws and regulations to which our operations are subject.

Pipeline Safety/Pipeline and Storage Tank Integrity Management

A substantial portion of our petroleum pipelines and our storage tank facilities in the United States are subject to regulation by the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to the Hazardous Liquids Pipeline Safety Act of 1979, as amended (the HLPSA). The HLPSA imposes safety requirements on the design, installation, testing, construction, operation, replacement and management of pipeline and tank facilities. Federal regulations implementing the HLPSA require pipeline operators to adopt measures designed to reduce the environmental impact of oil discharges from onshore oil pipelines, including the maintenance of comprehensive spill response plans and the performance of extensive spill response training for pipeline personnel. These regulations also require pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. Comparable regulation exists in some states in which we conduct intrastate common carrier or private pipeline operations. Regulation in Canada is under the National Energy Board (NEB) and provincial agencies.

United States

The HLPSA was amended by the Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act (PIPES Act) of 2006. These amendments have resulted in the adoption of rules by the Department of Transportation (DOT) that require transportation pipeline operators to implement integrity management programs, including more frequent inspections, correction of identified anomalies and other measures to ensure pipeline safety in high consequence areas, such as high population areas, areas unusually sensitive to environmental damage, and commercially navigable waterways. In the United States, our costs associated with the inspection, testing and correction of identified anomalies were approximately $32 million in 2011, $31 million in 2010, and $25 million in 2009. Based on currently available information, our preliminary estimate for 2012 is that we will incur approximately $14 million in operational expenditures and approximately $21 million in capital expenditures associated with our pipeline integrity management program. Significant additional expenses could be incurred if new or more stringently interpreted pipeline safety requirements are implemented. Currently, we believe our pipelines are in substantial compliance with HLPSA and the 2002 and 2006 amendments.

On December 13, 2011, the United States Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act). The President signed the Act into law on January 3, 2012. Under the Act, maximum civil penalties for certain violations have been increased from $100,000 to $200,000 per violation per day, and from a total cap of $1 million to $2 million. In addition, the Act reauthorizes the federal pipeline safety programs of PHMSA through September 30, 2015, and directs the Secretary of Transportation to undertake a number of reviews, studies and reports, some of which may result in additional natural gas and hazardous liquids pipeline safety rulemaking. Some of these directives include:

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- The Secretary of Transportation must revise regulations establishing time limits for notification of pipeline facility accidents and incidents to a minimum of not more than 1 hour after discovery of an accident or incident;

- The Secretary of Transportation must submit a report to Congress on leak detection systems utilized by operators and promulgate, where technically, operationally and economically feasible, regulations requiring leak detection systems where practicable;

- Within 12 months, the Secretary of Transportation must submit to Congress a report on the results of a study of hazardous liquid pipeline incidents at crossings of inland water bodies at least 100 feet wide, to determine if depth of cover over the buried pipe was a factor in any release of hazardous liquids;

- Within 12 months, the Secretary of Transportation must submit to Congress a report providing information on the total number of authorized full-time positions for pipeline inspection and enforcement at the PHMSA, the total number of positions not filled, the action being taken to fill the vacant positions and any additional inspection and enforcement resource needs of the PHMSA;

- Within 18 months, the Secretary of Transportation must conduct an evaluation to determine whether integrity management system requirements already in place for pipelines in High Consequence Areas (HCAs) should be expanded to pipelines beyond HCAs;

- Within two years, the Secretary of Transportation must submit to Congress a report on the results of a review of existing federal and state regulations for gas and hazardous liquid gathering lines located offshore, including within inlets of the Gulf of Mexico, for the purpose of determining whether the Secretary should issue regulations subjecting offshore gathering lines to the same standards and regulations as other hazardous liquid gathering lines; and

- Within two years, the Secretary of Transportation must determine whether to require the use of automatic or remote-controlled shut-off valves on new and entirely replaced transmission pipeline facilities.

A number of the provisions of the Act have the potential to cause owners and operators of pipeline facilities to incur significant capital expenditures and/or operating costs. Any additional requirements resulting from these directives are not expected to impact us differently than our competitors. We will work closely with our industry associations to participate with and monitor DOT-PHMSA s efforts.

In December 2009, PHMSA finalized a new rule dictating the shape and content of new control room management programs for hazardous liquid, gas transmission and distribution pipelines. The rule addresses human factors, including fatigue and other aspects of control room management for pipelines where controllers use supervisory control and data acquisition systems. The new rule became effective on February 1, 2010 and requires that control room management plans be written by August 1, 2011, which we completed on time. Implementation of certain aspects such as fatigue training for Controllers and Supervisors, Change Management, Operating Experience and establishing Shift Change procedures was required and completed by October 1, 2011. Implementation for the remaining aspects of the rule is required by August 1, 2012. We have already incorporated many of the new rule s requirements into our control room operations and we anticipate fully implementing the remaining provisions prior to the established deadline.

We have an internal review process in which we examine the condition and operating history of our pipelines and gathering assets to determine if any of our assets warrant additional investment or replacement. Accordingly, in addition to potential cost increases related to unanticipated regulatory changes or injunctive remedies resulting from U.S. EPA enforcement actions, we may elect (as a result of our own internal initiatives) to spend substantial sums to ensure the integrity of and upgrade our pipeline systems and, in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines.

If approved by PHMSA, states may assume responsibility for enforcing federal interstate pipeline regulations as agents for PHMSA and conduct inspections of intrastate pipelines. In practice, states vary in their authority and capacity to address pipeline safety. We do not anticipate any significant issues in complying with applicable state laws and regulations.

The DOT has issued guidelines with respect to securing regulated facilities against terrorist attack. We have instituted security measures and procedures in accordance with such guidelines to enhance the protection of certain of our facilities. We cannot provide any assurance that these security measures would fully protect our facilities from an attack.

The DOT has adopted American Petroleum Institute Standard 653 (API 653) as the standard for the inspection, repair, alteration and reconstruction of steel aboveground petroleum storage tanks subject to DOT jurisdiction. API 653 requires regularly scheduled inspection and repair of tanks remaining in service. In the United States, costs associated with this program were approximately $22 million, $25 million, and $22 million in 2011, 2010, and 2009, respectively. For 2012, we have budgeted approximately $32 million in connection with continued API 653 compliance activities and similar new EPA regulations for tanks not regulated by the DOT. Certain storage tanks may be taken out of service if we believe the cost of compliance will exceed the value of the storage tanks or replacement tankage may be constructed.

Canada

In Canada, the NEB and provincial agencies such as the Energy Resources Conservation Board (ERCB) in Alberta and the Saskatchewan Ministry of Energy and Resources regulate the construction, alteration, inspection and repair of crude oil storage tanks.

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We have incurred and will continue to incur costs under laws and regulations related to pipeline and storage tank integrity, such as operator competency programs, regulatory upgrades to our operating and maintenance systems and environmental upgrades of buried sump tanks. We spent approximately $35 million in 2011, $23 million in 2010, and $20 million in 2009 on these types of costs. Our preliminary estimate for 2012 is approximately $62 million.

Although we believe that our pipeline operations are in substantial compliance with currently applicable regulatory requirements (including the Consent Decrees, to the extent applicable), 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 (including the General Consent Decree) in the U.S. and Canada.

Occupational Safety and Health

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

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

Solid Waste

We generate wastes, including hazardous wastes, which are subject to the requirements of the federal Resource Conservation and Recovery Act, as amended, (RCRA) and analogous state and provincial laws. Many of the wastes that we generate are not subject to the most stringent requirements of RCRA because our operations generate primarily oil and gas wastes, which currently are excluded from consideration as RCRA hazardous wastes. It is possible, however, that in the future oil and gas wastes may be included as hazardous wastes under RCRA, in which event our wastes as well as the wastes of our competitors will be subject to more rigorous and costly disposal requirements, resulting in additional capital expenditures or operating expenses.

Hazardous Substances

The federal Comprehensive Environmental Response, Compensation and Liability Act, as amended (CERCLA), also known as Superfund, and comparable state laws impose liability, without regard to fault or the legality of the original act, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the site or sites where the release occurred and companies that disposed of, or arranged for the disposal of, the hazardous substances found at the site. 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. Canadian and provincial laws also impose liabilities for releases of certain substances into the environment.

Environmental Remediation

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

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.

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In conjunction with our acquisitions, we typically make an assessment of potential environmental exposure and determine whether to negotiate an indemnity, what the terms of any indemnity should be and whether to obtain environmental risk insurance, if available. These contractual indemnifications typically are subject to specific monetary requirements that must be satisfied before indemnification will apply, and have term and total dollar limits. For instance, in connection with the purchase of former Texas New Mexico (TNM) pipeline assets from Link Energy LLC (Link) in 2004, we identified a number of environmental liabilities for which we received a purchase price reduction from Link and recorded a total environmental reserve of $20 million, of which we agreed in an arrangement with TNM to bear the first $11 million in costs of pre-May 1999 environmental issues. TNM also agreed to pay all costs in excess of $20 million (excluding certain deductibles). TNM s obligations are guaranteed by Shell Oil Products (SOP). As of December 31, 2011, we had incurred approximately $22 million of remediation costs associated with these sites, while SOP s share has been approximately $11 million.

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 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.

Air Emissions

Our U.S. operations are subject to the U.S. Clean Air Act (Clean Air Act), comparable state laws and associated state and federal regulations. Our Canadian operations are subject to federal and provincial air emission regulations. In 2010, the Canadian Council of Ministers of the Environment agreed to move forward to finalize a new air quality management system. The new Canadian standards for air quality and industrial air emissions are currently in development, with implementation expected to begin in 2013. Under these laws, permits may be required before construction can commence on a new or modified source of potentially significant air emissions, and operating permits may be required for sources already constructed. We may be required to incur certain capital and operating expenditures in the next several years to install air pollution control equipment and otherwise comply with more stringent state and regional air emissions control when we attempt to obtain or maintain permits and approvals for sources of air emissions. Although we believe that our operations are in substantial compliance with these laws in the 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.

Climate Change Initiatives

Canada

In response to recent studies suggesting that emissions of carbon dioxide, methane and certain other gases may be contributing to warming of the Earth s atmosphere, many nations, including Canada, have agreed to limit emissions of these gases, generally referred to as greenhouse gases (GHG), pursuant to the 1997 United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol. The Kyoto Protocol required Canada to reduce its emissions of GHG to 6% below 1990 levels by 2012. However, by 2009, emissions in Canada were 17% higher than 1990 levels. In December 2011, Canada withdrew from the Kyoto Protocol, but signed the Durban Platform committing it to a legally binding treaty to reduce GHG emissions, the terms of which are to be defined by 2015 and are to become effective in 2020. Environment Canada continues to promote the domestic GHG initiatives implemented while Canada was signatory to the Kyoto Protocol.

In 2007, in response to the Kyoto Protocol, the Canadian federal government introduced the *Regulatory Framework for Air Emissions* (also known as the Turning the Corner measures) a regulatory framework for regulating industrial GHG emissions by establishing mandatory emissions reduction requirements on a sector basis. Originally, this framework was intended to be implemented by 2010; however no federally mandated reduction targets for GHGs have been implemented to date. Since 2004, companies emitting more than 100 thousand tons per year (kt/y) of CO_2 equivalent (CO_2e) were required to report their GHG emissions under the Greenhouse Gas Emissions Reporting Program. In 2010, this reporting threshold was reduced to 50 kt/y. The current operations of PMC fall well below this 50 kt/y threshold.

In Alberta, the provincial government implemented the *Specified Gas Emitters Regulation* in 2007 (under the Alberta Environmental and Protection and Enhancement Act), which mandated a 12% reduction in emission intensity over 2003-2005 levels for all facilities emitting more than 100 kt/y of CO_2e. It is anticipated that the threshold for this regulation will be reduced in future years. Alberta also has a GHG reporting threshold at 50 kt/y of CO_2e. Again, emissions from PMC s facilities are well below the 50 kt/y threshold.

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In April 2010, Environment Canada proposed the *Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations* under the Canadian Environmental Protection Act (CEPA). Transportation is one of the largest sources of GHG emissions in Canada, accounting for about 27% of total GHG emissions in 2007. Passenger cars and light trucks account for approximately 12% of total GHG emissions or 45% of transportation emissions. The objective of the proposed regulations is to reduce GHG emissions by establishing mandatory GHG emission standards for new vehicles of the 2011 and later model years that are aligned with U.S. standards. The alignment of vehicle emission standards across North America will provide a level playing field for North American automobile manufacturers. The governments of Canada and the U.S. are consulting to develop aligned regulations to reduce emissions from heavy-duty trucks. In December 2010, the Canadian federal government finalized the *Renewable Fuel Regulations* under CEPA. These regulations require an annual average renewable content of five percent in gasoline and will require a two percent renewable content in diesel fuel and heating oil by 2011. These requirements are further intended to reduce GHG emissions in the transportation sector. No other regulatory initiatives to reduce GHG emissions in the truck transportation sector have been announced.

In August 2011, Environment Canada released the text of the proposed regulations to reduce emissions from the coal-fired electricity sector. The proposed regulations apply a stringent performance standard to coal-fired electricity generated units. The standard will be based on parity with the emissions performance of high-efficiency natural gas generation. This is expected to promote replacement of coal-fired units that are reaching the end of their economic life, and will encourage investment in cleaner generation technologies, such as high-efficiency natural gas generation and renewable energy, as well as the use of carbon capture and storage. Regulations are scheduled to come into effect in July 2015, and are likely to stimulate increased demand for natural gas. No other regulatory initiatives to reduce GHG emissions in the electricity sector have been announced.

With regard to the oil and gas industry and the pipeline transportation sector, it is unclear at this time what direction the government plans to take. However, given that there have been no specific regulatory changes announced to date regarding GHG emissions reduction in these sectors; any future initiatives would likely not take effect until beyond 2015.

United States

The United States is not participating in the Kyoto Protocol, and there has not been significant activity with respect to reducing GHG emissions at the federal level in recent years.

In 2009, the U.S. EPA adopted rules for establishing a GHG emissions reporting program. Fewer than ten of our facilities are presently subject to the federal GHG reporting requirements. These include facilities with combustion GHG emissions and potential fugitive emissions above the reporting thresholds. We import sufficient quantities of finished fuel products into the U.S. to be required to report that activity as well. We also continue to monitor GHG emissions for all of our facilities and activities. At the present time, we do not anticipate the need to purchase GHG credits or install control technology to reduce GHG emissions at any of our facilities.

In 2010, the EPA promulgated regulations establishing Title V and Prevention of Significant Deterioration permitting requirements for large sources of GHG s. Fewer than ten of our existing facilities are potential major sources of GHG subject to these permitting requirements. In the absence of any control requirements for GHG s for our facilities that would need to be incorporated into existing Title V permits, we believe the impact of these permitting requirements on our facilities will be minimal.

In the absence of federal climate legislation in the U.S., a number of regional efforts have emerged aimed at reducing GHG emissions. Two of the more significant non-federal GHG programs are the Regional Greenhouse Gas Initiative (RGGI) and the Western Climate Initiative (WCI). RGGI, which includes a number of states in the northeastern U.S., implemented a cap-and-trade program in 2009. At present, this program only applies to utility power plants. None of our facilities are affected by RGGI.

The WCI includes several western U.S. states, some of which are full (voting) members and some of which are just observers. Of the states involved, only California has implemented a GHG cap-and-trade program, authorized under Assembly Bill 32 (AB32). The California Air Resources Board has published a list of facilities expected to be subject to this program. At this time, the list only includes one of our facilities, the Lone Star Gas Liquids facility in Shafter, California. The rules implementing the AB32 program were finalized in December 2011, and we are still evaluating the impact of this program on our Shafter facility. The compliance objectives of the GHG cap-and-trade program will not kick in until 2013 at the earliest and we do not anticipate any problems in complying with those obligations going forward.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our services, results of operations, and cash flows. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in

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the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events, that could have an adverse effect on our assets and operations.

The operations of our refinery customers could also be negatively impacted by current GHG legislation or new regulations resulting in increased operating or compliance costs. Some of the proposed federal and state cap and trade legislation would require businesses that emit GHG s to buy emission credits from government, other businesses, or through an auction process. In addition, refiners could be required to purchase emission credits for GHG emissions resulting from their own refining operations as well as the fuels they sell. While it is not possible at this time to predict the final form of cap-and-trade legislation, any new federal or state restrictions on GHG emissions could result in material increased compliance costs, additional operating restrictions and an increase in the cost of feedstock and products produced by our refinery customers.

Water

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act (CWA), 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 Pipeline Safety/Pipeline and Storage Tank Integrity Management above and Note 11 to our Consolidated Financial Statements. Federal, state and provincial regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with discharge permits or other requirements of the CWA.

The Oil Pollution Act of 1990 (OPA) amended certain provisions of the CWA, as they relate to the release of petroleum products into navigable waters. 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. We believe that we are in substantial compliance with applicable OPA requirements. State and Canadian federal and provincial laws also impose requirements relating to the prevention of oil releases and the remediation of areas affected by releases when they occur. We believe that we are in substantial compliance with all such federal, state and Canadian requirements.

Other Regulation

Transportation Regulation

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

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

State Regulation. Our intrastate pipeline transportation activities are subject to various state laws and regulations, as well as orders of state regulatory bodies, including the Railroad Commission of Texas (TRRC) and the California Public Utility Commission (CPUC). The CPUC prohibits certain of our subsidiaries from acting as guarantors of our senior notes and credit facilities.

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

Regulation of OCS Pipelines. The Outer Continental Shelf Lands Act requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. In June 2008, the Minerals Management Service (now replaced by the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE)) issued a final rule establishing formal and informal complaint procedures for shippers that believe they have been denied open and nondiscriminatory access to transportation on the OCS. We do not expect the rule to have a material impact on our operations or results.

Energy Policy Act of 1992 and Subsequent Developments. In October 1992, Congress passed the Energy Policy Act of 1992 (EPAct), which, among other things, required the FERC to issue rules to establish 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 establishing a formulaic methodology for petroleum pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index. The FERC reviews the formula every five years. Effective July 1, 2011, the current index for the five year period ending July 2016 is the producer price index for finished goods plus an adjustment factor of 2.65 percent. The previous methodology, which was in place until June 30, 2011, was based on the producer price index for finished goods plus an adjustment factor of 1.3 percent. Pipelines are allowed to raise their rates to the rate ceiling level generated by application of the index. If the methodology reduces the ceiling level such that it is lower than a pipeline s filed rate, the pipeline must reduce its rate to conform with the lower ceiling unless doing so would reduce a rate grandfathered by EPAct (see below) to below the grandfathered level. A pipeline must, as a general rule, use 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 that may be used in certain specified circumstances. Because the indexing methodology for the next five-year period is tied to an inflation index and is not based on pipeline-specific costs, the indexing methodology could hamper our ability to recover cost increases.

Under the EPAct, petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of EPAct are deemed to be just and reasonable under the ICA, if such rates had not been subject to complaint, protest or investigation during that 365-day period. 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.

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. The majority of our transportation segment profit in the U.S. is produced by rates that are either grandfathered or set by agreement with one or more shippers. In Canada, rates are set to cover operating costs and a return on capital, without specific agreements with shippers. Shippers may make application to federal or provincial regulatory agencies if they disagree with rates that have been set.

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: (i) driver operations, (ii) log book maintenance, (iii) truck manifest preparations, (iv) safety placard placement on the trucks and trailer vehicles, (v) drug and alcohol testing, (vi) operation and equipment safety and (vii) many other aspects of truck operations. We are also subject to OSHA with respect to our trucking operations.

Our trucking assets in Canada are subject to regulation by both federal and provincial transportation agencies in the provinces in which they are operated. These regulatory agencies do not set freight rates, but do establish and administer rules and regulations relating to other matters including equipment, facility inspection, reporting and safety. We are licensed to operate both intra and inter provincially under the direction of the National Safety Code (NSC) that is administered by Transport Canada. Our for hire service is primarily the transportation of crude oil, condensates and NGLs. We are required under the NCS among other things to monitor: (i) driver operations, (ii) log book maintenance, (iii) truck manifest preparations, (iv) safety placard placement on the trucks and trailers, (v) operation and equipment safety and (vi) many other aspects of trucking operations. We are also subject to Occupational Health and Safety regulations with respect to our trucking operations.

Cross Border Regulation

As a result of our cross border activities, including importation of crude oil, LPG and natural gas between the United States and Canada, we are subject to a variety of legal requirements pertaining to such activities including export/import license requirements, tariffs, Canadian and U.S. customs and taxes and requirements relating to toxic substances. U.S. legal requirements relating to these activities include regulations adopted pursuant to the Short Supply Controls of the Export Administration Act, the North American Free Trade Agreement and the Toxic Substances Control Act. Violations of these licensing, 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.

Market Anti-Manipulation Regulation

In November 2009, the Federal Trade Commission (FTC) issued regulations pursuant to the Energy Independence and Security Act of 2007, intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to $1 million per violation per day. In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the Commodity Futures Trading Commission (CFTC) to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to crude oil swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to crude oil purchases and sales. In November 2010, the CFTC issued proposed rules to implement their new anti-manipulation authority. The proposed rules would subject violators to a civil penalty of up to the greater of $1 million or triple the monetary gain to the person for each violation.

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We have not experienced a material impact from the FTC regulations. The CFTC rules are not final. We will continue to monitor the status of proposed rules.

Natural Gas Storage Regulation

PNG is subject to extensive laws and regulations. Our natural gas storage operations are subject to regulatory oversight by numerous federal, state, and local regulatory agencies, many of which are authorized by statute to issue, and have issued, rules and regulations binding on the natural gas storage and pipeline industry, related businesses and market participants. The failure to comply with such laws and regulations can result in substantial penalties and fines. The regulatory burden increases our cost of doing business and, consequently, affects our profitability. Our historical and projected operating costs reflect the recurring costs resulting from compliance with these regulations, and we do not anticipate material expenditures in excess of these amounts in the absence of future acquisitions or changes in regulation, or discovery of existing but unknown compliance issues. We do not believe that we are affected by applicable laws and regulations in a significantly different manner than are our competitors.

The following is a summary of the kinds of regulation that may impact our natural gas storage operations. However, our unitholders should not rely on such discussion as an exhaustive review of all regulatory considerations affecting our natural gas storage operations.

Our natural gas storage facilities provide natural gas storage services in interstate commerce and are subject to comprehensive regulation by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act of 1938 (NGA). Pursuant to the NGA and FERC regulations, storage providers are prohibited from making or granting any undue preference or advantage to any person or subjecting any person to any undue prejudice or disadvantage or from maintaining any unreasonable difference in rates, charges, service, facilities, or in any other respect. The terms and conditions for services provided by our facilities are set forth in FERC approved tariffs. We have been granted market-based rate authorization for the services that our facilities provide. Market-based rate authority allows us to negotiate rates with individual customers based on market demand.

The FERC also has authority over the siting, construction, and operation of U.S. pipeline transportation and storage facilities and related facilities used in the transportation, storage and sale for resale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. The FERC s authority extends to maintenance of accounts and records, terms and conditions of service, acquisition and disposition of facilities, initiation and discontinuation of services, imposition of creditworthiness and credit support requirements applicable to customers and relationships among pipelines and storage companies and certain affiliates. Our natural gas storage entities are required by the FERC to post certain information daily regarding customer activity, capacity and volumes on their respective websites. Additionally, the FERC has jurisdiction to impose rules and regulations applicable to all natural gas market participants including PNG Marketing and PAA Natural Gas Canada to ensure market transparency. FERC regulations require that buyers and sellers of more than a de minimis volume of natural gas report annual numbers and volumes of relevant transactions to the FERC. Our natural gas storage facilities and related marketing entities are subject to these annual reporting requirements.

Under the Energy Policy Act of 2005 (EPAct 2005) and related regulations, it is unlawful in connection with the purchase or sale of natural gas or transportation services subject to FERC jurisdiction to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 gives the FERC civil penalty authority to impose penalties for certain violations of up to $1,000,000 per day for each violation. FERC also has the authority to order disgorgement of profits from transactions deemed to violate the NGA and the EPAct 2005.

Bluewater provides storage service by means of receipts or deliveries of natural gas at the international border with Canada or within the Province of Ontario. The importation and exportation of natural gas from and to the U.S. and Canada is subject to regulation by U.S. Customs and Border Protection, U.S. Department of Energy and the NEB. Bluewater, PNG Marketing and PAA Natural Gas Canada have regulatory authorization to import and export natural gas from and to the U.S. and Canada.

The natural gas industry historically has been heavily regulated. New rules, orders, regulations or laws may be passed or implemented that impose additional costs, burdens or restrictions on us. We cannot give any assurance regarding the likelihood of such future rules, orders, regulations or laws or the effect they could have on our business, financial condition, and results of operations or ability to make distributions to our unitholders.

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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 the time 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 2,400% 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. As a result, we have elected to self-insure more activities against certain of these operating hazards and expect this trend will continue in the future. Due to the events of September 11, 2001, insurers have excluded acts of terrorism and sabotage from our insurance policies. We have elected to purchase a separate insurance policy for acts of terrorism and sabotage.

Since the terrorist attacks, the United States Government has issued numerous warnings that energy assets, including our nation s pipeline infrastructure, may be future targets of terrorist organizations. These developments expose our operations and assets to increased risks. We have instituted security measures and procedures in conformity with DOT guidance. We will institute, as appropriate, additional security measures or procedures indicated by the DOT or the Transportation Safety Administration. However, we cannot assure you that these or any other security measures would protect our facilities from an 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

Our real property holdings are generally comprised of: (i) parcels of land that we own in fee, (ii) surface leases, underground storage leases and (iii) easements, rights-of-way, permits, crossing agreements or licenses from landowners or governmental authorities permitting the use of certain lands for our operations. We believe we have satisfactory title or the right to use the sites upon which our significant facilities are located, subject to customary liens, restrictions or encumbrances. We have no knowledge of any challenge to the underlying fee title of any material fee, lease, easement, right-of-way, permit or license held by us or to our rights pursuant to any material deed, lease, easement, right-of-way, permit or license, and we believe that we have satisfactory rights pursuant to all of our material leases, easements, rights-of-way, permits and licenses. Some of our real property rights (mainly for pipelines) may be subject to termination under agreements that provide for one or more of: periodic payments, term periods, renewal rights, revocation by the licensor or grantor and possible relocation obligations. We believe that our real property holdings are adequate for the conduct of our business activities and that none of the burdens discussed above will materially (i) detract from the value of such properties or (ii) interfere with the use of such properties in our business.

Employees and Labor Relations

To carry out our operations, our general partner or its affiliates (including Plains Midstream Canada) employed approximately 3,800 employees at December 31, 2011. None of the employees of our general partner are subject to a collective bargaining agreement, except for nine employees covered by an agreement scheduled for renegotiation in September 2012 and another eight employees covered by another agreement scheduled for renegotiation in September 2013. Our general partner considers its employee relations to be good.

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Summary of Tax Considerations

The following is a brief summary of material tax considerations of owning and disposing of common units, however, the tax consequences of ownership of common units depends in part on the owner s individual tax circumstances. It is the responsibility of each unitholder, either individually or through a tax advisor, to investigate the legal and tax consequences, under the laws of pertinent U.S. federal, 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.

Partnership Status; Cash Distributions

We are treated for federal income tax purposes as a partnership based upon our meeting the Qualifying Income Exception imposed by Section 7704 of the Internal Revenue Code (the Code), which we must meet each year. The owners of our common units are considered partners in the Partnership so long as they do not loan their common units to others to cover short sales or otherwise dispose of those units. Accordingly, we are not liable for U.S. federal income taxes, and a common unitholder is required to report on the unitholder s federal income tax return the unitholder s share of our income, gains, losses and deductions. In general, cash distributions to a common unitholder are taxable only if, and to the extent that, they exceed the tax basis in the common units held. In certain cases, we are subject to, or have paid Canadian income and withholding taxes. Canadian withholding taxes are due on intercompany interest payments and dividend payments and are treated as income tax expenses as a result of our restructuring of how we hold our Canadian investment on January 1, 2011. Unitholders may be eligible for foreign tax credits with respect to allocable Canadian witholding and income taxes paid.

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

Basis of Common Units

A unitholder s initial tax basis for a common unit is generally the amount paid for the common unit and the unitholder s share of our nonrecourse liabilities (or liabilities for which no partner bears the economic risk of loss). A unitholder s basis is generally increased by the unitholder s share of our income and by any increases in the unitholder s share of our nonrecourse liabilities. That basis will be decreased, but not below zero, by the unitholder s share of our losses and distributions (including deemed distributions due to a decrease in the unitholder s share of our nonrecourse liabilities).

Limitations on Deductibility of Partnership Losses

The deduction by a unitholder of that unitholder s allocable share of our losses will be limited to the amount of that unitholder s tax basis in his or her common units and, in the case of an individual unitholder or a corporate unitholder who is subject to the at risk rules (generally, certain closely-held corporations), to the amount for which the unitholder is considered to be at risk with respect to our activities, if that is less than the unitholder s tax basis. A unitholder must recapture losses deducted in previous years to the extent that distributions cause the unitholder s at risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable as a deduction to the extent that his at-risk amount is subsequently increased, provided such losses do not exceed such unitholder s tax basis in his common units. Upon the taxable disposition of a common unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but may not be offset by losses suspended by the basis limitation. Any loss previously suspended by the at risk limitation in excess of that gain could no longer be used.

In addition to the basis and at-risk limitation described above, in the case of taxpayers subject to the passive loss rules (generally, individuals and certain closely held corporations), any partnership losses generated by us 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 or suspended 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.

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Section 754 Election

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

Disposition of Common Units

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

Non-U.S., State, Local and Other Tax Considerations

In addition to federal income taxes, unitholders will likely be subject to other taxes, such as non-U.S., state and local income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which a unitholder resides or in which we conduct business or own property. We own property and conduct business in most states in the United States as well as several provinces in Canada. A unitholder may also be required to file state income tax returns and to pay taxes in various states. As a result of recent organizational restructuring of our Canadian entities as of January 1, 2011, our Canadian-source income will pass through a taxable entity and thus will not be subject to Canadian filing obligations for our unitholders. For 2010 and prior years, a unitholder is required to file Canadian federal income tax returns and to pay Canadian federal and provincial income taxes in respect of our Canadian source income earned by partnership entities that were pass-through entities for tax purposes. Unitholders who are not resident in the United States may have additional tax reporting and payment requirements.

A unitholder may be subject to interest and penalties for failure to comply with such requirements. In certain states, tax losses may not produce a tax benefit in the year incurred (if, for example, we have no income from sources within that state) and also may not be available to offset income in subsequent taxable years. Some states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be more or less than a particular unitholder s income tax liability owed to a particular state, may not relieve the unitholder from the obligation to file an income tax return in that state. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

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

An investment in common units by tax-exempt organizations (including Individual Retirement Accounts (IRAs) and other retirement plans) and non-U.S. 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, non-U.S. corporation or other non-U.S. 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 non-U.S. unitholders are subject to federal income tax withholding at the highest applicable rate.

Available Information

We make available, free of charge on our Internet website at 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 (SEC).

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Item 1A. ***Risk Factors***

Risks Related to Our Business

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

We have a number of organic growth projects that require the expenditure of significant amounts of capital. Many of these projects involve numerous regulatory, environmental, commercial, weather-related, political and legal uncertainties that will be beyond our control. As these projects are undertaken, required approvals may not be obtained, may be delayed or may be obtained with conditions that materially alter the expected return associated with the underlying projects. Moreover, revenues associated with these organic growth projects will not increase immediately upon the expenditures of funds with respect to a particular project and these projects may be completed behind schedule or in excess of budgeted cost. We may construct pipelines, facilities or other assets in anticipation of market demand that dissipates or market growth that never materializes. As a result of these uncertainties, the anticipated benefits associated with our capital projects may not be achieved.

Loss of our investment grade credit rating or the ability to receive open credit could negatively affect our ability to purchase crude oil and NGL supplies or to capitalize on market opportunities.

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 and NGL markets. Our ability to capture that benefit, however, is subject to numerous risks and uncertainties; including our maintaining an attractive credit rating and continuing to receive open credit from our suppliers and trade counterparties. For example, our ability to utilize our crude oil storage capacity for merchant activities to capture contango market opportunities is dependent upon having adequate credit facilities, including the total amount of credit facilities and the cost of such credit facilities, which enables us to finance the storage of the crude oil from the time we complete the purchase of the oil until the time we complete the sale of the oil. In addition, our ability to capture potential margin attributable to seasonal and other market variations in supply and demand for NGL is also in part dependent upon our ability to use our NGL storage facilities for merchant activities.

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

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

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

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

Generally, it is our policy that we establish a margin for crude oil or other products we purchase by selling such products for physical delivery to third party users, or by entering into a future delivery obligation under derivative contracts. 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 not to acquire and hold physical inventory or derivative products for the purpose of speculating on commodity price changes. These policies and practices cannot, however, eliminate all risks. For example, any event that disrupts our anticipated physical supply of crude oil or other products could expose us to risk of loss resulting from price changes. We are also exposed to basis risk when crude oil or other products are purchased against one pricing index and sold against a different index. Moreover, we are exposed to some risks that are not hedged, including risks on certain of our inventory, such as linefill, which must be maintained in order to transport crude oil on our pipelines. In an effort to maintain a balanced position, specifically authorized personnel can purchase or sell an aggregate limit of up to 800,000 barrels of crude oil, refined products and NGL. Although this activity is monitored independently by our risk management function, it exposes us to risks within predefined limits and authorizations.

In addition, our operations involve the risk of non-compliance with our risk policies. We have taken steps within our organization to implement our processes and procedures designed to detect unauthorized trading. We cannot assure you, however, that these steps will detect and prevent all violations of our risk policies and procedures, particularly if deception or other intentional misconduct is involved.

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

Results from our supply and logistics segment are influenced by the overall forward market for crude oil. A contango market (meaning that the price of crude oil for future deliveries is higher than current prices) is favorable to commercial strategies that are associated with storage capacity as it allows a party to simultaneously purchase production or bulk arrangements at current prices for storage and sell at higher prices for future delivery. Wide contango spreads combined with price structure volatility generally have a favorable impact on our results. A backwardated market (meaning that the price of crude oil for future deliveries is lower than current prices) has a positive impact on lease gathering margins because crude oil gatherers can capture a premium for prompt deliveries; however, in this environment there is little incentive to store crude oil as current prices are above future delivery prices. In either case, margins can be improved when prices are volatile. The periods between these two market structures are referred to as transition periods. If the market is in a backwardated to transitional structure, our results from our supply and logistics segment may be less than those generated during the more favorable contango market conditions. Additionally, a prolonged transition period or a lack of volatility in the pricing structure may further negatively impact our results. Depending on the overall duration of these transition periods, how we have allocated our assets to particular strategies and the time length of our crude oil purchase and sale contracts and storage lease agreements, these transition periods may have either an adverse or beneficial effect on our aggregate segment profit. A prolonged transition from a backwardated market to a contango market, or vice versa (essentially a market that is neither in pronounced backwardation nor contango), represents the least beneficial environment for our supply and logistics segment.

The nature of our business and assets exposes us to significant compliance costs and liabilities. As we add assets, we historically have experienced a corresponding increase in the absolute number of releases of crude oil into the environment. Although we believe we have reduced the trend, additional assets acquired in the future could again result in increased frequency of releases. Substantial expenditures may be required to maintain the integrity of our pipelines and terminals at acceptable levels.

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

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

We currently devote substantial resources to comply with DOT-mandated pipeline integrity rules. The 2006 Pipeline Safety Act requires the DOT to issue regulations for certain pipelines that were not previously subject to regulation. The DOT regulations include requirements for the establishment of pipeline integrity management programs. We have also developed and implemented certain integrity measures that go beyond regulatory mandate. A portion of these measures are now incorporated into the 2010 Consent Decrees. See Items 1 and 2. Business and Properties Regulation.

The acquisitions we have completed over the last several years have included pipeline assets with varying ages and maintenance and operational histories. Accordingly, for 2012 and beyond, we will continue to focus on pipeline integrity management as a primary operational emphasis. In that regard, we have implemented programs intended to maintain the integrity of our assets, with a focus on risk reduction through testing, enhanced corrosion control, leak detection, and damage prevention. We have an internal review process pursuant to which we examine various aspects of our pipeline and gathering systems that are not subject to the DOT

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pipeline integrity management mandate. The purpose of this process is to review the surrounding environment, condition and operating history of these pipeline and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, in addition to potential cost increases related to unanticipated regulatory changes or injunctive remedies resulting from EPA enforcement actions, we may elect (as a result of our own internal initiatives) to spend substantial sums to ensure the integrity of and upgrade our pipeline systems to maintain environmental compliance and, in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines. We cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures. See Item 3. Legal Proceedings Environmental.

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

A portion of our transportation segment profit is derived from pipeline transportation tariff associated with the Santa Ynez and Point Arguello fields located offshore California and the onshore fields in the San Joaquin Valley. We expect that there will continue to be natural production declines from each of these fields as the underlying reservoirs are depleted. In addition, any significant production disruption from OCS fields and the San Joaquin Valley due to production problems, transportation problems, earthquakes or other reasons could have a material adverse effect on our business. We estimate that a 5,000 barrel per day decline in volumes shipped from these OCS fields would result in a decrease in annual transportation segment profit of approximately $10 million. A similar decline in volumes shipped from the San Joaquin Valley would result in an estimated $3 million incremental decrease in annual transportation segment profit.

In addition, the explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico, as well as the resulting oil spill, may lead to increased governmental regulation of our industry s operations in a number of areas, including health and safety, environmental, and licensing, any of which could restrict the supply of crude oil available for transportation. For example, new legislation has been proposed which would revamp federal oversight of offshore drilling, set new safety standards for drilling equipment and well design, and increase liability limits for offshore drilling companies, among other provisions. Other governmental responses may include deep-water drilling moratoria or other potentially major restrictions on drilling and production. Although we currently have no assets that would directly be affected by such regulation, we cannot predict with any certainty whether such regulation, if enacted, might indirectly affect our business.

Our profitability depends on the volume of crude oil, refined product and NGL shipped, processed, purchased, stored, fractionated and/or gathered.

Our profitability could be materially impacted by a decline in the volume of crude oil, natural gas and NGL transported, gathered, stored or processed at our facilities. A material decrease in crude oil or natural gas production or crude oil refining, as a result of depressed commodity prices, natural decline rates attributable to oil and natural reservoirs, a decrease in exploration and development activities or otherwise, could result in a decline in the volume of crude oil, natural gas or NGL handled by our facilities and other energy logistics assets.

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

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

Fluctuations in demand can negatively affect our operating results.

Demand for crude oil is dependent upon a variety of factors, including price, 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 impact demand. Demand also depends on the ability and willingness of shippers having access to our transportation assets to satisfy their demand by deliveries through those assets.

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

Fluctuations in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example, reduced petrochemical demand observed due to lower activity in the automobile and construction industries), increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL products, particularly propane, or other reasons, could result in a decline in the volume of NGL products we handle or a reduction of the fees we charge for our services. Also, increased supply of NGL products could reduce the value of NGLs we handle and reduce the margins realized. Our NGL products and their demand are affected as follows:

Ethane. Ethane is typically supplied as purity ethane and as part of an ethane-propane mix. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Although ethane is typically extracted as part of the mixed NGL stream at gas processing plants, if natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls, it may be more profitable for natural gas processors to leave the ethane in the natural gas stream thereby reducing the volume of NGLs delivered for fractionation and marketing.

Propane. Propane is used as a petrochemical feedstock in the production of ethylene and propylene, as a heating, engine and industrial fuel, and in agricultural applications such as crop drying. Changes in demand for ethylene and propylene could also adversely affect demand for propane. The demand for propane as a heating fuel is significantly affected by weather conditions. The volume of propane sold is at its highest during the six-month peak heating season of October through March. Demand for our propane may be reduced during periods of warmer-than-normal weather.

Normal Butane. Normal butane is used in the production of isobutane, as a refined product blending component, as a fuel gas, either alone or in a mixture with propane, and in the production of ethylene and propylene. Changes in the composition of refined products resulting from governmental regulation, changes in feedstocks, products and economics, demand for heating fuel and for ethylene and propylene could adversely affect demand for normal butane.

Iso-butane. Iso-butane is predominantly used in refineries to produce alkylates to enhance octane levels. Accordingly, any action that reduces demand for motor gasoline or demand for isobutane to produce alkylates for octane enhancement might reduce demand for isobutane.

Natural Gasoline. Natural gasoline is used as a blending component for certain refined products and as a feedstock used in the production of ethylene and propylene. Changes in the mandated composition of motor gasoline resulting from governmental regulation and in demand for ethylene and propylene could adversely affect demand for natural gasoline.

NGLs and products produced from NGLs also compete with products from global markets. Any reduced demand or increased supply for ethane, propane, normal butane, iso-butane or natural gasoline in the markets we access for any of the reasons stated above could adversely affect demand for the services we provide as well as NGL prices, which could negatively impact our operating results.

If we do not make acquisitions or if we make acquisitions that fail to perform as anticipated, our future growth may be limited.

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

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

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

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

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

Any acquisition involves potential risks, including:

- performance from the acquired businesses or assets 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.

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We may not be able to successfully close our pending acquisition of the BP NGL Assets, and even if we are successful, such assets may not perform as anticipated.

As noted above, we have signed a definitive purchase and sale agreement to purchase the BP NGL Assets. The closing of the acquisition of such assets is subject to a variety of conditions, including the receipt of various regulatory approvals. We can give no assurance that all such closing conditions will be satisfied and that we will ultimately be able to successfully close the acquisition of the BP NGL Assets.

In addition, even if we are successful in our efforts to close the acquisition of the BP NGL Assets, there are a variety of factors that may cause such assets to underperform relative to our expectations.

For example, BP has historically operated the BP NGL Assets as an integrated, proprietary business which primarily purchases mixed NGL products and/or NGL processing rights (i.e., extraction rights) in Alberta and then transports, processes, fractionates, stores and sells the purity products in Alberta, Sarnia, Ontario and the upper-Midwest of the U.S. Since a significant portion of the BP NGL Assets is dependent upon Western Canadian wet gas supply, throughput on the BP NGL Assets may continue to be adversely impacted by continued declines in Western Canadian wet gas production, particularly declines in wet gas moving East through the Empress processing facilities where there is excess gas processing capacity and significant competition for gas processing extraction rights.

In addition, the BP NGL Assets are comprised of significant fractionation, storage, and marketing assets in the Sarnia area, which is expected to be a primary market for NGL produced from the Marcellus and Bakken plays, and potentially the Utica Shale area. The assets and markets in and around the Sarnia area may be negatively impacted in the short run by the expected increases in NGL production from the Marcellus and the Bakken due to an increase in NGL products in the area. Over the intermediate and long-term we expect supply volume growth from these resources plays will increase the utilization of the BP NGL Assets in the area; however, we can provide no assurance that will occur.

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Also, BP s historical practices involved limited hedging of the commodity risk inherent in its NGL processing operations which leaves the financial results of the BP NGL Assets exposed to changes in NGL prices. As a result, when and if the acquisition of BP s NGL Assets closes, we will acquire inventories of NGL that are not hedged and are exposed to NGL pricing variations, which we may not be able to hedge at profitable levels. Over time, however, once our risk management controls and procedures are applied to the BP NGL Assets, we intend to reduce this type of exposure through increased hedging and contracting activity.

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

Our U.S. interstate common carrier liquids pipelines, which include both crude oil and refined products pipelines, are subject to regulation by the FERC under the ICA. The ICA requires that tariff rates for liquids 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.

For our U.S. interstate common carrier liquids pipelines subject to FERC regulation under the ICA, shippers may protest our pipeline tariff filings, file complaints against our existing rates, or the FERC can investigate on its own initiative. Under certain circumstances, the FERC could limit our ability to set rates based on our costs, or could order us to reduce our rates and could require the payment of reparations to complaining shippers for up to two years prior to the complaint. Natural gas storage facilities are subject to regulation by the FERC and certain state agencies.

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

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

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

Our sales of oil, natural gas, NGLs and other energy commodities, and related transportation and hedging activities, expose us to potential regulatory risks.

The Federal Trade Commission, the FERC and the Commodity Futures Trading Commission hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil, natural gas, NGLs or other energy commodities, and any related transportation and/or hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Additionally, to the extent that we enter into transportation contracts with natural gas pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such capacity. Any failure on our part to comply with the FERC s regulations and policies, or with an interstate pipeline s tariff, could result in the imposition of civil and criminal penalties. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Legislation and regulatory initiatives relating to hydraulic fracturing could reduce domestic production of crude oil and natural gas.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. Recent advances in hydraulic fracturing techniques have resulted in significant increases in crude oil and natural gas production in many basins in the United States and Canada. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production, and it is typically regulated by state and provincial oil and gas commissions. The process has recently become subject to increased scrutiny due to public concerns that it could result in contamination of drinking water supplies, and there have been a variety of legislative and regulatory proposals to prohibit, restrict, or more closely regulate various forms of hydraulic fracturing. Any legislation or regulatory initiatives that curtail hydraulic fracturing could reduce the production of crude oil and natural gas in the United States or Canada, and could thereby reduce demand for our transportation, terminalling and storage services.

We face competition in our transportation, facilities and supply and logistics activities.

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

With respect to our natural gas storage operations, the principal elements of competition are rates, terms of service, supply and market access and flexibility of service. An increase in competition in our markets could arise from new ventures or expanded operations from existing competitors. Our natural gas storage facilities compete with several other storage providers, including regional storage facilities and utilities. Certain major pipeline companies and independent storage providers have existing storage facilities connected to their systems that compete with some of our facilities.

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With regard to our NGL operations, we compete with large oil, natural gas and natural gas liquids companies that may have greater financial resources and access to supplies of natural gas and NGLs than we do. Some of the competitors may expand or construct gathering, processing and transportation systems that would create additional competition for the services that we provide to our customers. The principal elements of competition are rates, processing fees (e.g., extraction premiums) paid to the owners or aggregators of natural gas to be processed, geographic proximity to the natural gas or NGL mix, available processing and fractionation capacity, transportation alternatives and their associated costs, and access to end user markets.

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

Over the last several years, as the scale and scope of our business activities has expanded, the breadth and depth of available insurance markets has contracted. 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.

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

As of December 31, 2011, our consolidated debt outstanding was approximately $5.2 billion, consisting of approximately $4.5 billion principal amount of long-term debt (including senior notes) and approximately $0.7 billion of short-term borrowings. As of December 31, 2011, we had over $3.6 billion of available borrowing capacity under our senior unsecured revolving credit facilities, our senior secured hedged inventory facility and PNG s credit agreement.

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

- a significant portion of our cash flow will be dedicated to the payment of principal and interest on our indebtedness and may not be available for other purposes, including the payment of distributions on our units and capital expenditures;

- credit rating agencies may view our debt level negatively;

- covenants contained in our existing debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;

- our ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership purposes may be limited;

- we may be at a competitive disadvantage relative to similar companies that have less debt; and

- we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level.

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

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

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

As of December 31, 2011, we had approximately $5.2 billion of consolidated debt, of which approximately $4.7 billion was at fixed interest rates and approximately $0.5 billion was at variable interest rates (including $150 million of interest rate derivatives that swap fixed-rate debt for floating). We are exposed to market risk due to the floating interest rates on our credit facilities. Our results of operations, cash flows and financial position could be adversely affected by significant increases in interest rates above current levels. Additionally, increases in interest rates could adversely affect our supply and logistics segment results by increasing interest costs associated with the storage of hedged crude oil and LPG inventory. Further, the trading price of our common units may be sensitive to changes in interest rates and any rise in interest rates could adversely impact such trading price.

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

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

An impairment of goodwill could reduce our earnings.

At December 31, 2011, we had approximately $1.9 billion of goodwill. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the acquired tangible and separately measurable intangible net assets. U.S. generally accepted accounting

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principles, or GAAP, requires us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. If we were to determine that any of our goodwill was impaired, we would be required to take an immediate charge to earnings with a corresponding reduction of partners equity and increase in balance sheet leverage as measured by debt to total capitalization.

A decision to not develop our Pier 400 project could reduce our earnings.

At December 31, 2011, we had $95 million of capitalized project costs on our balance sheet for the Pier 400 project. Development of the project is still subject to the completion and execution of a land lease with the Port of Los Angeles, receipt of certain other regulatory approvals, as well as completion of commercial contracts with potential customers. If we determine that the project will not be developed, we would be required to take a charge to earnings.

Our natural gas storage facilities may not be able to deliver as anticipated, which could prevent us from meeting our contractual obligations and cause us to incur significant costs.

Although we believe that our operating gas storage facilities have been designed to meet our contractual obligations with respect to wheeling, injection, withdrawal and gas specifications, if our facilities do not perform as designed and we fail to wheel, inject or withdraw natural gas at contracted rates, or cannot deliver natural gas consistent with contractual quality specifications, we could incur significant costs to satisfy our contractual obligations.

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

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

Maritime claimants could arrest the vessels carrying our cargos.

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

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

We are dependent on use of third-party assets for certain of our operations.

Certain of our business activities require the use of third-party assets over which we may have little or no control. For example, a portion of our storage and distribution business conducted in the Los Angeles basin (acquired in connection with the Pacific merger) receives waterborne crude oil through dock facilities operated by a third party in the Port of Long Beach. If at any time our access to this dock was denied, and if access to an alternative dock could not be arranged, the volume of crude oil that we presently receive from our customers in the Los Angeles basin may be reduced, which could result in a reduction of facilities segment revenue and cash flow.

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

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

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

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

Prior to making any distribution on our common units, we will reimburse our general partner and its affiliates, including officers and directors of the general partner, for all expenses incurred on our behalf (other than expenses related to the Class B units of Plains AAP, L.P.). The reimbursement of expenses and the payment of fees could adversely affect our ability to make distributions.

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The general partner has sole discretion to determine the amount of these expenses. In addition, our general partner and its affiliates may provide us services for which we will be charged reasonable fees as determined by the general partner.

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

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

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

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

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

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

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

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

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

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

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

- an existing unitholder s proportionate ownership interest in the Partnership will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- 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 and/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. Our partnership agreement allows the general partner to incur obligations on our behalf that are expressly non-recourse to the general partner. The general partner has entered into such limited recourse obligations in most instances involving payment liability and intends to do so in the future.

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:

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

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

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

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

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

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

In addition, a change of control would constitute an event of default under our revolving credit agreements. During the continuance of an event of default under our revolving credit agreements, the administrative agent may terminate any outstanding commitments of the lenders to extend credit to us under our revolving credit facility and/or declare all amounts payable by us under our revolving credit facility immediately due and payable. A change of control also may trigger payment obligations under various compensation arrangements with our officers.

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Risks Related to an Investment in Our Debt Securities

The right to receive payments on our outstanding debt securities 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.

Our debt securities are effectively subordinated to claims of our and our subsidiaries secured creditors. In the event of insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up, secured creditors would generally have the right to be paid in full before any distribution is made to the holders of our 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, 2011, our total outstanding debt was approximately $5.2 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 energy 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.

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.

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. Under our credit facilities, we may be required to establish cash reserves for the future payment of principal and interest on outstanding amounts. If we are unable to obtain the funds necessary to pay the principal amount at maturity of our debt securities, or to repurchase our 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 our debt securities. We cannot assure you that we would be able to refinance our debt securities.

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

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

- to provide for the proper conduct of our business and the businesses of our operating partnerships (including reserves for future capital expenditures and for our anticipated future credit needs);

- to provide funds for distributions to our unitholders and the general partner for any one or more of the next four calendar quarters; or

- to comply with applicable law or any of our loan or other agreements.

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

Tax Risks to Common Unitholders

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

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. A publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless it satisfies a qualifying income requirement. Based on our current operations we believe that we are treated as a partnership rather than a corporation for such purposes; however, a change in our business could cause us to be treated as a corporation 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 tax matter affecting us.

In addition, a change in current law may cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to additional entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Specifically, beginning in 2008, we became subject to a new entity level tax on the portion of our income that is generated in Texas in the prior year. Imposition of any such additional taxes on us will reduce the cash available for distribution to our unitholders. If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distributions or to pay our debt obligations would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in cash flow and after-tax returns to our unitholders, likely causing a substantial reduction in the value of our common units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal income tax purposes, our target distribution amounts will be adjusted to reflect the impact of that law on us.

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

We will be considered to have been technically terminated for tax purposes if there are sales or exchanges which, in the aggregate, constitute 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of measuring whether the 50% threshold is reached, multiple sales of the same interest are counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in our filing two tax returns for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but it would result in our being treated as a new partnership for tax purposes. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we were unable to determine that a termination occurred. The IRS has recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

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

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

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

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

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

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

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

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

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

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

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

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if our unitholders do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property and conduct business in most states in the United States, most of which impose a personal income tax on individuals and an income tax on corporations and other entities. It is our unitholders responsibility to file all U.S. federal, state, local and non-U.S. tax returns. As a result of the Canadian restructuring, 2010 is the last year that non-Canadian resident unitholders will be required to file Canadian tax returns with respect to an investment in our units.

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

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

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

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

A unitholder who loans his common units to a short seller to cover a short sale of common units (i) may be considered as having disposed of the loaned units, (ii) may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and (iii) may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

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

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

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

We prorate our items of income, gain, loss and deduction between existing unitholders and unitholders who purchase our units based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. Recently, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

Item 1B. ***Unresolved Staff Comments***

None.

Item 3. ***Legal Proceedings***

General. In the ordinary course of business, we are involved in various legal proceedings. To the extent we are able to assess the likelihood of a negative outcome for these proceedings, our assessments of such likelihood range from remote to probable. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue the estimated amount. We do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows. Although we believe that our operations are presently in material compliance with applicable requirements, as we acquire and incorporate additional assets it is possible that EPA or other governmental entities may seek to impose fines, penalties or performance obligations on us (or on a portion of our operations) as a result of any past noncompliance whether such noncompliance initially developed before or after our acquisition.

New Jersey Department of Environmental Protection v. ExxonMobil Corp. et al. In June 2007, the NJDEP brought suit in the Superior Court of New Jersey against GATX, ExxonMobil and our subsidiary, Plains Products Terminals (PPT), to recover natural resources damages associated with, and to require remediation of, contamination at our Paulsboro terminal facility. ExxonMobil and GATX filed third-party demands against

PPT, seeking indemnity and contribution. The natural resources damages were settled with the State of New Jersey. The settlement agreement was approved by the court in September 2011. PPT s allocated share of this liability is $550,000, which was paid in November 2011. We remain in dispute with ExxonMobil regarding future remediation responsibility as well as allocation of prior remediation costs.

Bay Area Air Quality Management District (BAAQMD). During the time period from 2008 to the present, we have received from BAAQMD various notices of violation for alleged violations of California air emissions regulations at our Martinez terminal. In December 2011, we entered into a settlement agreement with BAAQMD, pursuant to which we paid $116,000 in penalties.

Pemex Exploración y Producción v. Big Star Gathering Ltd L.L.P. et al. In a case filed in the Texas Southern District Court, Pemex Exploración y Producción (PEP) alleges that certain parties stole condensate from pipelines and gathering stations and conspired with U.S. companies (primarily in Texas) to import and market the stolen condensate. PEP does not allege that Plains was part of any conspiracy, but that it dealt in the condensate only after it had been obtained by others and resold to Plains Marketing, L.P. PEP seeks actual damages, attorney s fees, and statutory penalties from Plains Marketing, L.P. At a hearing held on October 20, 2011, the Court ruled that Texas law (not Mexican law) governs the actions.

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Environmental

General

Although we believe that our efforts to enhance our leak prevention and detection capabilities have produced positive results, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline and storage operations. As we expand our pipeline assets through acquisitions, we typically improve on (reduce) the releases from such assets (in terms of frequency or volume) as we implement our integrity management procedures, remove selected assets from service and invest capital to upgrade the assets. However, the inclusion of additional miles of pipe in our operations may result in an increase in the absolute number of releases company-wide compared to prior periods. These releases can result from unpredictable man-made or natural forces and may reach navigable waters or other sensitive environments. Whether current or past, damages and liabilities associated with any such releases from our assets may substantially affect our business.

At December 31, 2011, our estimated undiscounted reserve for environmental liabilities, including the reserve related to our Rainbow Pipeline release as discussed further below, totaled approximately $74 million, of which approximately $12 million was classified as short-term and $62 million was classified as long-term. At December 31, 2010, our estimated undiscounted reserve for environmental liabilities totaled approximately $66 million, of which approximately $10 million was classified as short-term and $56 million was classified as long-term. At December 31, 2011 and December 31, 2010, we had recorded receivables totaling approximately $47 million and $5 million, respectively, for amounts probable of recovery under insurance and from third parties under indemnification agreements.

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

Rainbow Pipeline Release

On April 29, 2011, we experienced a crude oil release on a remote section of our Rainbow Pipeline located in Alberta, Canada. Upon detection of the release, approximately 45 miles of the pipeline were isolated and depressurized and emergency response personnel were mobilized to conduct clean-up operations in cooperation with the Alberta ERCB. After completing the pipeline repair and responding to additional regulatory requested pipeline inspections and information requests, we received regulatory approval and restarted full operation of the pipeline on August 30, 2011. We completed the remaining site clean-up, reclamation and remediation activities in December 2011, and have demobilized all equipment and personnel from the site. Post-reclamation environmental monitoring will continue in accordance with regulatory requirements.

The aggregate total estimated cost to clean-up and remediate the site, before insurance recoveries, was approximately $70 million, which was accrued to field operating costs on our consolidated statement of operations. While we believe this amount to be final, there is a small amount of work that will require completion during the spring of 2012 with regard to monitoring and land contouring. The costs associated with this work are not expected to be material.

As of December 31, 2011, we have a remaining undiscounted gross environmental remediation liability for the release of approximately $2 million. This liability is presented as a current liability within the caption Accounts payable and accrued liabilities on our consolidated balance sheet. We maintain insurance coverage, which is subject to certain exclusions and deductibles, to protect us against such environmental liabilities. As of December 31, 2011, we have a remaining receivable of approximately $41 million for the portion of this liability that we believe is probable of recovery from insurance, net of deductibles. This receivable has been recognized as a current asset within the caption Trade accounts receivable and other receivables, net on our consolidated balance sheet with the offset reducing operating expense on our consolidated statement of operations.

Insurance

A pipeline, terminal or other facility may experience damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and certain assets. The insurance policies are subject to deductibles or self-insured retentions that we consider reasonable. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues.

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The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, we may not be able to maintain adequate insurance in the future at rates we consider reasonable. As a result, we may elect to self-insure or utilize higher deductibles in certain insurance programs. For example, the market for hurricane-or windstorm-related property damage coverage has remained difficult the last few years. The amount of coverage available has been limited, and costs have increased substantially with the combination of premiums and deductibles for the 2010 renewal totaling 20% or more of the coverage limit.

For the two years prior to June 2011, we have purchased a hurricane limit of $10 million to cover property and business interruption, representing substantially the level of insurance that was available. The coverage provided by these policies contained much stricter limitations than the insurance policies available prior to hurricanes Rita and Katrina. As a result of these conditions, we did not renew this coverage in June 2011 and do not plan to purchase this coverage for 2012. We will, instead, self-insure this risk. This decision does not affect our third-party liability insurance, which still covers hurricane-related liability claims and which we have renewed at our historic levels. In addition, although we believe that we have established adequate reserves to the extent such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

Item 4. ***Mine Safety Disclosures***

Not applicable.

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PART II

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

Our common units are listed and traded on the New York Stock Exchange (NYSE) under the symbol PAA. As of February 22, 2012, the closing market price for our common units was $81.51 per unit and there were approximately 159,000 record holders and beneficial owners (held in street name). As of February 22, 2012, there were 155,568,749 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)
2011					
4th Quarter	$	73.55	$	54.90	$ 1.0250
3rd Quarter	$	64.98	$	56.41	$ 0.9950
2nd Quarter	$	65.69	$	57.80	$ 0.9825
1st Quarter	$	65.96	$	60.21	$ 0.9700
2010					
4th Quarter	$	65.20	$	60.91	$ 0.9575
3rd Quarter	$	64.21	$	57.33	$ 0.9500
2nd Quarter	$	60.06	$	44.12	$ 0.9425
1st Quarter	$	57.11	$	49.82	$ 0.9350

(1) Cash distributions for a quarter are declared and paid in the following calendar quarter. See the Cash Distribution Policy below for a discussion of our policy regarding distribution payments.

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

Cash Distribution Policy

In accordance with our partnership agreement, we will distribute all of our available cash to our unitholders within 45 days following the end of each quarter in the manner described below. Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the end of that quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the general partner to:

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

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

In order to enhance our distribution coverage ratio and liquidity following a significant acquisition, our general partner may agree to reduce the amounts due to it as incentive distributions. Upon closing the acquisitions of Pacific Energy Partners LP (Pacific) in November 2006, Rainbow Pipe Line Company, Ltd. (Rainbow) in May 2008 and PAA Natural Gas Storage, LLC (PNGS) in September 2009, our general partner agreed to reduce the amounts due to it as incentive distributions. The total reduction in incentive distributions related to the Pacific, Rainbow and PNGS acquisitions was $83 million as displayed on an annual basis in the following table (in millions):

Acquisition	**2007**	**2008**	**2009**	**2010**	**2011**	**Total**
Pacific	$ 20	$ 15	$ 15	$ 10	$ 5	$ 65
Rainbow		3	6	1		10
PNGS			1	5	2	8
Total	$ 20	$ 18	$ 22	$ 16	$ 7	$ 83

The final $1 million of incentive distribution reductions related to these acquisitions was applied to the November 2011 distribution.

On December 1, 2011, we entered into a definitive agreement to acquire all of the outstanding shares of BP Canada Energy Company, a wholly owned subsidiary of BP Corporation North America Inc. (the BP NGL acquisition). We expect this acquisition will close in the second quarter of 2012, subject to Canadian and U.S. regulatory approvals and customary closing conditions. Upon closing this acquisition, our general partner has agreed to reduce the amount of its incentive distributions by $15 million per year for two years, beginning with the first distribution paid following closing. Thereafter, our general partner has agreed to an ongoing reduction of $10 million per year. See Note 3 to our Consolidated Financial Statements for further discussion of the BP NGL acquisition.

We paid $204 million to the general partner in incentive distributions in 2011. Additionally, on February 14, 2012, we paid a quarterly distribution of $1.025 per unit applicable to the fourth quarter of 2011, of which approximately $63 million was paid to the general partner in incentive distributions. See Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner.

Under the terms of the agreements governing our debt, we are prohibited from declaring or paying any distribution to unitholders if a default or event of default (as defined in such agreements) exists. No such default has occurred. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Facilities and Indentures.

See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters for information regarding securities authorized for issuance under equity compensation plans.

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Issuer Purchases of Equity Securities

We did not repurchase any of our common units during the fourth quarter of 2011, and we do not have any announced or existing plans to repurchase any of our common units other than potential repurchases consistent with past practice in providing units for relatively small vestings of phantom units under our long-term incentive plans (LTIP).

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

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2011, 2010, 2009, 2008 and 2007 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,				
	2011	2010	2009	2008	2007
	(in millions, except for per unit data)				
Statement of operations data:					
Total revenues	$ 34,275	$ 25,893	$ 18,520	$ 30,061	$ 20,394
Net income	$ 994	$ 514	$ 580	$ 437	$ 365
Net income attributable to Plains	$ 966	$ 505	$ 579	$ 437	$ 365
Per unit data:					
Basic net income per limited partner unit	$ 4.91	$ 2.41	$ 3.34	$ 2.66	$ 2.47
Diluted net income per limited partner unit	$ 4.88	$ 2.40	$ 3.32	$ 2.64	$ 2.45
Declared distributions per limited partner unit (1)	$ 3.91	$ 3.76	$ 3.62	$ 3.50	$ 3.28
Balance sheet data (at end of period):					
Total assets	$ 15,381	$ 13,703	$ 12,358	$ 10,032	$ 9,906
Long-term debt	$ 4,520	$ 4,631	$ 4,142	$ 3,259	$ 2,624
Total debt	$ 5,199	$ 5,957	$ 5,216	$ 4,286	$ 3,584
Partners capital	$ 5,974	$ 4,573	$ 4,159	$ 3,552	$ 3,424
Other data:					
Net cash provided by operating activities	$ 2,365	$ 259	$ 365	$ 857	$ 796
Net cash used in investing activities	$ (2,020)	$ (851)	$ (686)	$ (1,339)	$ (663)
Net cash provided by/(used in) financing activities	$ (345)	$ 604	$ 338	$ 464	$ (124)
Capital expenditures:					
Acquisitions	$ 1,404	$ 407	$ 393	$ 735	$ 125
Internal growth projects	$ 531	$ 355	$ 364	$ 491	$ 525
Maintenance	$ 120	$ 93	$ 81	$ 81	$ 50
	$	$	$ 15	$ 37	$ 9

Investments in unconsolidated subsidiaries

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	Year Ended December 31,				
	2011	**2010**	**2009**	**2008**	**2007**
Volumes (2) (3)					
Transportation segment (average daily volumes in thousands of barrels per day):					
Tariff activities	2,942	2,889	2,836	2,851	2,712
Trucking	105	97	85	97	105
Transportation segment total	3,047	2,986	2,921	2,948	2,817
Facilities segment:					
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	70	61	56	53	46
Natural gas storage (average monthly capacity in billions of cubic feet)	71	47	26	14	13
LPG processing (average throughput in thousands of barrels per day)	14	14	15	17	18
Facilities segment total (average monthly capacity in millions of barrels)	82	70	61	56	48
Supply & Logistics segment (average daily volumes in thousands of barrels per day):					
Crude oil lease gathering purchases	742	620	612	658	685
LPG sales	103	96	105	103	90
Waterborne cargos	21	68	55	80	71
Supply & Logistics segment total	866	784	772	841	846

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

(2) Volumes associated with acquisitions represent total volumes for the number of days or months (dependent on the calculation) we actually owned the assets divided by the number of days or months in the year.

(3) Facilities total is calculated as the sum of: (i) crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products (LPG) storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude British thermal unit (Btu) equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) LPG processing volumes multiplied by the number of days in the year and divided by the number of months in the year.

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
- Company Overview
- Overview of Operating Results, Capital Investments and Significant Activities
- Acquisitions and Internal Growth Projects
- Critical Accounting Policies and Estimates

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- Recent Accounting Pronouncements
- Results of Operations
- Outlook
- Liquidity and Capital Resources

Executive Summary

Company Overview

We engage in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as the processing, transportation, fractionation, storage and marketing of natural gas liquids (NGL). The term NGL includes ethane and natural gasoline products as well as propane and butane, products which are also commonly referred to as liquid petroleum gas (LPG). The terms NGL and LPG are sometimes used interchangeably within this document depending on the context. Through our general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P., we also own and operate natural gas storage facilities. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries and are managed through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See Results of Operations Analysis of Operating Segments for further discussion.

Overview of Operating Results, Capital Investments and Significant Activities

During 2011, our net income attributable to Plains was $966 million, which was a $461 million year-over-year increase as compared to that recognized during 2010. This increase was primarily driven by strong industry fundamentals and contributions from our acquisitions and internal growth projects. The major items impacting comparability between periods were:

- the favorable results experienced within our supply and logistics segment, which were impacted by (i) the active development of crude oil and liquids-rich resource plays, (ii) favorable crude oil basis differentials and (iii) favorable market structure;

- the favorable results experienced within our transportation segment, which were impacted by (i) increased volumes in key production areas, (ii) increased tariff rates and (iii) favorable foreign currency exchange rates, partially offset by the unfavorable impact of a crude oil release on our Rainbow Pipeline; and

- the favorable results experienced within our facilities segment, which were impacted by expansions to our asset base through acquisitions and our ongoing internal growth projects.

Other key items impacting 2011 were:

- the completion of nine acquisitions for the aggregate consideration, net of cash acquired, of approximately $1.3 billion;

- the issuance of debt and equity for net proceeds of approximately $1.9 billion (this amount includes PNG s issuance, in conjunction with the Southern Pines Acquisition, of approximately 17.4 million common units to third parties for net proceeds of approximately $370 million);

- the increase in our income tax expense related to our Canadian operations as a result of Canadian tax legislation changes that became effective on January 1, 2011; and

- the redemption of our 7.75% senior notes that were maturing in 2012 for approximately $222 million, as well as the loss of $23 million recognized in Other income/(expense), net within our Consolidated Financial Statements in conjunction with the early redemption of these notes.

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Acquisitions and Internal Growth Projects

We completed a number of acquisitions and capital expansion projects in 2011, 2010 and 2009 that have impacted our results of operations. The following table summarizes our capital expenditures for acquisitions, internal growth projects, maintenance capital and investments in unconsolidated entities for the periods indicated (in millions):

	For the Year Ended December 31, 2011	2010	2009
Acquisition capital (1) (2)	$ 1,404	$ 407	$ 393
Internal growth projects	531	355	364
Maintenance capital	120	93	81
Investment in unconsolidated entities (1)			15
	$ 2,055	$ 855	$ 853

(1) Initial investments in unconsolidated entities are included within "Acquisition capital," whereas additional subsequent investments in unconsolidated entities are recognized within "Investment in unconsolidated entities."

(2) Acquisition capital for the year ended December 31, 2011 includes a cash deposit of $50 million (reflected in "Other current assets" on our Consolidated Balance Sheet) paid upon signing a definitive agreement related to the pending BP NGL acquisition, which is expected to close in the second quarter of 2012. See Note 3 to our Consolidated Financial Statements for further discussion of this pending acquisition.

Acquisitions

Acquisitions are financed using a combination of equity and debt, including borrowings under our credit facilities and the issuance of senior notes. Businesses acquired impact our results of operations commencing on the closing date of each acquisition. Our acquisition and capital expansion activities are discussed further in "Liquidity and Capital Resources" and in Note 3 to our Consolidated Financial Statements. Information regarding acquisitions completed in 2011, 2010 and 2009 is set forth in the table below (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Southern Pines	02/09/2011	$ 765	Facilities
Gardendale Gathering System	11/29/2011	349	Transportation
Western	12/29/2011	220	Facilities and Transportation
Other (1)	Various	70	Transportation, Facilities and Supply & Logistics
2011 Total		$ 1,404	
Nexen	12/30/2010	$ 229	Supply & Logistics and Transportation
Other	Various	178	Transportation and Facilities
2010 Total		$ 407	

PNGS	09/03/2009	$	215	Facilities
Other	Various		178	Transportation and Facilities
2009 Total		$	393	

(1) Includes a cash deposit of $50 million (reflected in Other current assets on our Consolidated Balance Sheet) paid upon signing a definitive agreement related to the pending BP NGL acquisition, which is expected to close in the second quarter of 2012. See Note 3 to our Consolidated Financial Statements for further discussion of this pending acquisition.

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Internal Growth Projects

Our 2011 projects included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2011, 2010 and 2009 projects (in millions):

Projects	**2011**	**2010**	**2009**
PAA Natural Gas Storage (multiple projects) (1) (2)	$ 89	$ 85	$ 26
Rainbow II Pipeline (1)	44	3	
Cushing - Phases VII and VIII	3	25	25
Cushing - Phases IX through XI	38	21	
Basile Gas Processing Facility	37	14	2
Ross Rail Project (1)	27		
Bumstead Facility	14	2	
Bone Spring Project (1)	15		
Patoka - Phases I through IV (1)	15	20	22
Eagle Ford Project (1)	18		
Edmonton Land		17	
West Texas Gathering Lines		15	
Pier 400 (1)	13	11	18
Nipisi Storage and Truck Terminal (1)	9	6	18
Kerrobert Pumping Project		1	33
Rangeland Tankage			36
St. James - Phases I through III		21	73
Other projects (3)	209	114	111
Total	$ 531	$ 355	$ 364

(1) These projects will continue into 2012. See Liquidity and Capital Resources Acquisitions, Capital Expenditures and Distributions Paid to Our Unitholders, General Partner and Noncontrolling Interests 2012 Capital Expansion Projects.

(2) Expenditures shown for 2009 for PNGS include only those expenditures made subsequent to the acquisition in September 2009 of the remaining 50% interest in PNGS.

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

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 (GAAP). These critical accounting policies are discussed in Note 2 to our Consolidated Financial Statements.

Critical Accounting Estimates

The preparation of financial statements in conformity with GAAP and rules and regulations of the United States Securities and Exchange Commission (SEC) 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. On a regular basis, we evaluate our assumptions, judgments and estimates. We also discuss our critical accounting policies and estimates with the Audit Committee of the Board of Directors.

We believe that the assumptions, judgments and estimates involved in the accounting for our (i) purchase and sales accruals, (ii) fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (iii) fair value of derivatives, (iv) accruals and contingent liabilities, including our equity compensation plan accruals, (v) property and equipment and depreciation expense and (vi) allowance for doubtful accounts have the greatest potential impact on our consolidated financial statements. These areas are key components of our results of operations and are based on complex rules which require us to make judgments and estimates, so we consider these to be our critical accounting policies. Such critical accounting estimates are discussed further as follows:

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. For the year ended December 31, 2011, we estimate that approximately 2% of both annual revenues and cost of sales were recorded using purchase and sales estimates. Accordingly, a 10% variance from this estimate would impact annual revenues, cost of sales, operating income and net income attributable to Plains line items by approximately 1% or less on an annual 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.

Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets. In accordance with Financial Accounting Standards Board (FASB) guidance regarding business combinations, with each acquisition, we allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. If the initial accounting for the business combination is incomplete when the combination occurs, an estimate will be recorded. Any subsequent adjustments to this estimate, if material, will be recognized retroactive to the date of acquisition. With exception to our equity method investments, we also expense the transaction costs as incurred in connection with each acquisition. In addition, we are required to recognize intangible assets separately from goodwill. Intangible assets with finite lives are amortized over their estimated useful life as determined by management. Goodwill and intangible assets with indefinite lives are not amortized but instead are periodically assessed for impairment.

Impairment testing entails estimating future net cash flows relating to the asset, based on management s estimate of future revenues, future cash flows and market conditions including pricing, demand, competition, operating costs and other factors. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, contracts and industry expertise, involves professional judgment and is ultimately based on acquisition models and management s assessment of the value of the assets acquired and, to the extent available, third party assessments. Uncertainties associated with these estimates include changes in production decline rates, production interruptions, fluctuations in refinery capacity or product slates, economic obsolescence factors in the area and potential future sources of cash flow. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. We perform our goodwill impairment test annually (as of June 30) and when events or changes in circumstances indicate that the carrying value may not be recoverable. We did not have any material goodwill impairments in 2011, 2010 or 2009. See Note 2 to our Consolidated Financial Statements for a further discussion of goodwill.

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Fair Value of Derivatives. Our derivatives are reported at fair value as either assets or liabilities with changes in fair value recognized in either earnings or accumulated other comprehensive income (AOCI). The fair value of a derivative at a particular period end does not reflect the end results of a particular transaction, and will most likely not reflect the realized 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. For our derivatives that are not exchange traded, the estimates we use are based on indicative broker quotations or an internal valuation model. Our valuation models utilize market observable inputs such as price, volatility, correlation 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 annual revenues are based on estimates derived from internal valuation models. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Accruals and Contingent Liabilities. We record accruals or liabilities including, but not limited to, environmental remediation and governmental penalties, asset retirement obligations, equity compensation plan accruals (as further discussed below) 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, and the possibility of existing legal claims giving rise to additional claims. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. A variance of 5% in our aggregate estimate for the accruals and contingent liabilities discussed above would have an impact on earnings of up to approximately $17 million. 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.

Equity Compensation Plan Accruals. We accrue compensation expense for outstanding equity compensation awards. Under GAAP, we are required to estimate the fair value of our outstanding equity awards and recognize that fair value as compensation expense over the service period. For equity awards that contain a performance condition, the fair value of the equity award is recognized as compensation expense only if the attainment of the performance condition is considered probable. Uncertainties involved in this estimate include the actual unit price at time of vesting, whether or not a performance condition will be attained and the continued employment of personnel with outstanding equity awards.

We recognized total compensation expense of approximately $110 million, $98 million and $68 million in 2011, 2010 and 2009, respectively, related to equity awards granted under our various equity compensation plans. We cannot provide assurance that the actual fair value of our equity compensation awards will not vary significantly from estimated amounts. See Note 10 to our Consolidated Financial Statements.

Property and Equipment and Depreciation Expense. We compute depreciation using the straight-line method based on estimated useful lives. These estimates are based on various factors including condition, 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. During 2010 and 2011, we conducted a review to assess the useful lives of our property and equipment. See Note 2 to our Consolidated Financial Statements.

We periodically evaluate property and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. For example, we are continuing to develop our Pier 400 project in California. Development of the project is still subject to the completion and execution of a land lease with the Port of Los Angeles, receipt of certain other regulatory approvals, as well as completion of commercial contracts with potential customers. We have capitalized $95 million of costs associated with this project and would assess the project for impairment if we determine that the project will not be developed. Any evaluation is highly dependent on the underlying assumptions of related cash flows. We consider the fair value estimate used to calculate impairment of property and equipment a critical accounting estimate. In determining the existence of an impairment of carrying value, we make a number of subjective assumptions as to:

- whether there is an event or circumstance that may be indicative of an impairment;

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

Impairments of approximately $5 million, $13 million and less than $1 million were recognized during 2011, 2010 and 2009, respectively, and were predominantly related to assets that were taken out of service. These assets did not support spending the capital necessary to continue service and, in most instances, we utilized other assets to handle these activities.

Allowance for Doubtful Accounts. We perform credit evaluations of our customers and grant credit based on past payment history, financial conditions and anticipated industry conditions. Customer payments are regularly monitored and a provision for doubtful accounts is established based on specific situations and overall industry conditions. Our history of bad debt losses has been minimal and generally limited to specific customer circumstances; however, credit risks can change suddenly and without notice. See Note 2 to our Consolidated Financial Statements for additional discussion.

Recent Accounting Pronouncements

See Note 2 to our Consolidated Financial Statements for information regarding the effect of recent accounting pronouncements on our financial statements.

Results of Operations

Analysis of Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates such segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 13 to our Consolidated Financial Statements for a definition of segment profit (including an explanation of why this is a performance measure) and a reconciliation of segment profit to net income attributable to Plains.

Our segment analysis involves an element of judgment relating to the allocations between segments. In connection with its operations, the supply and logistics segment secures transportation and facilities services from the Partnership s other two segments as well as third-party service providers under month-to-month and multi-year arrangements. Intersegment transportation service rates are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates. Facilities segment services are also obtained at rates generally consistent with rates charged to third parties for similar services; however, certain terminalling and storage rates are discounted to our supply and logistics segment to reflect the fact that these services may be canceled on short notice to enable the facilities segment to provide services to third parties. Intersegment activities are eliminated in consolidation and we believe that the estimates with respect to these rates are reasonable. Also, our segment operating and general and administrative expenses reflect direct costs attributable to each segment; however, we also allocate certain operating expense and general and administrative overhead expenses between segments based on management s assessment of the business activities for the period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period. We believe that the estimates with respect to these allocations are reasonable.

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures that are known as non-GAAP financial measures in its evaluation of past performance and prospects for the future. The primary measures used by management are adjusted earnings before interest, taxes, depreciation and amortization (adjusted EBITDA) and implied distributable cash flow (DCF).

Management believes that the presentation of such additional financial measures provides useful information to investors regarding our performance and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and

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planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) the mark-to-market of derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), (iii) items that are not indicative of our core operating results and business outlook and/or (iv) other items that we believe should be excluded in understanding our core operating performance. We have defined all such items hereinafter as Selected Items Impacting Comparability. These additional financial measures are reconciled from the most directly comparable measures as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our consolidated financial statements and footnotes.

The following table sets forth an overview of our consolidated financial results calculated in accordance with GAAP:

[redacted]

Transportation segment profit	$ 555	$ 516	$ 477	$ 39	8%	$ 39	8%
Facilities segment profit	358	270	208	88	33%	62	30%
Supply & Logistics segment profit	647	240	345	407	170%	(105)	(30)%
Total segment profit	1,560	1,026	1,030	534	52%	(4)	%
Depreciation and amortization	(249)	(256)	(236)	7	3%	(20)	(8)%
Interest expense	(253)	(248)	(224)	(5)	(2)%	(24)	(11)%
Other income/(expense), net	(19)	(9)	16	(10)	(111)%	(25)	(156)%
Income tax benefit/(expense)	(45)	1	(6)	(46)	(4,600)%	7	117%
Net income	994	514	580	480	93%	(66)	(11)%
Less: Net income attributable to noncontrolling interests	(28)	(9)	(1)	(19)	(211)%	(8)	(800)%
Net income attributable to Plains	$ 966	$ 505	$ 579	$ 461	91%	$ (74)	(13)%
Net income attributable to Plains:							
Earnings per basic limited partner unit	$ 4.91	$ 2.41	$ 3.34	$ 2.50	104%	$ (0.93)	(28)%
Earnings per diluted limited partner unit	$ 4.88	$ 2.40	$ 3.32	$ 2.48	103%	$ (0.92)	(28)%
Basic weighted average units outstanding	149	137	130	12	9%	7	5%
Diluted weighted average units outstanding	150	138	131	12	9%	7	5%

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The following table sets forth additional non-GAAP financial measures that are reconciled from the most directly comparable measures as reported in accordance with GAAP:

[redacted]							
Net income	$ 994	$ 514	$ 580	$ 480	93%	$ (66)	(11)%
Add:							
Depreciation and amortization	249	256	236	(7)	(3)%	20	8%
Income tax (benefit)/expense	45	(1)	6	46	4,600%	(7)	(117)%
Interest expense	253	248	224	5	2%	24	11%
EBITDA	$ 1,541	$ 1,017	$ 1,046	$ 524	52%	$ (29)	(3)%
Selected Items Impacting Comparability of EBITDA							
Equity compensation expense (1)	$ (77)	$ (67)	$ (50)	$ (10)	(15)%	$ (17)	(34)%
Gains/(losses) from other derivative activities (2)	62	(14)	34	76	543%	(48)	(141)%
Inventory valuation adjustments net of gains from related derivative activities (2)			24		%	(24)	(100)%
Net loss on early repayment of senior notes	(23)	(6)	(4)	(17)	(283)%	(2)	(50)%
Significant acquisition-related expenses	(10)			(10)	N/A		%
Net gain/(loss) on foreign currency revaluation (3)	(7)		12	(7)	N/A	(12)	(100)%
Other (4)	(2)	(2)	8		%	(10)	(125)%
Selected Items Impacting Comparability of EBITDA	$ (57)	$ (89)	$ 24	$ 32	36%	$ (113)	(471)%
EBITDA	$ 1,541	$ 1,017	$ 1,046	$ 524	52%	$ (29)	(3)%
Selected Items Impacting Comparability of EBITDA	57	89	(24)	(32)	(36)%	113	471%
Adjusted EBITDA	$ 1,598	$ 1,106	$ 1,022	$ 492	44%	$ 84	8%
Adjusted EBITDA	$ 1,598	$ 1,106	$ 1,022	$ 492	44%	$ 84	8%
Interest expense	(253)	(248)	(224)	(5)	(2)%	(24)	(11)%
Maintenance capital	(120)	(93)	(81)	(27)	(29)%	(12)	(15)%
Current income tax benefit/(expense)	(38)	1	(15)	(39)	(3,900)%	16	107%
Equity earnings in unconsolidated entities, net of distributions	10	6	(8)	4	67%	14	175%
Distributions to noncontrolling interests (5)	(47)	(15)	(2)	(32)	(213)%	(13)	(650)%
Other	(1)			(1)	N/A		%
Implied DCF	$ 1,149	$ 757	$ 692	$ 392	52%	$ 65	9%

(1) Our total equity compensation expense includes expense associated with awards that will or may be settled in units and awards that will or may be settled in cash. The awards that will or may be settled in units are included in our diluted earnings per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a selected item impacting comparability as the dilutive impact of the outstanding awards are included in our diluted earnings per unit calculation and the majority of the awards are expected to be settled in units. The compensation expense associated with these awards is shown as a selected item impacting comparability in the table above. The portion of compensation expense associated with awards that are certain to be settled in cash are not considered a selected item impacting comparability. See Note 10 to our Consolidated Financial Statements for a comprehensive discussion regarding our equity compensation plans.

(2) Includes mark-to-market gains and losses resulting from derivative instruments that are related to underlying activities in future periods or the reversal of mark-to-market gains and losses from the prior period. When applicable, inventory valuation adjustments are presented with related derivative activity. See Note 6 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and hedging activities.

(3) During 2011 and 2009, there were significant fluctuations in the value of the Canadian dollar (CAD) to the U.S. dollar (USD), resulting in gains and losses that were not related to our core operating results of the period and were thus classified as selected items impacting comparability. See Note 6 to our Consolidated Financial Statements for further discussion regarding our currency exchange rate risk hedging activities.

(4) Includes other immaterial selected items impacting comparability.

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(5) Includes distributions that pertain to the current quarter s net income and are to be paid in the subsequent quarter.

Transportation Segment

Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and refined products on pipelines, gathering systems, trucks and barges. The transportation segment generates revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees.

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

[redacted]							
Revenues (1)							
Tariff activities	$ 1,005	$ 937	$ 867	$ 68	7%	$ 70	8%
Trucking	160	108	94	52	48%	14	15%
Total transportation revenues	1,165	1,045	961	120	11%	84	9%
Cost and Expenses (1)							
Trucking costs	(115)	(73)	(63)	(42)	(58)%	(10)	(16)%
Field operating costs (excluding equity compensation expense)	(387)	(346)	(333)	(41)	(12)%	(13)	(4)%
Equity compensation expense - operations (2)	(14)	(12)	(9)	(2)	(17)%	(3)	(33)%
Segment general and administrative expenses (excluding equity compensation expense)	(69)	(65)	(61)	(4)	(6)%	(4)	(7)%
Equity compensation expense - general and administrative (2)	(38)	(36)	(25)	(2)	(6)%	(11)	(44)%
Equity earnings in unconsolidated entities	13	3	7	10	333%	(4)	(57)%
Segment profit	$ 555	$ 516	$ 477	$ 39	8%	$ 39	8%
Maintenance capital	$ 86	$ 67	$ 57	$ (19)	(28)%	$ (10)	(18)%
Segment profit per barrel	$ 0.50	$ 0.47	$ 0.45	$ 0.03	6%	$ 0.02	4%

				Favorable/(Unfavorable)			
Average Daily Volumes	**Year Ended December 31,**			**2011-2010**		**2010-2009**	
(in thousands of barrels per day) (3)	**2011**	**2010**	**2009**	**Volumes**	**%**	**Volumes**	**%**
Tariff activities							
All American	35	39	40	(4)	(10)%	(1)	(3)%
Basin	440	378	394	62	16%	(16)	(4)%
Capline	160	223	193	(63)	(28)%	30	16%
Line 63/Line 2000	114	109	131	5	5%	(22)	(17)%
Salt Lake City Area Systems	137	135	131	2	1%	4	3%
Permian Basin Area Systems	404	371	368	33	9%	3	1%

Mid-Continent Area Systems	213	214	209	(1)	%	5	2%
Manito	66	61	63	5	8%	(2)	(3)%
Rainbow	135	187	183	(52)	(28)%	4	2%
Rangeland	59	52	53	7	13%	(1)	(2)%
Refined products	102	116	100	(14)	(12)%	16	16%
Other	1,077	1,004	971	73	7%	33	3%
Tariff activities total	2,942	2,889	2,836	53	2%	53	2%
Trucking	105	97	85	8	8%	12	14%
Transporation segment total	3,047	2,986	2,921	61	2%	65	2%

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

(2) The equity compensation expense presented within the reconciliation to segment profit above includes the portion of the equity compensation expense represented by outstanding awards under the LTIP Plans that, pursuant to the terms of the award, will be settled in cash only and have no impact on diluted units. The equity compensation expense presented within the Selected Items Impacting Comparability section of the table as shown within the Results of Operations-Non-GAAP

Financial Measures discussion above excludes this portion of the equity compensation expense. See Note 10 to our Consolidated Financial Statements for additional discussion regarding our equity compensation plans.

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

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

The following is a discussion of items impacting transportation segment profit and segment profit per barrel for the periods indicated.

Operating Revenues and Volumes. As noted in the table above, our total transportation segment revenues, net of trucking costs, and volumes increased year-over-year for each comparative period presented. Noteworthy volume variances for 2011 compared to 2010 on our individual pipeline systems included (i) increased volumes on our Basin and Permian Basin Area Systems and certain of our Canadian pipelines driven by increased producer drilling in the surrounding regions and (ii) additional volumes of approximately 28,000 barrels per day for 2011 from the Robinson Lake pipeline acquired in connection with the Nexen acquisition in December 2010, which, in the Average Daily Volumes table above is included within Other. These favorable volume variances were partially offset by (i) decreased volumes on our Rainbow System related to downtime associated with a pipeline release detected during April 2011 (see further discussion below) as well as a third-party competitor pipeline placed into service during the third quarter of 2011 and (ii) decreased volumes on our Capline Pipeline System, primarily related to shifts in refinery supply and unplanned refinery downtime.

The most noteworthy favorable volume variance for 2010 compared to 2009 was the increase of volumes on our Capline pipeline system that resulted from the additional 21% undivided joint interest that we purchased in this pipeline system during December 2009.

In addition to the impact of the volumetric variances discussed above, our transportation segment results were also impacted by the following for the years ended December 31, 2011, 2010 and 2009:

• Rate Changes Revenues on our pipelines are impacted by various rate changes that may occur during the period. These rate changes primarily include the upward or downward indexing of rates on our FERC regulated pipelines, rate increases or decreases on our intrastate pipelines or other negotiated rate changes. During the comparable periods discussed herein, revenues fluctuated on our FERC regulated pipelines due to the upward indexing that was effective July 1, 2009 and July 1, 2011 and the downward indexing of the FERC rate that was effective as of July 1, 2010. Revenues were further impacted by increasing tariff rates on our Canadian pipelines.

• Foreign Exchange Impact Revenues and expenses from our Canadian based subsidiaries, which use the Canadian dollar as their functional currency, are translated at the prevailing average exchange rates for each month. The average CAD to USD exchange rates for 2011, 2010, and 2009 were $0.99 CAD: $1.00 USD, $1.03 CAD: $1.00 USD, and $1.14 CAD: $1.00 USD, respectively. Therefore, revenues from our Canadian pipeline systems and trucking operations were favorably impacted by approximately $12 million for 2011 compared to 2010 and by approximately $24 million for 2010 compared to 2009 due to the appreciation of the Canadian dollar relative to the U.S. dollar.

- Loss Allowance Revenue As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative-related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. The loss allowance revenue increased by approximately $16 million for 2011 compared to 2010 and $9 million for 2010 compared to 2009. These increases were primarily due to a higher average realized price per barrel during each of the comparative periods (including the impact of gains from derivative activities). The increase for the 2011 period was partially offset by lower volumes.

- Trucking Business Activity Trucking revenues, net of costs, increased by approximately $10 million for 2011 compared to 2010 primarily due to increased volumes in Canada resulting from increased producer drilling and downtime on the Rainbow Pipeline. See additional discussion regarding our Rainbow Pipeline release below as well as Note 11 to our Consolidated Financial Statements. Trucking revenues, net of costs, increased by approximately $4 million for 2010 compared to 2009 primarily due to volume increases from increased short-haul shipments and the addition of a heavy oil truck terminal at Nipisi, Alberta during December 2009, which was partially offset by higher fuel costs.

• Rainbow Pipeline System As a result of a crude oil release that occurred in April 2011, volumes and revenues for the Rainbow Pipeline System were reduced due to pipeline downtime on a portion of the system, and expenses increased due to repair and response costs. In an unrelated development occurring shortly after the release, we experienced additional downtime and expenses related to forest fires in the same region. As a result of these incidents, for the year ended December 31, 2011, we estimate revenues were reduced by approximately $21 million. However, such unfavorable impacts were partially offset by the benefit of increased tariff rates on the system, as discussed further above. We resumed service on the impacted segment of the pipeline on August 30, 2011. See Note 11 to our Consolidated Financial Statements for further information regarding this pipeline release.

• Acquisitions As discussed above, we acquired the Robinson Lake pipeline as part of the December 2010 Nexen acquisition. This pipeline contributed approximately $8 million of revenue for the year ended December 31, 2011.

Field Operating Costs. Field operating costs (excluding equity compensation expense as discussed further below) increased during the year ended December 31, 2011 compared to the year ended December 31, 2010 primarily due to the impact of approximately $11 million of environmental remediation expenses associated with the Rainbow Pipeline release. See Note 11 to our Consolidated Financial Statements for further information regarding this release. Excluding costs associated with this incident, field operating costs per barrel increased approximately 6% in 2011 to $0.34 per barrel as compared to $0.32 per barrel in 2010 due to general cost increases and volume mix. Field operating costs for 2009 were approximately $0.32 per barrel.

Equity Compensation Expenses. Equity compensation expense increased during 2011 and 2010, primarily due to (i) an increase in unit price of $10.66 and $9.94 during 2011 and 2010, respectively, and (ii) additional awards that have been deemed probable of occurring. The increase in unit price impacts the fair value of our liability-classified awards. A majority of our equity compensation awards (including the Class B units) contain performance conditions contingent upon achieving certain distribution levels. For awards with performance conditions (such as distribution targets), expense is accrued over the service period only if the performance condition is considered to be probable of occurring. When awards with performance conditions that were previously considered improbable become probable, we incur additional expense in the period that our probability assessment changes. This is necessary to bring the accrued liability associated with these awards up to the level it would have been if we had been accruing for these awards since the grant date. At December 31, 2011 and 2010, we determined that PAA distribution levels of $4.35 and $4.00 per unit, respectively, that were previously improbable, were probable of occurring. We incurred additional expense in both periods as a result of the additional awards that were deemed probable of occurring. See Note 10 to our Consolidated Financial Statements for further information regarding our equity compensation plans.

Maintenance Capital. Maintenance capital consists of capital investments for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production and/or functionality of our existing assets. The increase in maintenance capital in 2011 compared to 2010 and in 2010 compared to 2009 is primarily due to increased spending on pipeline integrity projects as well as timing of repairs between years.

Equity Earnings in Unconsolidated Entities. Equity earnings in unconsolidated entities increased for year ended December 31, 2011 compared to the year ended December 31, 2010 primarily due to earnings from our 34% interest in White Cliffs Pipeline LLC, which we acquired in September 2010.

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Facilities Segment

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

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

Storage and terminalling revenues (1)	$ 605	$ 490	$ 362	$ 115	23%	$ 128	35%
Natural gas sales (2)	191			191	N/A		N/A
Storage related costs (natural gas related)	(22)	(23)	(5)	1	4%	(18)	(360)%
Natural gas costs (2)	(183)			(183)	N/A		N/A
Field operating costs (excluding equity compensation expense)	(165)	(140)	(120)	(25)	(18)%	(20)	(17)%
Equity compensation expense - operations (3)	(2)	(2)	(1)		%	(1)	(100)%
Segment general and administrative expenses (excluding equity compensation expense)	(47)	(39)	(26)	(8)	(21)%	(13)	(50)%
Equity compensation expense - general and administrative (3)	(19)	(16)	(10)	(3)	(19)%	(6)	(60)%
Equity earnings in unconsolidated entities			8		%	(8)	(100)%
Segment profit	$ 358	$ 270	$ 208	$ 88	33%	$ 62	30%
Maintenance capital	$ 22	$ 17	$ 16	$ (5)	(29)%	$ (1)	(6)%
Segment profit per barrel	$ 0.36	$ 0.32	$ 0.29	$ 0.04	13%	$ 0.03	10%

Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	70	61	56	9	15%	5	9%
Natural gas storage (average monthly capacity in billions of cubic feet)	71	47	26	24	51%	21	81%
LPG processing (average throughput in thousands of barrels per day)	14	14	15		%	(1)	(7)%
Facilities segment total (average monthly capacity in millions of barrels)	82	70	61	12	17%	9	15%

(1) Includes intersegment amounts.

(2) Natural gas sales and costs are attributable to the activities performed by PNG s commercial optimization group, which was established in 2010.

(3) The equity compensation expense presented in the reconciliation to segment profit above includes the portion of the equity compensation expense represented by outstanding awards under the LTIPs that, pursuant to the terms of the award, will be settled in cash only and have no impact on diluted units. The equity compensation expense presented in the Selected Items Impacting Comparability section of the table as shown in the Results of Operations-Non-GAAP Financial Measures discussion above excludes this portion of the equity compensation expense. See Note 10 to our Consolidated Financial Statements for additional discussion regarding our equity compensation plans.

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

(5) Facilities total calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas capacity divided by 6 to account for the 6:1 mcf of gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) LPG processing volumes multiplied by the number of days in the year and divided by the number of months in the year.

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The following is a discussion of items impacting facilities segment profit and segment profit per barrel for the periods indicated.

Operating Revenues and Volumes. As noted in the table above, our facilities segment revenues, less storage related costs and natural gas purchases, and volumes increased year-over-year for each comparative year presented. The significant variances in revenues and average monthly volumes between the comparative periods are primarily due to our ongoing acquisition and expansion activities as discussed below:

- PNG Acquisition and Expansion Projects Revenues and volumes for 2011 compared to 2010 were favorably impacted by PNG s completion of the Southern Pines Acquisition, which closed on February 9, 2011. This acquisition contributed approximately $37 million of additional revenues, net of storage related costs, for 2011. Additionally, revenues and volumes for 2011 were further favorably impacted by the expansion of PNG s working gas capacity at the Pine Prairie facility.

Revenues and volumes for 2010 compared to 2009 were impacted by the PNGS Acquisition, which closed during the third quarter of 2009. This acquisition and ongoing expansion activities at PNG contributed approximately $58 million of additional net revenue and approximately 22 billion cubic feet (Bcf) of additional natural gas storage capacity for the year ended December 31, 2010. This net revenue amount includes the applicable storage related costs that are primarily due to increased volume of leased assets. Revenues were also favorably impacted by the acquisition of a natural gas processing business, which closed during the second quarter of 2009. This acquisition contributed approximately $9 million in additional revenue for the year ended December 31, 2010.

- Other Major Expansion Projects Expansion projects that were completed in phases throughout recent years also favorably impacted revenues and volumes. These expansion projects were completed at some of our major terminal locations, and we estimate that such projects increased our revenues by approximately $28 million on a combined basis for the year ended December 31, 2011 compared to the year ended December 31, 2010 and by a combined $14 million for the year ended December 31, 2010 compared to the year ended December 31, 2009. Additions and expansions at our Cushing, Patoka and Wichita Falls facilities comprised the majority of the 9 million barrel increase in total crude oil, refined products and LPG storage average monthly capacity in 2011 as compared to 2010, while additions and expansions at our Cushing, Patoka and St. James facilities accounted for the majority of the 5 million barrel increase in 2010 as compared to 2009.

- Other Revenues for all comparative periods also increased as a result of general escalations on existing leases.

Field Operating Costs and General and Administrative Expenses. Field operating costs and general and administrative expenses (excluding equity compensation expenses) in general remained relatively constant on a per barrel basis during the comparative periods presented. The absolute increase in costs during each comparable period is consistent with the overall growth of the segment through (i) expansion projects at some of our major terminal and storage locations and (ii) acquisitions such as the Southern Pines, PNGS and natural gas processing business acquisitions discussed above.

Equity Earnings in Unconsolidated Entities. In the September 2009 PNGS Acquisition, we acquired the remaining 50% of PAA/Vulcan. As a result, we no longer have interests in unconsolidated entities associated with our facilities segment. See Note 3 to our Consolidated Financial Statements for additional discussion regarding this acquisition.

Maintenance Capital. The increase in maintenance capital in 2011 compared to 2010 is primarily due to increased integrity spending and is impacted by timing between years for various equipment replacements and repairs.

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Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, refined products and LPG volumes. These revenues also include the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. 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 (i) increases or decreases in our supply and logistics segment volumes (which consist of lease gathered crude oil purchase volumes, LPG sales volumes and waterborne cargos), (ii) demand for lease gathering services we provide producers and (iii) the overall volatility and strength or weakness of market conditions and the allocation of our assets among our various risk management strategies. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. Although we believe that the combination of our lease gathered business and our risk management activities provides a balance that provides general stability in our margins, these margins are not fixed and will vary from period to period.

The following table sets forth our operating results from our supply and logistics segment for the periods indicated:

[redacted]							
Revenues	$ 33,068	$ 24,990	$ 17,759	$ 8,078	32%	$ 7,231	41%
Purchases and related costs (2)	(31,984)	(24,448)	(17,141)	(7,536)	(31)%	(7,307)	(43)%
Field operating costs (excluding equity compensation expense)	(314)	(195)	(183)	(119)	(61)%	(12)	(7)%
Equity compensation expense - operations (3)	(2)	(3)	(1)	1	33%	(2)	(200)%
Segment general and administrative expenses (excluding equity compensation expense)	(86)	(75)	(67)	(11)	(15)%	(8)	(12)%
Equity compensation expense - general and administrative (3)	(35)	(29)	(22)	(6)	(21)%	(7)	(32)%
Segment profit	$ 647	$ 240	$ 345	$ 407	170%	$ (105)	(30)%
Maintenance capital	$ 12	$ 9	$ 8	$ (3)	(33)%	$ (1)	(13)%
Segment profit per barrel	$ 2.05	$ 0.84	$ 1.22	$ 1.21	144%	$ (0.38)	(31)%

[redacted]							
Crude oil lease gathering purchases	742	620	612	122	20%	8	1%
[redacted]							
Waterborne cargos	21	68	55	(47)	(69)%	13	24%
[redacted]							

(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged crude oil inventory purchases) of approximately $20 million, $17 million, and $11 million for the years ended December 31, 2011, 2010, and 2009, respectively.

(3) The equity compensation expense presented in the reconciliation to segment profit above includes the portion of the equity compensation expense represented by outstanding awards under the LTIPs that, pursuant to the terms of the award, will be settled in cash only and have no impact on diluted units. The equity compensation expense presented in the Selected Items Impacting Comparability section of the table as shown in the Results of Operations-Non-GAAP Financial Measures discussion above excludes this portion of the equity compensation expense. See Note 10 to our Consolidated Financial Statements for additional discussion regarding our equity compensation plans.

(4) Calculated based on crude oil lease gathering purchased volumes, LPG sales volumes and waterborne cargo volumes.

The New York Mercantile Exchange (NYMEX) benchmark price of crude oil ranged from approximately $75 to $115 per barrel, $64 to $92 per barrel, and $33 to $82 per barrel during 2011, 2010, and 2009, respectively. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. The absolute amount of our revenues and purchases increased for all periods presented, resulting from higher commodity prices and increases in volumes in the comparative 2011 and 2010 periods.

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Generally, we expect a base level of earnings from our supply and logistics segment from the assets employed by this segment. This base level may be optimized and enhanced when there is a high level of market volatility, favorable basis differentials and/or a steep contango or backwardated market structure. A contango market is favorable to our commercial strategies that are associated with storage as it allows us to simultaneously purchase production at current prices for storage and sell at higher prices for future delivery. A backwardated market can have a positive impact on our lease gathering margins because crude oil gatherers can capture a premium for prompt deliveries. However, in a backwardated market, there is little incentive to store crude oil as current prices are above future delivery prices. Our supply and logistics segment operating results are further impacted by foreign currency translations adjustments as certain of our subsidiaries are based in Canada and use the Canadian dollar as their functional currency. Revenues and expenses are translated at average exchange rates prevailing for each month and comparison between periods may be impacted by changes in the average exchange rates. Also, our LPG marketing operations are weather-sensitive, particularly during the approximate five-month peak heating season of November through March, and temperature differences from period-to-period may have a significant effect on financial performance.

The following is a discussion of items impacting supply and logistics segment profit and segment profit per barrel for the periods indicated.

Operating Revenues and Volumes

2011 compared to 2010. Revenues, net of purchases and related costs, increased by approximately $542 million or 100% in 2011 compared to 2010. One of the principal drivers of this increase was the impact of higher volumes due to increased production related to the active development of crude oil and liquids-rich resource plays. The increase in volumes was primarily a result of increased drilling activities in the Bakken, Eagle Ford Shale, West Texas, Western Oklahoma and Texas Panhandle producing regions. Volumes also increased as a result of our December 2010 Nexen acquisition, which is primarily associated with the Bakken resource play. Another principal driver of our results was increased margins related to production volumes exceeding existing pipeline takeaway capacity in certain regions and the associated logistics challenges. As the infrastructure in these areas continues to be developed, we may not experience the same opportunities for enhanced margins that we have seen over the past year. We believe the fundamentals of our business remain strong; however, a normalization of margins may occur as the logistics challenges are addressed.

In addition, net revenues associated with our non-lease gathering activities increased for 2011 compared to 2010 as a result of (i) a more favorable market structure, (ii) more favorable crude oil quality differentials experienced in certain regions in 2011 and (iii) our mark-to-market valuation of our derivatives, as discussed further below. However, waterborne cargo volumes decreased over the 2011 period, which is primarily reflective of the increased domestic production.

2010 compared to 2009. Revenues, net of purchases and related costs, decreased by approximately $76 million or 12% in 2010 compared to 2009 despite our relatively consistent volumetric activity primarily due to (i) decreased LPG margins and (ii) our derivative activities (as shown in the table below). LPG margins for 2010 were negatively impacted by lower demand, while 2009 margins were higher than expected due to the liquidation of lower valued inventory following a write-down of inventory values during 2008. The 2010 period was also unfavorably impacted compared to 2009 due to (i) a less favorable market structure and (ii) less favorable crude oil quality differentials; however, these unfavorable variances were partially offset by improved margins within our lease gathering activities.

Impact from derivative activities. The impact of the mark-to-market valuation of our derivative activities on net revenues was as follows (in millions):

	For the Twelve Months Ended December 31,			Variance	
	2011	2010	2009	2011-2010	2010-2009
Gains/(losses) from derivative activities(1)	$ 62	$ (17)	$ 38	$ 79	$ (55)

(1) Includes mark-to-market gains and losses resulting from derivative instruments that are related to underlying activities in future periods or the reversal of mark-to-market gains and losses from the prior period. See Note 6 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and hedging activities.

Field Operating Costs and General and Administrative Expenses. Field operating costs and general and administrative expenses (excluding equity compensation expenses) increased year-over-year for each of the comparative periods primarily due to increased use of third-party contractors to truck lease gathered volumes, particularly in the Rockies, due to the Nexen acquisition completed in the fourth quarter of 2010.

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Equity Compensation Expense. Equity compensation expense increased for the comparative periods presented. See a discussion regarding such increases within the Transportation Segment above. Also, see Note 10 to our Consolidated Financial Statements for additional information on our equity compensation plans.

Other Income and Expenses

Depreciation and Amortization

Depreciation and Amortization. Depreciation and amortization expense was $249 million for the year ended December 31, 2011 compared to $256 million and $236 million for the years ended December 31, 2010 and 2009, respectively. Included within 2011 and 2010 depreciation expense are reductions resulting from extensions of the depreciable lives of several of our crude oil and other storage facilities and pipeline systems. The extension of depreciable lives is based on an internal review to assess the useful lives of our property and equipment and to adjust those lives, if appropriate, to reflect current expectations given actual experience and technology. The reductions of depreciation expense associated with the extensions of depreciable lives were $23 million in 2010 and $60 million (incrementally by $37 million as compared to the prior year) in 2011. This decrease was offset by an increased amount of assets resulting from our acquisition activities, including Southern Pines and Nexen in 2011 and PNGS and a natural gas processing business in 2010 as well as various internal growth projects in both years.

Included in depreciation expense for the years ended December 31, 2011, 2010 and 2009 are net losses of approximately $11 million, $13 million and $1 million, respectively, recognized upon disposition of certain assets and impairments for assets taken out of service. Amortization of debt issue costs was $7 million, $7 million and $6 million in 2011, 2010 and 2009, respectively.

Interest Expense

Interest expense was $253 million for the year ended December 31, 2011, compared to $248 million and $224 million for the years ended December 31, 2010 and 2009, respectively. Interest expense is primarily impacted by:

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

- interest capitalized on capital projects.

The following table summarizes the components impacting the interest expense variance for the years ended December 31, 2011 and 2010 (in millions, except for percentages):

		$	Average LIBOR Rate	Weighted Average Interest Rate (1)
Interest expense for the year ended December 31, 2009	$	224	0.3%	6.0%
Impact of retirement of senior notes (2)(3)		(21)		
Impact of issuance of senior notes (4)(5)		48		
Other		(3)		
Interest expense for the year ended December 31, 2010	$	248	0.3%	5.3%
Impact of retirement of senior notes (3)(6)		(22)		
Impact of issuance of senior notes (5)(7)		38		
Impact of capitalized interest		(9)		
Impact of credit facilities		(6)		
Other		4		
Interest expense for the year ended December 31, 2011	$	253	0.1%	5.4%

(1) Excludes commitment and other fees.

(2) During 2009, we redeemed our outstanding $250 million 7.125% senior notes due 2014, and our $175 million 4.75% notes matured.

(3) In September 2010, we redeemed our outstanding $175 million 6.25% senior notes due 2015.

(4) During 2009, we issued $1.35 billion of senior notes (see Liquidity and Capital Resources *Equity and Debt Financing Activities* below for additional discussion).

(5) In July 2010, we completed the issuance of $400 million of 3.95% senior notes due 2015.

(6) In February 2011, we redeemed our outstanding $200 million 7.75% senior notes due 2012.

(7) In January 2011, we completed the issuance of $600 million of 5.00% senior notes due 2021.

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Interest costs attributable to borrowings for inventory stored in a contango market are included in purchases and related costs in our supply and logistics 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 $20 million, $17 million, and $11 million for the years ended December 31, 2011, 2010, and 2009, respectively.

Other Income/(Expense), Net

Other income/(expense), net for the year ended December 31, 2011, was primarily impacted by (i) a loss of approximately $23 million that was recognized in conjunction with the early redemption of our $200 million, 7.75% senior notes in February 2011 and (ii) a net gain of approximately $4 million related to foreign currency revaluations of CAD-denominated interest receivables associated with intercompany notes and the impact of related foreign currency hedges.

The 2010 period primarily included (i) a loss of approximately $6 million recognized in connection with the early redemption of our $175 million 6.25% senior notes, (ii) the revaluation of contingent consideration related to our PNGS acquisition of approximately $2 million and (iii) a net loss of approximately $2 million related to the foreign currency revaluation of a CAD-denominated interest receivable associated with an intercompany note and the impact of related foreign currency hedges.

Other income/(expense), net for the year ended December 31, 2009 was primarily impacted by (i) a net gain of approximately $9 million recognized in connection with the PNGS acquisition (see Note 3 to our Consolidated Financial Statements for further discussion), (ii) a net gain of approximately $11 million related to the foreign currency revaluation of a CAD-denominated interest receivable associated with an intercompany note and the impact of related foreign currency hedges and (iii) a loss of approximately $4 million recognized in conjunction with the early redemption of our $250 million 7.13% senior notes.

Income Tax Expense

Current income tax expense increased for year ended December 31, 2011 compared to the year ended December 31, 2010 primarily due to an increase in the level of taxable earnings in our entities subject to Canadian federal and provincial taxes. As a result of Canadian tax legislation changes, we restructured our Canadian investment on January 1, 2011 and all of our Canadian operations are subject to Canadian corporate tax at a rate of approximately 27% in 2011. In addition, payments of interest and dividends from our Canadian entities to other affiliates are subject to Canadian withholding tax which is also treated as income tax expense. Previously, a portion of the activities were conducted in a flow-through entity that was not subject to entity-level taxation. Current income tax expense decreased in 2010 compared to 2009 due to a decrease in the level of taxable earnings in that year in our entities subject to Canadian federal and provincial taxes. There was a deferred tax expense increase for 2011 compared to 2010 and 2010 compared to 2009 due to a decrease in book depreciation rates. Tax depreciation is now in excess of book depreciation. See Note 7 to our Consolidated Financial Statements for further discussion.

Outlook

Although the U.S. and European economies remain weak and face significant uncertainties, on balance, we believe current and foreseeable U.S. energy industry fundamentals are favorable for PAA s asset base and business model. On the negative side, U.S. petroleum consumption has averaged around 19.1 million barrels per day for the last few years, a level that is approximately 8% below levels experienced in 2005 to 2007. Conversely, as a result of attractive crude oil and liquids prices, advances in drilling and completion techniques and their application to a number of large-scale shale and resource plays, U.S. crude oil and liquids production has increased in multiple regions in the lower 48 states. This production increase represents a reversal of multiple decades of declining production levels. A significant portion of these U.S. drilling activities is focused in areas where we have a significant asset presence, increasing the utilization of our existing assets as well as providing multiple opportunities to expand and extend our existing asset base on attractive terms.

Additionally, the crude oil market has experienced volatility in location and basis differentials as a result of international supply concerns, the quality of domestic production increases and regional infrastructure constraints. During 2011, these market conditions had a positive impact on our profitability as our business strategy and asset base positioned us to capitalize on opportunities available in a volatile environment. If these volatile market conditions persist, we believe we will have the opportunity to optimize the use of our existing assets.

There can be no assurance that U.S. production increases will continue or that we will not be negatively affected by potential volatility or challenging capital markets conditions. Additionally, construction of additional infrastructure by us and our competitors will likely reduce the infrastructure constraints, which will ultimately reduce unit margins and we cannot be certain that our expansion efforts will generate targeted returns or that any future acquisition activities will be successful. See Item 1A. Risk Factors - Risks Related to Our Business.

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Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) our cash flow from operations as further discussed below in the section entitled Cash Flow from Operations and (ii) borrowings under our credit facilities. Our primary cash requirements include, but are not limited to (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil and other products and other expenses and interest payments on our outstanding debt, (ii) maintenance and expansion activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on our long-term debt and (v) distributions to our unitholders and general partner. We generally expect to fund our short-term cash requirements through our primary sources of liquidity. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions, through a variety of sources (either separately or in combination), which may include operating cash flows, borrowings under our credit facilities, and/or the issuance of additional equity or debt securities. As of December 31, 2011, we had a working capital deficit of approximately $160 million and over $3.6 billion of liquidity available to meet our ongoing operational, investing and finance needs as of December 31, 2011 as noted below (in millions):

		As of December 31, 2011
Availability under PAA senior unsecured revolving credit facility	$	1,560
Availability under PAA senior secured hedged inventory facility		752
Availability under PNG senior unsecured revolving credit facility		126
Availability under PAA senior unsecured 364-day revolving credit facility (1)		1,200
Cash and cash equivalents		26
Total	$	3,664

(1) As of December 31, 2011, this facility had not been activated. See Credit Facilities and Indentures for more information regarding this credit facility.

We believe that we have and will continue to have the ability to access our credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a materially adverse effect on our financial condition, results of operations or cash flows. Also, see Item 1A. Risk Factors for further discussion regarding such risks that may impact our liquidity and capital resources. Usage of the credit facilities is subject to ongoing compliance with covenants. We are currently in compliance with all covenants.

During 2010, Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act). Although the Dodd-Frank Act includes provisions regarding the use of financial instruments, and the scope and applicability of these provisions as implemented may continue to develop, our current assessment is that the direct effects of the Dodd-Frank Act on PAA will be limited to additional documentation and record-keeping requirements. We cannot, however, predict the effect the Dodd-Frank Act may have on the futures and capital markets, which may affect the depth and quality of our counterparties and lenders and, as a result, our liquidity and access to capital.

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Cash Flow from Operations

The primary drivers of cash flow from our operations are (i) the collection of amounts related to the sale of crude oil and other products, the transportation of crude oil and other products for a fee, and storage and terminalling services provided for a fee and (ii) the payment of amounts related to the purchase of crude oil and other products and other expenses, principally field operating costs, general and administrative expenses and interest expense. The cash settlement from the purchase and sale of crude oil during any particular month typically occurs within thirty days from the end of the month, except (i) in the months that we store the purchased crude oil and hedge it by selling it forward for delivery in a subsequent month because of contango market conditions or (ii) in months in which we increase our share of linefill or long-term inventory. In addition, our cash flow from operations may be impacted by the timing of settlement of our derivative activities. Gains and losses from settled instruments that qualify as effective cash flow hedges are deferred in AOCI, but may impact operating cash flow in the period settled.

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

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

Net cash flow provided by operating activities for the twelve months ended December 31, 2011 was approximately $2.4 billion. The cash provided by operating activities reflects cash generated by our recurring operations, and is also significantly impacted in periods when we are increasing or decreasing the amount of inventory in storage as discussed above. During 2011, we reduced our overall inventory levels resulting in a positive impact to operating cash flow. The reduction in our crude oil inventory levels is primarily due to liquidating a certain amount of inventory that had been stored in the contango market, which primarily began liquidating during the latter portion of the second quarter, as well as liquidating the inventory stored through our waterborne cargo purchase activity, which occurred throughout the third and fourth quarters.

Net cash flows provided by operating activities for the twelve months ended December 31, 2010 and 2009 were approximately $259 million and $365 million, respectively. During both the 2010 and 2009 periods, we increased the amount of our inventory. The increases were due to both increased volumes and prices and were primarily related to our crude oil storage activities and, for 2010, our LPG activities. The net increased levels of inventory were financed through borrowings under our credit facilities and senior notes issuances resulting in a negative impact to our operating cash flow for the period.

Credit Facilities and Indentures

PAA senior unsecured 364-day revolving credit agreement. In December, 2011 we entered into a 364-day credit facility agreement with a borrowing capacity of $1.2 billion. As of December 31, 2011 this facility had not been activated. Pursuant to its terms, PAA may activate the facility at any time over a six-month period, resulting in a maturity 364 days from the activation date. Borrowings accrue interest based, at our election, on either the Eurocurrency Rate or the Base Rate, in each case plus a margin based on our credit rating at the applicable time.

PAA senior unsecured revolving credit facility. In August 2011, we entered into an unsecured revolving credit agreement with a committed borrowing capacity of $1.6 billion (including a $600 million Canadian sub-facility) which contains an accordion feature that enables us to increase the committed capacity to $2.1 billion, subject to obtaining additional or increased lender commitments. The credit agreement provides for the issuance of letters of credit and has a maturity date in August 2016. Borrowings accrue interest based, at our election, on the Eurocurrency Rate, the Base Rate or the Canadian Prime Rate, in each case plus a margin based on our credit rating at the applicable time. This facility replaced a similar $1.6 billion senior unsecured revolving credit facility that was scheduled to mature in July 2012. At December 31, 2011, we had approximately $1.56 billion of available borrowing capacity under our $1.6 billion committed revolving credit facility. Of the capacity we utilized at December 31, 2011, approximately $7 million was associated with outstanding letters of credit and the remainder was borrowed.

PAA senior secured hedged inventory facility. In August 2011, we replaced our previous $500 million senior secured hedged inventory facility that was scheduled to mature in October 2011 with a new $850 million senior secured hedged inventory facility (of which $250 million is available for the issuance of letters of credit) that expires in August 2013. Subject to obtaining additional or increased lender commitments, the committed amount of this new facility may be increased to $1.35 billion. Initial proceeds from the facility were used to refinance the outstanding balance of the previous facility, and subsequent proceeds from this facility will be used to finance purchased or stored hedged inventory. Obligations under the new committed facility are secured by the financed inventory and the associated accounts receivable and will be repaid from the proceeds of the sale of the financed inventory. Borrowings accrue interest based, at our election, on either the Eurocurrency Rate or the Base Rate, in each case plus a margin based on our credit rating at the applicable time. At December 31, 2011, we had approximately $752 million of available borrowing capacity under our $850 million committed hedged inventory facility. Of the capacity we utilized at December 31, 2011, approximately $23 million was associated with outstanding letters of credit and the remainder was borrowed.

PNG senior unsecured revolving credit facility. In August 2011, our consolidated subsidiary PNG entered into a five year, $450 million senior unsecured credit agreement , which provides for (i) $250 million under a revolving credit facility, which may be increased at PNG s option to $450 million (subject to receipt of additional or increased lender commitments) and (ii) two $100 million term loan facilities (the GO Zone term loans) pursuant to the purchase, at par, of the GO Bonds acquired by PNG in conjunction with the Southern Pines Acquisition (see Note 3 to our Consolidated Financial Statements). The revolving credit facility expires in August 2016, and the purchasers of the two GO Zone term loans have the right to put, at par, to PNG the GO Zone term loans in August 2016. The GO Bonds mature by their terms in May 2032 and August 2035, respectively. Borrowings under the revolving credit facility accrue interest, at PNG s election, on either the Eurodollar Rate or the Base Rate, in each case plus an applicable margin. The GO Zone term loans accrue interest in accordance with the interest payable on the related GO Bonds purchased with respect thereto as provided in such GO Bonds and the GO Bonds Indenture pursuant to which such GO Bonds are issued and governed. At December 31, 2011, PNG had approximately $126 million of available borrowing capacity under the revolving credit facility. Of the capacity we utilized at December 31, 2011, approximately $3 million was associated with outstanding letters of credit and the remainder was borrowed. This credit facility restricts, among other things, PNG s ability to make distributions of available cash to unitholders if any default or event of default, as defined in the credit agreement, exists or would result therefrom. In addition, the credit facility contains certain financial and other restrictive covenants.

Indentures. We had several issues of senior debt outstanding at December 31, 2011 that totaled approximately $4.8 billion, excluding premium or discount, range in size from $150 million to $600 million and mature at various dates between 2012 and 2037. See Note 4 to our Consolidated Financial Statements.

Our credit agreements and the indentures governing our senior notes contain cross-default provisions. A default under our credit facilities would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with the provisions in 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. See Note 4 to our Consolidated Financial Statements for additional discussion regarding our credit facilities and long-term debt.

Equity and Debt Financing Activities

Our financing activities primarily relate to funding acquisitions and internal capital projects, and short-term working capital and hedged inventory borrowings related to our LPG business, contango market activities, and waterborne cargo activities as well as refinancing of our debt maturities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under our credit facilities.

Registration Statements. We periodically access the capital markets for both equity and debt financing. We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $2.0 billion of debt or equity securities (Traditional Shelf). At December 31, 2011, we had $2.0 billion of unsold securities available under the Traditional Shelf. We also have access to a universal shelf registration statement (WKSI Shelf), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. Our January 2011offering of our $600 million 5.00% senior notes due 2021 and our March 2011 and November 2011 equity offerings, as discussed further below, were all conducted under the WKSI Shelf.

PNG has filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows PNG to issue up to an aggregate of $1.0 billion of debt or equity securities. PNG has not issued any securities under its shelf registration statement.

During August 2011, Vulcan Energy Corporation completed a secondary public offering of 7,500,000 common units representing limited partner interests in us at $61.10 per common unit. We did not receive any of the proceeds from the offering, and the number of PAA common units outstanding did not change as a result of this transaction. The secondary offering was not conducted under our Traditional Shelf or WKSI Shelf, but was conducted under a previously filed resale shelf registration statement.

PAA Equity Offerings. We completed equity offerings during 2011, 2010, and 2009 as summarized in the table below (net proceeds in millions). These offerings include our general partner s proportionate capital contributions and are net of costs associated with the offerings.

Year	**Units**		**Net Proceeds (1)**
2011	13,935,000	$	889
2010	4,780,000	$	296
2009	11,040,000	$	456

(1) We used the net proceeds to reduce outstanding borrowings under our credit facilities and for general partnership purposes. Amounts repaid under our credit facilities may be reborrowed to fund our ongoing capital program, potential future acquisitions or for general partnership purposes.

PNG Equity Offerings. On May 5, 2010, PNG completed its IPO of 13.5 million common units representing limited partner interests at $21.50 per common unit for total proceeds of approximately $268 million. Additionally, in conjunction with the Southern Pines Acquisition, PNG completed a private placement of 17.4 million common units to third parties for net proceeds of approximately $370 million, and the sale to us of approximately 10.2 million PNG common units for approximately $230 million, including our proportionate general partner contribution of $12 million. Our aggregate ownership interest in PNG is approximately 64%. See Note 5 to our Consolidated Financial Statements.

Senior Notes. During the last three years we issued senior unsecured notes as summarized in the table below (in millions):

Year	**Description**	**Maturity**		**Face Value**		**Net Proceeds(1)**
2011	5.00% Senior Notes issued at 99.521% of face value (2)	February 2021	$	600	$	597
2010	3.95% Senior Notes issued at 99.889% of face value (3)	September 2015	$	400	$	400
2009	5.75% Senior Notes issued at 99.523% of face value (4)	January 2020	$	500	$	499
	4.25% Senior Notes issued at 99.802% of face value	September 2012	$	500	$	497
	8.75% Senior Notes issued at 99.994% of face value	May 2019	$	350	$	350

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

(2) We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities and for general partnership purposes. In addition, we used a portion of the proceeds to redeem all of our outstanding $200 million 7.75% senior notes due 2012, as discussed further below.

(3) We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities. In addition, we used a portion of the proceeds to redeem all of our outstanding $175 million 6.25% senior notes due 2015, as discussed further below.

(4) We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities, a portion of which was used to fund the cash requirements of the PNGS acquisition (which included repayment of all of PNGS s debt). In addition, we used a portion of the proceeds to redeem all of our outstanding $250 million 7.13% senior notes due 2014 (in conjunction with the early redemption of these notes, we recognized a loss of approximately $4 million).

In February 2011, our $200 million 7.75% senior notes due 2012 were redeemed in full. In conjunction with the early redemption, we recognized a loss of approximately $23 million. We utilized cash on hand and available capacity under our credit facilities to redeem these notes.

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In September 2010, we repaid our $175 million 6.25% senior notes and recognized a loss of approximately $6 million in conjunction with the early redemption of these notes. We utilized net proceeds from our July 2010 issuance of $400 million 3.95% senior notes to retire these senior notes.

In August 2009, our $175 million 4.75% senior notes matured. We utilized cash on hand and available capacity under our credit facilities to retire these senior notes.

Acquisitions, Capital Expenditures and Distributions Paid to Our Unitholders, General Partner and Noncontrolling Interests

In addition to operating needs discussed above, we also use cash for our acquisition activities, internal growth projects and distributions paid to our unitholders, general partner and noncontrolling interests. 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. See Acquisitions and Internal Growth Projects for further discussion of such capital expenditures.

Acquisitions. The price of the acquisitions includes cash paid, 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.

In December 2011, we entered into a definitive agreement to acquire all of the outstanding shares of BP Canada Energy Company for a total consideration of approximately $1.67 billion with an expected closing to occur during the second quarter of 2012 (see Note 3 to our Consolidated Financial Statements). Giving effect to this transaction, our available liquidity as of December 31, 2011 of over $3.6 billion would have decreased to approximately $2 billion.

2012 Capital Expansion Projects. We expect the majority of funding for our 2012 capital program will be provided by revolver borrowings and cash flow in excess of partnership distributions as well as through our access to the capital markets for equity and debt as we deem necessary. Our 2012 capital expansion program includes the following projects with the estimated cost for the entire year (in millions):

Projects		**2012**
Eagle Ford Project	$	160
Spraberry Area Pipeline Projects		75
Mississippian Lime Pipeline		60
PAA Natural Gas Storage (multiple projects)		58
Rainbow II Pipeline		50
Bakken North		50
Ross Rail Project		45
St. James Phase IV		40
Shafter Expansion		40
Gardendale Gathering System		40
Yorktown Terminal Project		35

BP NGL Acquisition Related Projects		30			
Dollard Custom Treating & Truck Terminal		25			
Other projects (1)		142			
	$	850			
Potential Adjustments for Timing/Scope Refinement (2) (3)	-	$50		+	$100
Total Projected Expansion Capital Expenditures	$	800	to	$	950
Maintenance Capital	$	130	to	$	150

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(1) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2011.

(2) Potential variation to current capital costs estimates may result from changes to project design, final cost of materials and labor and timing of incurrence of costs due to uncontrollable factors such as regulatory approvals and weather.

(3) Amounts include preliminary forecasts for the BP NGL acquisition with an assumed closing date of April 1, 2012. Such forecast is preliminary and subject to change.

Distributions to our 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

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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. On February 14 , 2012, we paid a quarterly distribution of $1.025 per limited partner unit. This distribution represented a year-over-year distribution increase of approximately 7.0%. See Note 5 to our Consolidated Financial Statements for details of distributions paid. Also, see Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities Cash Distribution Policy for additional discussion on distributions.

Upon closing of the Pacific, Rainbow and PNGS acquisitions, our general partner agreed to reduce the amounts due it as incentive distributions. The final $1 million of incentive distribution reductions related to these acquisitions was applied to our November 2011 distribution.

Beginning with the first distribution paid after closing the BP NGL acquisition, which is anticipated to occur in the second quarter of 2012, our general partner has agreed to reduce the amount of its incentive distributions by $15 million per year for two years and $10 million per year thereafter. See Note 3 to our Consolidated Financial Statements for further discussion of the BP NGL acquisition.

Distributions to noncontrolling interests. We paid approximately $40 million and $10 million for distributions to our noncontrolling interests during the years ended December 31, 2011 and 2010, respectively. These amounts represent distributions paid on interests in PNG and SLC that are not owned by us.

We believe that we have sufficient liquid assets, cash flow from operations and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. We are, however, 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.

Contingencies

For a discussion of contingencies that may impact us, see Note 11 to our Consolidated Financial Statements.

Commitments

Contractual Obligations. In the ordinary course of doing business, we purchase crude oil and LPG from third parties under contracts, the majority of which range in term from thirty-day evergreen to five 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 purchases on the one hand and sales and future delivery obligations on the other. In addition, we enter into similar contractual obligations in conjunction with our natural gas operations. 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 entities that we deem creditworthy or who have provided credit support we consider adequate.

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, 2011 (in millions):

	2012	2013	2014	2015	2016	2017 and Thereafter	Total
Long-term debt, including current maturities and related interest payments(1)	$ 780	$ 516	$ 252	$ 793	$ 665	$ 4,768	$ 7,774
Leases (2)	71	55	47	41	33	292	539
Other obligations(3)	199	71	31	24	14	102	441
Pending BP NGL acquisition(4)	1,670						1,670
Subtotal	2,720	642	330	858	712	5,162	10,424
Crude oil, natural gas, LPG and other purchases(5)	4,325	558	243	131	101	25	5,383
Total	$ 7,045	$ 1,200	$ 573	$ 989	$ 813	$ 5,187	$ 15,807

(1) Includes debt service payments, interest payments due on our senior notes, interest payments and the commitment fee on the PNG credit agreement and the commitment fee on our PAA credit facilities. Although there is an outstanding balance on our PAA credit facilities at December 31, 2011, 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 (i) surface rentals, (ii) office rent, (iii) pipeline assets and (iv) trucks and railcars used in our gathering activities.

(3) Includes (i) other long-term liabilities, (ii) storage and transportation agreements and (iii) commitments related to our capital expansion projects. Excludes a non-current liability of approximately $114 million related to derivative activity included in Crude oil, natural gas, LPG and other purchases.

(4) In December 2011 we entered into a definitive agreement to acquire all of the outstanding shares of BP Canada Energy Company for total consideration of approximately $1.67 billion with an expected closing to occur during the second quarter of 2012. The closing of this acquisition is subject to a variety of conditions, including the receipt of various regulatory approvals.

(5) Amounts are primarily based on estimated volumes and market prices based on average activity during December 2011. The actual physical volume purchased and actual settlement prices will 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 supply and logistics activities, 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, 2011 and 2010, we had outstanding letters of credit of approximately $33 million and $75 million, respectively.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements as defined by Item 303 of Regulation S-K.

Investments in Unconsolidated Entities

We have invested in entities that are not consolidated in our financial statements. Certain of these entities are borrowers under credit facilities. We are neither a co-borrower nor a guarantor under any such facilities. We may elect at any time to make additional capital contributions to any of these entities. The following table sets forth selected information regarding these entities as of December 31, 2011 (unaudited, dollars in millions):

Entity	Type of Operation	Our Ownership Interest	Total Entity Assets	Total Cash and Restricted Cash	Total Entity Debt
Settoon Towing, LLC	Barge Transportation Services	50%	$ 170	$	$ 128
White Cliffs Pipeline, LLC	Crude Oil Pipeline	34%	$ 284	$ 4	$
Frontier Pipeline Company	Crude Oil Pipeline	22%	$ 27	$ 3	$

Butte Pipe Line Company	Crude Oil Pipeline	22%	$ 19	$ 3	$

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

We are exposed to various market risks, including volatility in (i) commodity prices for crude oil, refined products, natural gas and LPG, (ii) interest rates and (iii) currency exchange rates. Our policy is to use derivative instruments only for risk management purposes. We use various derivative instruments to manage such risks and, in certain circumstances, to realize incremental margin during volatile market conditions. Our risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring NYMEX, IntercontinentalExchange (ICE) and over-the-counter positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities and procedures and certain aspects of corporate risk management. Our risk management function also approves all new risk management strategies through a formal process. The following discussion addresses each category of risk.

Commodity Price Risk

We use derivative instruments to hedge our exposure to price fluctuations with respect to crude oil, refined products, natural gas and LPG in storage, and anticipated purchases and sales of these commodities. The derivative instruments utilized to manage our commodity price risk consist of futures, options and swaps traded on the NYMEX and ICE and in over-the-counter transactions. Our policy is (i) to purchase only product for which we have a market, (ii) to structure our sales contracts so that price fluctuations do not materially affect our operating income and (iii) not to acquire and hold physical inventory, futures contracts or other derivatives products for the purpose of speculating on outright commodity price changes, as these activities could expose us to significant losses.

Although we seek to maintain positions that are substantially balanced, we purchase crude oil, refined products and LPG from thousands of locations and may experience net unbalanced positions as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions and other uncontrollable events. When unscheduled

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physical inventory builds or draws do occur, they are monitored constantly and managed to a balanced position over a reasonable period of time.

The fair value of our commodity derivatives and the change in fair value that would be expected from a 10% price increase or decrease is shown in the table below (in millions):

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
Crude oil:			
Futures contracts	$ 14	$ 21	$ (21)
Swaps and options contracts	75	$ (14)	$ 16
LPG and other:			
Swaps and options contracts	4	$ (21)	$ 21
Total fair value	$ 93		

The fair value of our exchange-traded derivatives is based on quoted market prices obtained from the NYMEX or ICE. The fair value of our over-the-counter swaps and options contracts is estimated based on quoted prices from various sources such as independent reporting services, industry publications and brokers. The assumptions used in these estimates as well as the source for the estimates are maintained by the independent risk control function. See Note 6 to our Consolidated Financial Statements for further discussion. Price-risk sensitivities were calculated by assuming an across-the-board 10% increase or 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% change in near-term crude prices, the fair value of our derivative portfolio would typically change less than that shown in the table as changes in near-term prices are not typically mirrored in delivery months further out.

Interest Rate Risk

We use both fixed and variable rate debt, and are exposed to interest rate risk. Therefore, from time to time we use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and, in certain cases, outstanding debt instruments. All of our senior notes are fixed rate notes and thus not subject to interest rate risk. The majority of our variable rate debt at December 31, 2011, approximately $0.5 billion (including $150 million of interest rate derivatives that swap fixed rate debt for floating), is short-term debt and is subject to interest rate re-sets, which range from a week to three months. The average interest rate of 2.0% is based upon rates in effect during the year ended December 31, 2011. The fair value of our interest rate derivatives is an unrealized loss of approximately $137 million as of December 31, 2011. A 10% increase in the forward LIBOR curve as of December 31, 2011 would result in an increase of approximately $35 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of December 31, 2011 would result in a decrease of approximately $35 million to the fair value of our interest rate derivatives. See Note 6 to our Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

Currency Exchange Rate Risk

We use foreign currency derivatives to hedge foreign currency risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. The fair value of these instruments is an unrealized gain of approximately $1 million as of December 31, 2011. A 10% increase or decrease in the exchange rate (CAD-to-USD) would result in immaterial changes to the fair value of our foreign currency derivatives. See Note 6 to our Consolidated Financial Statements for a discussion of our currency exchange rate risk hedging.

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

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

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

None.

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

Disclosure Controls and Procedures

We maintain written disclosure controls and procedures, which we refer to as our DCP. Our DCP is designed to ensure that (i) information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 (the Exchange Act) is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and (ii) such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

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

Internal Control over Financial Reporting

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 GAAP. 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, 2011. See Management s Report on Internal Control Over Financial Reporting on page F-2 of our Consolidated Financial Statements.

Although we have made various enhancements to our controls, there have been no changes in our internal control over financial reporting during the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Certifications

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.

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

There was no information that was required to be disclosed in a report on Form 8-K during the fourth quarter of 2011 that has not previously been reported.

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PART III

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

Partnership Management and Governance

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

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 partnership agreement limits any fiduciary duties our general partner might owe to our unitholders. As a general partner, our general partner is liable for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Our general partner has the sole discretion to incur indebtedness or other obligations on our behalf on a non-recourse basis to the general partner. Our general partner has in the past exercised such discretion, in most instances involving payment liability, and intends to exercise such discretion in the future.

Our partnership agreement provides that our general partner will manage and operate us and that unitholders, unlike holders of common stock in a corporation, will have only limited voting rights on matters affecting our business or governance. The corporate governance of GP LLC is, in effect, the corporate governance of our partnership, subject in all cases to any specific unitholder rights contained in our partnership agreement. References to our Board of Directors mean the board of directors of GP LLC, which consists of eight directors elected by the members of GP LLC, and not by our unitholders. Under the Fifth 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. The remaining four seats are elected, and may be removed, by a majority of the membership interest. Directors filling three of these four at large seats must be independent. Any member that accumulates an interest greater than 25% and does not otherwise have a designation right may designate a director. In the event a member of GP LLC ceases to have the right to designate a director, the individual designated by such member is automatically removed as a director. Prior to August 2011, Vulcan Energy Corporation (Vulcan Energy) had the right to send an individual to attend board meetings in an observer capacity so long as it held in excess of 12 million units of PAA. In August 2011, Vulcan Energy s unit ownership dropped below the required threshold, thus terminating Vulcan Energy s board observer rights.

Voting rights agreements previously entered into by Vulcan Energy and Lynx Holdings I, LLC were terminated in December 2010 in connection with the sale by Vulcan Energy of its 50.1% interest in our general partner. Vulcan Energy has agreed that prior to the earlier of December 23, 2015 and the date, if any, of certain changes in our senior-most management, it will not vote any of its limited partner interests in favor of any proposal to remove GP LLC as our general partner.

Board Leadership Structure and Role in Risk Oversight

Our CEO also serves as Chairman of the Board. The board has no policy with respect to the separation of the offices of chairman and CEO; rather, that relationship is currently defined and governed by the GP LLC Agreement and the employment agreement with the CEO, which require coincidence of the offices. We do not have a lead independent director. The chairmanship of non-management executive sessions of the board rotates among the non-management directors, sequenced alphabetically by last name. Directors of GP LLC are designated or elected by the members of GP LLC. Accordingly, unlike holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business or governance, subject only to any specific unitholder rights contained in our partnership agreement.

The management of enterprise-level risk (ELR) may be defined as the process of identification, management and monitoring of events that present opportunities and risks with respect to creation of value for our unitholders. The board has delegated to management the primary responsibility for ELR management, while the board has retained responsibility for oversight of management in that regard. Management provides an ELR assessment to the Board at least once every year.

Non-Management Executive Sessions and Shareholder Communications

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

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

Independence Determinations and Audit Committee

Because we are a limited partnership, the listing standards of the NYSE do not require that we or our general partner have a majority of independent directors on the board, nor that we establish or maintain a nominating or compensation committee of the board. We are, however, required to have an audit committee consisting of at least three members, all of whom are required to be independent as defined by the NYSE.

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

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

None of the members of our audit committee has any relationships with either GP LLC or us, other than as a director and unitholder. For additional information regarding the experience and qualifications of our directors, please read the biographical descriptions under Directors, Executive Officers and Other Officers below.

Compensation Committee

Although not required by NYSE listing standards, we have a compensation committee that reviews and makes recommendations to the board regarding the compensation for the executive officers and administers our equity compensation plans for officers and key employees. The charter of our compensation committee is available on our website. See Meetings and Other Information for information on how to access or obtain copies of this charter. The compensation committee currently consists of Messrs. Petersen, Raymond and Sinnott and Ms. Sutil. Under applicable stock exchange rules, none of the members of our compensation committee is required to be independent. The compensation committee has the sole authority to retain any compensation consultants to be used to assist the committee, but did not retain any consultants in 2011. The compensation committee has delegated limited authority to the CEO to administer our long-term incentive plans with respect to employees other than executive officers.

Governance and Other Committees

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

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 will typically consist of a minimum of two members, none of whom can be (i) officers or employees of our general partner, (ii) directors, officers or employees of its affiliates or (iii) 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. See Item 13. Certain Relationships and Related Transactions, and Director Independence Transactions with Related Persons Review, Approval or Ratification of Transactions with Related Persons.

Meetings and Other Information

During the last fiscal year, our board of directors had five meetings, our audit committee had eight meetings, our compensation committee had two meetings and our governance committee had two meetings. All directors have access to members of management, and a substantial amount of information transfer and informal communication occurs between meetings. None of our

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directors attended fewer than 75% of the aggregate number of meetings of the board of directors and committees of the board on which the director served.

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

All of our standing committees have charters. Our committee charters and governance guidelines, as well as our Code of Business Conduct and our Code of Ethics for Senior Financial Officers, which apply to our principal executive officer, principal financial officer and principal accounting officer, are available on our Internet website at *http://www.paalp.com*. 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.

Audit Committee Report

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

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

The Partnership s independent registered public accounting firm, PricewaterhouseCoopers LLP, is responsible for expressing an opinion on the conformity of the audited financial statements with accounting principles generally accepted in the United States of America. The audit committee reviewed with PricewaterhouseCoopers LLP the firm s 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 Statement of Auditing Standards No. 61, as amended, as adopted by the Public Company Accounting Oversight Board. The committee received written disclosures and the letter from PricewaterhouseCoopers LLP required by applicable requirements of the Public Company Accounting Oversight Board regarding PricewaterhouseCoopers LLP s communications with the audit committee concerning independence, 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, 2011 for filing with the SEC.

Everardo Goyanes, *Chairman*
J. Taft Symonds
Christopher M. Temple

Directors, Executive Officers and Other Officers

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

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Name	Age (as of 12/31/11)	Position(1)
Greg L. Armstrong*(2)	53	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis*	54	President and Chief Operating Officer
Phillip D. Kramer*	55	Executive Vice President
John R. Rutherford*	51	Executive Vice President
Al Swanson*	47	Executive Vice President and Chief Financial Officer
W. David Duckett*	56	President Plains Midstream Canada
Mark J. Gorman*	57	Senior Vice President Operations and Business Development
Alfred A. Lindseth	42	Senior Vice President Technology, Process & Risk Management
John P. vonBerg*	57	Senior Vice President Commercial Activities
Jason Balasch	43	Vice President LPG of Plains Midstream Canada
Stephen L. Bart	51	Vice President Crude Oil Operations of Plains Midstream Canada
Samuel N. Brown	55	Vice President Pipeline Business Development
Kevin L. Cantrell	51	Vice President Internal Audit
David Craig	54	Executive Vice President and Chief Financial Officer of Plains Midstream Canada
Ralph R. Cross	56	Vice President Corporate Development and Transportation Services of Plains Midstream Canada
A. Patrick Diamond	39	Vice President
Lawrence J. Dreyfuss	57	Vice President, General Counsel Commercial & Litigation and Assistant Secretary
Roger D. Everett	66	Vice President Human Resources
James Ferrell	41	Vice President Supply Chain Management
James B. Fryfogle	60	Vice President Refinery Supply
M.D. (Mike) Hallahan	51	Vice President Crude Oil of Plains Midstream Canada
Chris Herbold*	39	Vice President Accounting and Chief Accounting Officer
Jim G. Hester	52	Vice President Natural Gas Gathering and Processing
John Keffer	52	Vice President Terminals
Charles Kingswell-Smith	60	Vice President and Treasurer
Gregg McClement	43	Vice President Business Development LPG of Plains Midstream Canada
Richard K. McGee	50	Vice President and Deputy General Counsel
Mike Mikuska	43	Vice President Business Development Crude Oil of Plains Midstream Canada
Tim Moore*	54	Vice President, General Counsel and Secretary
Daniel J. Nerbonne	54	Vice President Engineering
John F. Russell	63	Vice President West Coast Projects
Robert M. Sanford	62	Vice President Lease Supply
David Schwarz	42	Vice President Human Resources and Corporate Communication of Plains Midstream Canada
Scott Sill	49	Vice President LPG Operations of Plains Midstream Canada
Phil Smith	53	Vice President Operations
Troy E. Valenzuela	50	Vice President Environmental, Health and Safety
Sandi Wingert	41	Vice President Accounting of Plains Midstream Canada
David E. Wright	66	Vice President
Everardo Goyanes	67	Director and Member of Audit** Committee
Gary R. Petersen	65	Director and Member of Compensation and Governance Committees
John T. Raymond(2)	41	Director and Member of Compensation Committee
Robert V. Sinnott(2)	62	Director and Member of Compensation** Committee
Vicky Sutil(2)	47	Director and Member of Compensation Committee
J. Taft Symonds	72	Director and Member of Audit and Governance** Committees
Christopher M. Temple	44	Director and Member of Audit Committee

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

** Indicates chairman of committee.

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

(2) The GP LLC Agreement specifies that the Chief Executive Officer of the general partner will be a member of the board of directors. Under the GP LLC Agreement, three of the owners of our general partner have the right to appoint one director each to our board of directors. Mr. Raymond has been appointed by EMG Investment, LLC (EMG), of which he is Managing Partner and CEO. Mr. Sinnott has been appointed by KAFU Holdings, L.P., which is affiliated with Kayne Anderson Investment Management, Inc., of which he is President. Ms. Sutil has been appointed by Occidental Holding Company (Pipeline), Inc., a subsidiary of Occidental Petroleum Corporation (Oxy), of which she is Director, Corporate Development Midstream and Director, Business Development, Rockies. The remaining directors were elected by a majority of the membership interest. 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 a director and Chairman Pro Tem of the Federal Reserve Bank of Dallas, Houston Branch, and a director of National Oilwell Varco, Inc. Mr. Armstrong previously served as a director of BreitBurn Energy Partners, L.P. Mr. Armstrong is also a member of the advisory board of the Maguire Energy Institute at the Cox School of Business at Southern Methodist University, the National Petroleum Council and the Foundation for The Council on Alcohol and Drugs Houston. Mr. Armstrong is also Chairman, Chief Executive Officer and Director of PNGS GP LLC, a 100% owned subsidiary of PAA, which is the general partner of PAA Natural Gas Storage, L.P., a publicly traded MLP that is majority owned by PAA.

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 a director of Settoon Towing. Mr. Pefanis is also Vice Chairman and Director of PNGS GP LLC, a 100% owned subsidiary of PAA, which is the general partner of PAA Natural Gas Storage, L.P., a publicly traded MLP that is majority owned by PAA.

Phillip D. Kramer has served as Executive Vice President since November 2008 and previously served as Executive Vice President and Chief Financial Officer from our formation in 1998 until November 2008. 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.

John R. Rutherford has served as Executive Vice President since October 2010. Mr. Rutherford has 25 years of energy and investment banking experience, most recently serving as Managing Director and Head of North American Energy at Lazard, Freres & Co. Prior to joining Lazard, Mr. Rutherford worked at Simmons & Company International for 10 years, where he served as Managing Director and Partner and played a leadership role in building its financial advisory businesses in the mid-stream, downstream, and exploration and production sectors. During his career, Mr. Rutherford has developed substantial experience advising clients on mergers and acquisitions, corporate restructurings and other strategic actions, including many transactions in which he represented PAA.

Al Swanson has served as Executive Vice President and Chief Financial Officer since February 2011. He previously served as Senior Vice President and Chief Financial Officer from November 2008 through February 2011, as Senior Vice President Finance from August 2008 until November 2008 and as Senior Vice President Finance and Treasurer from August 2007 until August 2008. He served as Vice President Finance and Treasurer from August 2005 to August 2007, as Vice President and Treasurer from February 2004 to August 2005 and as Treasurer from May 2001 to February 2004. In addition, he held finance related positions at Plains Resources including Treasurer from February 2001 to May 2001 and Director of Treasury from November 2000 to February 2001. Prior to joining Plains Resources, he served as Treasurer of Santa Fe Snyder Corporation from 1999 to October 2000 and in various capacities at Snyder Oil Corporation including Director of Corporate Finance from 1998, Controller SOCO Offshore, Inc. from 1997, and Accounting Manager from 1992. Mr. Swanson began his career with Apache Corporation in 1986 serving in internal audit and accounting. Mr. Swanson is also Executive Vice President, Chief Financial Officer and Director of PNGS GP LLC, a 100% owned subsidiary of PAA, which is the general partner of PAA Natural Gas Storage, L.P., a publicly traded MLP that is majority owned by PAA.

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W. David Duckett has served as President of Plains Midstream Canada since June 2003, and served as Executive Vice President of Plains Midstream Canada from July 2001 to June 2003. Mr. Duckett was with CANPET Energy Group Inc. (CANPET) from 1985 to 2001, where he served in various capacities, including as President, Chief Executive Officer and Chairman of the Board.

Mark J. Gorman has served as Senior Vice President Operations and Business Development since August 2008. He previously served as Vice President from November 2006 until August 2008. Prior to joining Plains, he was with Genesis Energy in differing capacities as a Director, President and CEO, and Executive Vice President and COO from 1996 through August 2006. From 1992 to 1996, he served as a President for Howell Crude Oil Company. Mr. Gorman began his career with Marathon Oil Company, spending 13 years in various disciplines. Mr. Gorman is also a director of Settoon Towing, Butte, Frontier and SLC Pipeline.

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. Mr. Lindseth 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.

John P. vonBerg has served as Senior Vice President Commercial Activities since August 2008. Previously he served as Vice President Commercial Activities from August 2007 until August 2008 and as Vice President Trading from May 2003 until August 2007. He served as Director of these activities from January 2002 until May 2003. Prior to joining us in January 2002, he was with Genesis Energy in differing capacities as a Director, Vice Chairman, President and CEO from 1996 through 2001, and from 1993 to 1996 he served as a Vice President and a Crude Oil Manager for Phibro Energy USA. Mr. vonBerg began his career with Marathon Oil Company, spending 13 years in various disciplines.

Jason Balasch has served as Vice President LPG of Plains Midstream Canada since September 2011 and is responsible for overseeing all commercial activities associated with Plains LPG business including propane, butane and intermediates. Prior to joining Plains, he was with Enterprise Products Partners L.P. from June 2000 to August 2011, where he served in various capacities, most recently as Vice President, U.S. Gulf Coast Gathering & Processing in their Houston, Texas office. Mr. Balasch has also worked for Chevron and TransCanada Corporation in both engineering and business development roles.

Stephen L. Bart has served as Vice President Crude Oil Operations of Plains Midstream Canada 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.

Samuel N. Brown has served as Vice President Pipeline Business Development since October 2009. Prior to joining PAA, Mr. Brown served TEPPCO for over 10 years, most recently as Vice President Commercial Downstream and previously as Vice President Pipeline Marketing and Business Development for the Upstream segment. Prior to joining TEPPCO, Mr. Brown was with Duke Energy Transport and Trading Company.

Kevin L. Cantrell has served as Vice President Internal Audit since February 2011 and served as Managing Director of Internal Audit from April 2009 to February 2011. Prior to joining PAA, Mr. Cantrell was a managing director and founding member of Protiviti, Inc., a global risk consulting and internal audit firm, from May 2002 to April 2009, and a manager in Andersen s Risk Consulting practice in Houston, Texas, from February 1999 to May 2002, where he lead internal audit, risk management, and Sarbanes-Oxley compliance projects for clients in the Energy industry. Mr. Cantrell began his professional career at J.P. Morgan Chase, where he held positions of increasing responsibilities in the internal audit and capital markets compliance groups from July 1986 through February 1999.

David Craig has served as Executive Vice President and Chief Financial Officer of Plains Midstream Canada since June 2008. Prior to joining our Canadian operations, Mr. Craig was with Nexen Inc. from 2004 to June 2008, where he served in various capacities, including most recently as Vice President of natural gas marketing. From 1999 until 2004, he was with Apache Canada Ltd., with responsibilities in the areas of gas marketing and finance. Mr. Craig has over 25 years of experience in the energy industry in various financial roles (including accounting, planning, treasury, and mergers & acquisitions) as well as natural gas marketing.

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Ralph R. Cross has served as Vice President Corporate Development and Transportation Services of Plains Midstream Canada since July 2001. Mr. Cross was previously with CANPET since 1992, where he served in various capacities, including most recently as Vice President of Business Development.

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

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

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

James Ferrell has served as Vice President Supply Chain Management since August 2011. He joined Plains in 2006 from ConocoPhillips. He is responsible for functions all along the supply chain, including the majority of all purchasing requirements, all vendor contract negotiations, and fleet management.

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.

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

Chris Herbold has served as Vice President Accounting and Chief Accounting Officer since August 2010. He served as Controller of PAA from 2008 until August 2010. He previously served as Director of Operational Accounting from 2006 to 2008, Director of Financial Reporting and Accounting from 2003 to 2006 and Manager of SEC and Financial Reporting from 2002 to 2003. Prior to joining PAA in April 2002, Mr. Herbold spent seven years working for the accounting firm Arthur Andersen LLP.

Jim G. Hester has served as Vice President Gas Gathering and Processing since August 2011. He previously served as Vice President Acquisitions since March 2002. Prior to joining us, Mr. Hester was Senior Vice President Special Projects of Plains Resources. From May 2001 to December 2001, he was Senior Vice President Operations for Plains Resources. From May 1999 to May 2001, he was Vice President Business Development and Acquisitions of Plains Resources. He was Manager of Business Development and Acquisitions of Plains Resources from 1997 to May 1999, Manager of Corporate Development from 1995 to 1997 and Manager of Special Projects from 1993 to 1995. He was Assistant Controller from 1991 to 1993, Accounting Manager from 1990 to 1991 and Revenue Accounting Supervisor from 1988 to 1990.

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

Charles Kingswell-Smith has served as Vice President and Treasurer since August 2008. Mr. Kingswell-Smith previously served as Managing Director of GE Energy Financial Services from January 2008 to July 2008 and as Managing Director with Merrill Lynch Capital from March 2007 until January 2008. Prior to joining Merrill Lynch Capital, Mr. Kingswell-Smith spent 12 years in the energy banking business with JPMorgan Chase and BankOne.

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Gregg McClement has served as Vice President Business Development LPG of Plains Midstream Canada since December 2009. Mr. McClement has been with PMC and its predecessor CANPET since 2001. He previously held numerous senior management roles in the transportation industry with companies such as B.C. Rail and Union Pacific Railway.

Richard K. McGee has served as Vice President and Deputy General Counsel since August 2011. He also serves as Vice President Legal and Business Development for PNGS GP LLC, a position he has held since January 2010. He has served as Vice President of PAA s natural gas storage business since September 2009. From January 1999 to July 2009, he was employed by Duke Energy, serving as President of Duke Energy International from October 2001 through July 2009 and serving as general counsel of Duke Energy Services from January 1999 through September 2001. He previously spent 12 years at Vinson & Elkins L.L.P., where he was a partner with a focus on acquisitions, divestitures and development work for various clients in the energy industry.

Mike Mikuska has served as Vice President Business Development Crude Oil of Plains Midstream Canada since September 2008. Mr. Mikuska has been with PMC and its predecessor CANPET since 1995 and has served in various commercial and development roles over that time.

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

Daniel J. Nerbonne has served as Vice President Engineering since February 2005. Prior to joining us, Mr. Nerbonne was General Manager of Portfolio Projects for Shell Oil Products US from January 2004 to January 2005 and served in various capacities, including General Manager of Commercial and Joint Interest, with Shell Pipeline Company or its predecessors from 1998. From 1980 to 1998 Mr. Nerbonne held numerous positions of increasing responsibility in engineering, operations, and business development, including Vice President of Business Development from December 1996 to April 1998, with Texaco Trading and Transportation or its affiliates.

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

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

David Schwarz has served as Vice President Human Resources and Corporate Communications of Plains Midstream Canada since February 2011 and is responsible for overseeing all aspects of human resources and communications. He joined Plains Midstream Canada in August 2009 and brings over 18 years of experience to this role. Prior to joining Plains, Mr. Schwarz held various senior human resources roles in Calgary, and most recently served as Senior Manager, Human Resources in the ATCO Group of Companies. He has also gained experience working for such companies as Fluor Daniel, Manalta Coal and Superior Propane.

Scott Sill has served as Vice President LPG Operations of Plains Midstream Canada since March 2010. He joined Plains Midstream Canada in April 2006 through PAA s acquisition of the Shafter gas liquids processing facility. Prior to his most recent role as Managing Director of U.S. and Canadian LPG Operations, Mr. Sill performed the role of West Coast District Superintendent, overseeing an LPG isomerization/hydrotreating facility, salt cavern terminal, fractionation plant and various storage terminals. Mr. Sill brings over 20 years of LPG operations experience to this role.

Phil Smith has served as Vice President Operations since April 2010. He joined PAA in 2002 from Shell Pipeline. Mr. Smith is responsible for the Partnership s operations and maintenance activities on its domestic pipeline and terminal facilities.

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.

Sandi Wingert has served as Vice President Accounting of Plains Midstream Canada since February 2008. She has been with PMC and its predecessor CANPET acting as Controller since 2000. Prior to joining our Canadian operations, she held various accounting roles with Koch Petroleum and Ernst & Young.

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

Everardo Goyanes has served as a director of our general partner or former general partner since May 1999. He is Founder of Ex Cathedra LLC (a consulting firm). Mr. Goyanes served as Chairman of Liberty Natural Resources from April 2009 until August 2011. From May 2000 to April 2009, he was President and Chief Executive Officer of Liberty Energy Holdings, LLC (an energy investment firm). 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. From 1967 to 1982, Mr. Goyanes served in various financial and management capacities at Chase Bank, where his major emphasis was international and corporate finance to large independent and major oil companies. Mr. Goyanes received a BA in Economics from Cornell University and a Masters degree in Finance (honors) from Babson Institute. The Board of Directors has determined that Mr. Goyanes is independent under applicable NYSE rules and qualifies as an Audit Committee Financial Expert. Mr. Goyanes qualifications as an Audit Committee Financial Expert are supplemented by extensive experience comprising direct involvement in the energy sector over a span of more than 30 years. We believe that this experience, coupled with the leadership qualities demonstrated by his executive background bring important experience and skill to the Board.

Gary R. Petersen has served as a director of our general partner since June 2001. Mr. Petersen is Senior Managing Director of EnCap Investments L.P., an investment management firm which he co-founded in 1988. He is also a director of EV Energy Partners, L.P. He had previously served as Senior Vice President and Manager of the Corporate Finance Division of the Energy Banking Group for RepublicBank Corporation. Prior to his position at RepublicBank, he was Executive Vice President and a member of the Board of Directors of Nicklos Oil & Gas Company from 1979 to 1984. He served from 1970 to 1971 in the U.S. Army as a First Lieutenant in the Finance Corps and as an Army Officer in the Army Security Agency. He is a member of the Independent Petroleum Association of America, the Houston Producers Forum and the Petroleum Club of Houston. Mr. Petersen holds BBA and MBA degrees in finance from Texas Tech University. The Board of Directors has determined that Mr. Petersen is independent under applicable NYSE rules. Mr. Petersen has been involved in the energy sector for a period of more than 30 years, garnering extensive knowledge of the energy sectors various cycles, as well as the current market and industry knowledge that comes with management of approximately $9 billion of energy-related investments. In tandem with the leadership qualities evidenced by his executive background, we believe that Mr. Petersen brings numerous valuable attributes to the Board.

John T. Raymond has served as a director of our general partner since December 2010. Mr. Raymond is an owner and founder of EMG, a diversified natural resource private equity fund manager with over $4.0 billion under management, and has been Managing Partner and CEO since EMG s inception in 2006. Previous to that time, Mr. Raymond held leadership positions with various energy companies, including President and CEO of Plains Resources Inc. (the predecessor entity for Vulcan Energy), President and Chief Operating Officer of Plains Exploration and Production Company and Director of Development for Kinder Morgan, Inc. Mr. Raymond has been a direct or indirect owner of PAA s general partner since 2001 and served on the board of PAA s general partner from 2001 to 2005. Mr. Raymond received a BSM degree from the A.B. Freeman School of Business at Tulane University with dual concentrations in finance and accounting. We believe that Mr. Raymond s experience with investment in and management of a variety of upstream and midstream assets and operations provides a valuable resource to the Board.

Robert V. Sinnott has served as a director of our general partner or former general partner since September 1998. Mr. Sinnott is President, Chief Executive 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 CEO role in 2010. He is also President of Kayne Anderson Investment Management, Inc., the general partner of Kayne Anderson Capital Advisors, L.P. and he is a director of Kayne Anderson Energy Development Company and Kayne Anderson Midstream/Energy Fund Inc. 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. Mr. Sinnott s extensive investment management background includes his current role of managing approximately $6 billion of energy-related investments. Coupled with his direct involvement in the energy sector, spanning more than 30 years, the breadth of his current market and industry knowledge is enhanced by the depth of his knowledge of the various cycles in the energy sector. We believe that as a result of his background and knowledge, as well as the attributes of leadership demonstrated by his executive experience, Mr. Sinnott brings substantial experience and skill to the Board.

Vicky Sutil has served as a director of our general partner since December 2010. Ms. Sutil is Director, Corporate Development Midstream, and Director, Business Development Rockies, for Oxy, where she has led and worked on a variety of international and domestic oil and gas acquisitions. Her prior positions at Oxy have included Senior Manager, Corporate Development, Manager, Financial Planning and Analysis, and Senior Business Analyst. Before joining Oxy in 2000, Ms. Sutil worked for ARCO Products Company as a Business Analyst for the Refining and Retail Marketing divisions, and Senior Project Manager for the Refining Division. Earlier, she held a variety of engineering positions at Mobil Oil Corporation. Ms. Sutil served as Oxy s designated board observer from 2008, when Oxy acquired its initial interest in PAA s general partner, until December 2010. Ms. Sutil received a BS in Mechanical Engineering Petroleum Emphasis from the University of California, Berkeley, and an MBA from Pepperdine University. We believe that Ms. Sutil s financial and analytical background, coupled with her knowledge of engineering, provides the Board a distinctive and valuable perspective.

J. Taft Symonds has served as a director of our general partner since June 2001. Mr. Symonds is Chairman of the Board of Symonds Investment Company, Inc. (a private investment 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 was Chairman of the Houston Arboretum and Nature Center and currently serves as a director of Howard Supply Company LLC and Schilling Robotics LLC, where he serves on the audit committee. Mr. Symonds previously served as a director of Tetra Technologies Inc. Mr. Symonds received a BA from Stanford University and an MBA from Harvard. The Board of Directors has determined that Mr. Symonds is independent under applicable NYSE rules and qualifies as an Audit Committee Financial Expert. In addition to his qualifications as an Audit Committee Financial Expert, Mr. Symonds has a broad background in both commercial and investment banking, as well as investment management, all with a heavy emphasis on the energy sector. We believe that Mr. Symonds background offers to the Board a distinct and valuable knowledge base representative of both the capital and physical markets and refined by the leadership qualities evident from his executive experience.

Christopher M. Temple has served as a director of our general partner since May 2009. He is President of DelTex Capital LLC (a private investment firm). Mr. Temple served as the President of Vulcan Capital, the private investment group of Vulcan Inc., from May 2009 until December 2009 and as Vice President of Vulcan Capital from September 2008 to May 2009. Mr. Temple has served on the board of directors and audit committee of Clear Channel Outdoor Holdings since April 2011. Mr. Temple previously served on the board of directors and audit committee of Charter Communications, Inc. from November 2009 through January 2011. Prior to joining Vulcan in September 2008, Mr. Temple served as a managing director at Tailwind Capital LLC from May to August 2008. Prior to joining Tailwind, Mr. Temple was a managing director at Friend Skoler & Co., Inc. from May 2005 to May 2008. From April 1996 to December 2004, Mr. Temple was a managing director at Thayer Capital Partners. Additionally, Mr. Temple was a licensed CPA serving clients in the energy sector with KPMG in Houston, Texas from 1989 to 1993. Mr. Temple holds a BBA, magna cum laude, from the University of Texas and an MBA from Harvard. The Board of Directors has determined that Mr. Temple is independent under applicable NYSE rules and qualifies as an Audit Committee Financial Expert. Mr. Temple has a broad investment management background across a variety of business sectors, as well as experience in the energy sector. We believe that this background, along with the leadership attributes indicated by his executive experience, provide an important source of insight and perspective to the Board.

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 and 4 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 2011.

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Item 11. ***Executive Compensation***

Compensation Committee Report

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

In fulfilling its oversight responsibilities, the compensation committee reviewed and discussed with management the compensation discussion and analysis contained in this Annual Report on Form 10-K. Based on those reviews and discussions, the compensation committee recommended to the board of directors that the compensation discussion and analysis be included in the Annual Report on Form 10-K for the year ended December 31, 2011 for filing with the SEC.

Robert V. Sinnott, *Chairman*
Gary R. Petersen
John T. Raymond
Vicky Sutil

Compensation Committee Interlocks and Insider Participation

Messrs. Petersen and Sinnott served on the compensation committee throughout 2011, and Mr. Raymond and Ms. Sutil have served on the compensation committee since February 2011. No other persons served on the compensation committee during 2011. During 2011, none of the members of the compensation 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. Mr. Raymond is associated with EMG, Mr. Sinnott is associated with Kayne Anderson and its affiliates, and Ms. Sutil is associated with Oxy. We have relationships with these entities. See Item 13. Certain Relationships and Related Transactions, and Director Independence Transactions with Related Persons Other.

Compensation Discussion and Analysis

Background

All of our officers and employees (other than Canadian personnel) are employed by Plains All American GP LLC. Our Canadian personnel are employed by Plains Midstream Canada, which is a wholly owned subsidiary. Under our partnership agreement, we are required to reimburse our general partner and its affiliates for all employment-related costs, including compensation for executive officers, other than expenses related to the Class B units of Plains AAP, L.P.

Objectives

Since our inception, we have employed a compensation philosophy that emphasizes pay for performance, both on an individual and entity level, and places the majority of each Named Executive Officer s (defined in the Summary Compensation Table below) compensation at risk. The primary long-term measure of our performance is our ability to increase our sustainable quarterly distribution to our unitholders. We believe our pay-for-performance approach aligns the interests of our executive officers with that of our equity holders, and at the same time enables us to maintain a lower level of base overhead in the event our operating and financial performance is below expectations. Our executive compensation is designed to attract and retain individuals with the background and skills necessary to successfully execute our business model in a demanding environment, to motivate those individuals to reach near-term and long-term goals in a way that aligns their interest with that of our unitholders, and to reward success in reaching such goals. We use three primary elements of compensation to fulfill that design salary, cash bonus and long-term equity incentive awards. Cash bonuses and equity incentives (as opposed to salary) represent the performance driven elements. They are also flexible in application and can be tailored to meet our objectives. The determination of specific individuals cash bonuses is based on their relative contribution to achieving or exceeding annual goals and the determination of specific individuals long-term incentive awards is based on their expected contribution in respect of longer term performance objectives. We do not maintain a defined

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benefit or pension plan for our executive officers as we believe such plans primarily reward longevity and not performance. We provide a basic benefits package generally to all employees, which includes a 401(k) plan and health, disability and life insurance. In instances considered necessary for the execution of their job responsibilities, we also reimburse certain of our Named Executive Officers and other employees for club dues and similar expenses. We consider these benefits and reimbursements to be typical of other employers, and we do not believe they are distinctive of our compensation program.

Elements of Compensation

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

Cash Bonuses. Our cash bonuses include annual discretionary bonuses in which all of our current domestic Named Executive Officers potentially participate, as well as a quarterly bonus program in which Mr. vonBerg participates. Mr. Duckett participates in an annual and quarterly bonus program that is specific to activities managed by our Canadian personnel.

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

In 2007, the owners of Plains AAP, L.P. authorized the creation of Class B units of Plains AAP, L.P. and authorized GP LLC s compensation committee to issue grants of Class B units to create additional long-term incentives for our management designed to attract talent and encourage retention over an extended period of time. The entire economic burden of the Class B units is borne solely by Plains AAP, L.P., our general partner, and does not impact our cash or units outstanding.

The Class B units are subject to restrictions on transfer and generally become incrementally earned (entitled to participate in distributions) upon achievement of certain performance thresholds, which are aligned with the interests of our common unitholders. As of February 14, 2012, approximately 75% of the outstanding Class B units granted in 2007 and 2009 had been earned (or will be earned within 180 days), 25% of the Class B units granted in 2010 had been earned (with another 25% to be earned within 180 days), and 25% of the Class B units granted in 2011 will be earned within 180 days. No Class B units were granted in 2008.

To encourage retention following achievement of these performance benchmarks, Plains AAP, L.P. retained a call right to purchase any earned Class B units at a discount to fair market value that is exercisable upon the termination of a holder s employment with Plains All American GP LLC and its affiliates (subject to certain exceptions) prior to January 1, 2016 for Class B units granted in 2007 and 2009 (January 1, 2017 for Class B units granted in 2010 and January 1, 2020 for Class B units granted in 2011). A portion of unvested Class B units will vest (no longer be subject to the call right) upon a change of control. All earned Class B units will also vest if they remain outstanding as of January 1, 2016 for Class B units granted in 2007 and 2009 (January 1, 2017 for Class B units granted in 2010 and January 1, 2020 for Class B units granted in 2011) or Plains AAP, L.P. elects not to timely exercise its call right. See Item 13. Certain Relationships and Related Transactions, and Director Independence Transactions with Related Persons Our General Partner Class B Units of Plains AAP, L.P.

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Transaction/Transition Grants. In connection with the initial public offering of PNG in 2010, we created a plan based on PNG equity, which is designed to reward and create incentive for certain of our officers who were instrumental in developing the natural gas storage business and bringing it to the point of the IPO, and who will continue to allocate meaningful amounts of time to the business. In September 2010, we entered into transaction/transition grant agreements with Messrs. Armstrong, Pefanis and Swanson, pursuant to which they acquired phantom common units, phantom series A subordinated units and phantom series B subordinated units representing a portion of the limited partner interest of PNG issued to PAA in connection with PNG s IPO. These grants are intended to be transactional and transitional and are not expected to be a recurring component of these individual s compensation arrangements. Vesting terms are intended to align the interests of these individuals with those of PAA as such interests pertain to achieving specific future performance benchmarks that are significant to PNG and to PAA s equity holdings in PNG.

Relation of Compensation Elements to Compensation Objectives

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

We stress performance-based compensation elements to attempt to create a performance-driven environment in which our executive officers are (i) motivated to perform over both the short term and the long term, (ii) appropriately rewarded for their services and (iii) encouraged to remain with us even after meeting long-term performance thresholds in order to meet the minimum service periods and by the potential for rewards yet to come. We believe our compensation philosophy as implemented by application of the three primary compensation elements (i) aligns the interests of our Named Executive Officers with our unitholders, (ii) positions us to achieve our business goals, and (iii) effectively encourages the exercise of sound judgment and risk-taking that is conducive to creating and sustaining long-term value. We believe the processes employed by the compensation committee and by the board in applying the elements of compensation (as discussed in more detail below) provide an adequate level of oversight with respect to the degree of risk being taken by management to achieve short-term performance goals. See Relation of Compensation Policies and Practices to Risk Management.

We believe our compensation program has been instrumental in our achievement of stated objectives. Over the five-year period ended December 31, 2011, our annual distribution per common unit has grown at a compound annual rate of 5.8% and the total return realized by our unitholders for that period averaged approximately 15.0%. During this period, we have enjoyed a very high rate of retention among executive officers.

Application of Compensation Elements

Salary. We do not make systematic annual adjustments to the salaries of our Named Executive Officers. We do, however, make salary adjustments as necessary to maintain hierarchical relationships among senior management levels after new senior management members are added to keep pace with our overall growth. Since the date of our initial public offering in 1998 (or date of employment, if later) through December 31, 2011, Messrs. Armstrong, Pefanis and vonBerg have each received one salary adjustment, Mr. Duckett has received small salary adjustments in line with other Canadian personnel, and Mr. Swanson has received four salary adjustments in connection with taking on increasing responsibilities and promotions.

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

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

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

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

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

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

Long-Term Incentive Awards. We do not make systematic annual phantom unit awards to our Named Executive Officers. Instead, our objective is to time the granting of awards such that the creation of new long-term incentives coincides with the satisfaction of performance thresholds under existing awards. Thus, performance is rewarded by relatively greater frequency of awards and lack of performance by relatively lesser frequency of awards. Generally, we believe that a grant cycle of approximately three years (and extended time-vesting requirements) provides a balance between a meaningful retention period for us and a visible, reachable reward for the executive officer. Achievement of performance targets does not shorten the minimum service period requirement. If top performance targets on outstanding awards are achieved in the early part of this cycle, new awards are granted with higher performance thresholds, and the minimum service periods of the new awards are generally synchronized with the remaining time-vesting requirements of outstanding awards in a manner designed to encourage extended retention of our Named Executive Officers. Accordingly, these new arrangements inherently take into account the value of awards where performance levels have been achieved but have not yet vested due to ongoing service period requirements, but do not take into consideration previous awards that have fully vested.

As an additional means of providing longer-term, performance-based officer incentives that require extended periods of employment to realize the full benefit, in 2007 the owners of Plains AAP, L.P. authorized the creation of Class B units of Plains AAP, L.P., which the compensation committee of GP LLC is authorized to administer. See Elements of Compensation Long-Term Incentives. These Class B units are limited to 200,000 authorized units, of which approximately 183,500 were issued as of December 31, 2011 pursuant to individual restricted units agreements between Plains AAP, L.P. and certain members of management. As of December 31, 2011 our Named Executive Officers held 111,000 of the restricted Class B units. The remaining available Class B units are administered at the discretion of the compensation committee and may be awarded upon advancement, exceptional performance or other change in circumstance of an existing member of management, or upon the addition of a new individual to the management team.

Application in 2011

At the beginning of 2011, we established four public goals with paraphrased versions of these goals overlapping two of our four internal goals. As a result, we entered 2011 with six distinct goals for the year.

The four public goals for the year were to:

1. Deliver baseline operating and financial performance in line with guidance;

2. Successfully execute our 2011 capital program and set the stage for continued growth in 2012 and beyond;

3. Continue to pursue strategic and accretive acquisitions; and

4. Increase our November 2011 annualized distribution level by approximately 4% to 5% over the November 2010 annualized distribution level.

Our two internal qualitative goals included (i) advancing multi-year programs and initiatives and preparing the organization for future growth, and (ii) making something meaningfully positive happen.

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In general, we substantially achieved or exceeded all of these goals.

- Our adjusted EBITDA significantly exceeded the high end of our original guidance for 2011;

- We timely and cost-effectively executed an approximate $530 million expansion capital program, and refined and expanded our portfolio of organic growth projects, setting up a 2012 program of $800 million to $950 million;

- We completed and integrated the $765 million Southern Pines acquisition and consummated or entered into definitive agreements for five additional acquisitions aggregating approximately $2.3 billion;

- We increased our annualized distribution rate by 4.7% to $3.98 per common unit, while generating aggregate annual distribution coverage of approximately 146%;

- We raised approximately $1.9 billion in both long-term debt and equity capital, renewed $2.9 billion of bank credit facilities, added a new $1.2 billion bank liquidity facility, and ended the year with over $3.6 billion of liquidity and favorable credit metrics; and

- We continued to implement and expand our integrity management programs, improve communications throughout the organization and increase staffing in key growth areas.

The combination of our high level of execution during 2011, the magnitude of our excess performance against plan, our successful acquisition activities and our favorable positioning for growth in 2012 and future years support the conclusion that we were successful in making something meaningfully positive happen.

For 2011, the elements of compensation were applied as described below.

Salary. No salary adjustments for Named Executive Officers were recommended or made in 2011. See Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table.

Cash Bonuses. Based on the CEO s annual performance review and the individual performance of each of our Named Executive Officers, the compensation committee recommended to the board of directors and the board of directors approved the annual bonuses reflected in the Summary Compensation Table and notes thereto. Such amounts take into account the performance relative to our 2011 goals; the absence of shortfalls relative to expectations; the level of difficulty associated with achieving such objectives; our relative positioning at the end of the year with respect to future growth and performance; the significant transactions or accomplishments for the period not included in the goals for the year; and our positioning at the end of the year with respect to our targeted credit profile. In the case of Mr. Duckett, the aggregate bonus amount represented 40% of his participation level for the first three fiscal quarters and an annual payment consisting of 60% of his participation for the first three quarters and 100% of his participation for the fourth quarter. For Mr. vonBerg, the aggregate bonus amount represented approximately 38% in annual bonus and 62% in quarterly bonus.

Long-Term Incentive Awards. There were no grants of long-term incentive awards to Named Executive Officers in 2011.

Transaction/Transition Grants. There were no transaction/transition grants to Named Executive Officers in 2011.

Other Compensation Related Matters

Equity Ownership in PAA. As of December 31, 2011, our Named Executive Officers collectively owned substantial equity in the Partnership. Although we encourage our Named Executive Officers to acquire and retain ownership in the Partnership, we do not have a policy requiring maintenance of a specified equity ownership level. Our policies prohibit our Named Executive Officers from using puts, calls or options to hedge the economic risk of their ownership. As of December 31, 2011, our Named Executive Officers beneficially owned, in the aggregate, approximately 958,272 of our common units (excluding any unvested equity awards), an approximately 2.5% indirect ownership interest in our general partner and IDRs, and 111,000 Class B units of Plains AAP, L.P. Based on the market price of our common units at December 31, 2011 and an implied valuation for their collective general partner and IDR interests using similar valuation metrics, the value of the equity ownership of these individuals was significantly greater than the combined aggregate salaries and bonuses for 2011.

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

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

Change in Control Triggers. The employment agreements for Messrs. Armstrong and Pefanis, the long-term incentive plan grants to our Named Executive Officers, and the Class B restricted units agreements include severance payment provisions or accelerated vesting triggered upon a change of control, as defined in the respective agreements. In the case of the long-term incentive plan grants and transaction/transition grants, the provision becomes operative only if the change in control is accompanied by a change in status (such as the termination of employment by Plains All American GP LLC). We believe this double trigger arrangement is appropriate because it provides assurance to the executive, but does not offer a windfall to the executive when there has been no real change in employment status. The provisions in the employment agreements for Messrs. Armstrong and Pefanis become operative only if the executive terminates employment within three months of the change in control. Messrs. Armstrong and Pefanis agreed to a conditional waiver of these provisions with respect to Vulcan Energy s sale of its 50.1% general partner interest in December 2010. The Class B restricted units agreements generally call for vesting (upon a change in control) of any units that have already been earned, plus the next increment of units that could be earned at the next distribution threshold. Any remaining Class B restricted units would be forfeited (unless waived at the discretion of the general partner or acquirer as the case may be). As a result of significant participation by existing general partner owners or their affiliates in the December 2010 sale of Vulcan Energy s 50.1% ownership in the general partner, the change of control provisions of the Class B restricted units agreements were not triggered. See Employment Contracts and Potential Payments upon Termination or Change-in-Control. The provision of severance or equity acceleration for certain terminations and change of control help to create a retention tool by assuring the executive that the benefit of the employment arrangement will be at least partially realized despite the occurrence of an event that would materially alter the employment arrangement.

Relation of Compensation Policies and Practices to Risk Management

Our compensation policies and practices are designed to provide rewards for short-term and long-term performance, both on an individual basis and at the entity level. In general, optimal financial and operational performance, particularly in a competitive business, requires some degree of risk-taking. Accordingly, the use of compensation as an incentive for performance can foster the potential for management and others to take unnecessary or excessive risks to reach the performance thresholds. For us, such risks would primarily attach to certain commercial activities conducted in our supply and logistics segment as well as to the execution of capital expansion projects and acquisitions and the realization of associated returns.

From a risk management perspective, our policy is to conduct our commercial activities within pre-defined risk parameters that are closely monitored and are structured in a manner intended to control and minimize the potential for unwarranted risk-taking. See Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model; Risk Management in Part I of this annual report. We also routinely monitor and measure the execution and performance of our capital projects and acquisitions relative to expectations.

Our compensation arrangements contain a number of design elements that serve to minimize the incentive for unwarranted risk-taking to achieve short-term, unsustainable results, including delaying the reward and subjecting such rewards to forfeiture for terminations related to violations of our risk management policies and practices or of our code of conduct. In addition, our long-term incentive awards typically include vesting criteria

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based on payment of distributions from currently available cash. See Compensation Discussion and Analysis Relation of Compensation Elements to Compensation Objectives.

In combination with our risk-management practices, we do not believe that risks arising from our compensation policies and practices for our employees are reasonably likely to have a material adverse effect on us.

Summary Compensation Table

The following table sets forth certain compensation information for our Chief Executive Officer, Chief Financial Officer, and the three other most highly compensated executive officers in 2011 (our Named Executive Officers). We reimburse our general partner and its affiliates for expenses incurred on our behalf, including the costs of officer compensation (excluding the costs of the obligations represented by the Class B units).

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)(1)	All Other Compensation ($)(2)	Total ($)
Greg L. Armstrong	2011	375,000	5,000,000		15,900	5,390,900
Chairman and Chief Executive Officer	2010	375,000	3,250,000	5,868,436	15,900	9,509,336
	2009	375,000	3,000,000		15,800	3,390,800
Harry N. Pefanis	2011	300,000	4,800,000		15,900	5,115,900
President and Chief Operating	2010	300,000	3,100,000	3,946,511	15,900	7,362,411
Officer	2009	300,000	2,900,000		15,800	3,215,800
Al Swanson	2011	250,000	1,750,000		15,900	2,015,900
Executive Vice President and	2010	250,000	1,100,000	1,973,255	15,900	3,339,155
Chief Financial Officer	2009	250,000	1,000,000	376,483	15,763	1,642,246
W. David Duckett(3)	2011	288,799	4,017,220		106,744	4,412,763
President Plains Midstream	2010	276,927	3,625,092	1,119,153	98,079	5,119,251
Canada	2009	251,058	3,378,240		83,643	3,712,941
John P. vonBerg	2011	250,000	5,220,000(4)		15,900	5,485,900
Senior Vice President	2010	250,000	3,265,000(4)	805,790	15,900	4,336,690
Commercial Activities	2009	250,000	3,220,000(4)		15,800	3,485,800

(1) Grant date fair values are presented for (i) transaction/transition grants awarded to Messrs. Armstrong, Pefanis and Swanson, and (ii) LTIP phantom unit grants awarded to Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg. Dollar amounts represent the aggregate grant date fair value of transaction/transition grants and phantom units awarded during each year based on the probable outcome of underlying performance conditions pursuant to FASB ASC Topic 718. For transaction/transition grants awarded in 2010, vesting of 100% of the phantom common units and phantom series A subordinated units, and vesting of 20% of the phantom series B subordinated units, was deemed probable of occurrence on the grant date. For phantom units granted in 2009 and 2010, the performance threshold for the first tranche of vesting was deemed probable of occurrence on the grant date. The maximum grant date fair values of stock awards assuming that the highest level of performance conditions will be met are as follows:

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Name	Year	Maximum Grant Date Fair Value ($)
Greg L. Armstrong	2011	
	2010	12,229,929
	2009	
Harry N. Pefanis	2011	
	2010	8,198,147
	2009	
Al Swanson	2011	
	2010	4,099,073
	2009	1,129,450
W. David Duckett	2011	
	2010	3,357,459
	2009	
John P. vonBerg	2011	
	2010	2,417,371
	2009	

(2) Plains All American GP LLC matches 100% of employees contributions to its 401(k) plan in cash, subject to certain limitations in the plan. All Other Compensation for each of Messrs. Armstrong, Pefanis, Swanson and vonBerg includes $14,700 in such contributions for 2011. The remaining amount for each represents premium payments on behalf of such Named Executive Officer for group term life insurance. All Other Compensation for Mr. Duckett includes, for 2011, employer contributions to the Plains Midstream Canada savings plan of $37,544, group term life insurance premiums of $22,558, automobile lease payments of $39,838 and club dues of $6,804.

(3) Salary, bonus and all other compensation amounts for Mr. Duckett are presented in U.S. dollar equivalent based on the exchange rates in effect on the dates payments were made or approved.

(4) Includes quarterly bonuses aggregating $3,220,000, $1,865,000 and $1,920,000 and annual bonuses of $2,000,000, $1,400,000 and $1,300,000 in 2011, 2010 and 2009, respectively. The annual bonuses are payable 60% at the time of award and 20% in each of the two succeeding years.

Grants of Plan-Based Awards Table

There were no grants of plan-based awards to our Named Executive Officers during the fiscal year ended December 31, 2011.

Narrative Disclosure to Summary Compensation Table

A discussion of 2011 salaries and bonuses and how they fit into the overall compensation array is included in Compensation Discussion and Analysis. The following is a discussion of other material factors necessary to an understanding of the information disclosed in the Summary Compensation Table above.

Salary As discussed in this Item 11, we do not make systematic annual adjustments to the salaries of our Named Executive Officers. In that regard, no salary adjustments were made for any of our Named Executive Officers in 2011.

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Employment Contracts

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, including, but not limited to, requirement of law or prior disclosure by a third party) 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 2005, Mr. Armstrong s annual salary was increased to $375,000.

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 that the board of directors 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 2005, Mr. Pefanis annual salary was increased to $300,000.

See Compensation Discussion and Analysis for a discussion of how we use salary and bonus to achieve compensation objectives. See Potential Payments upon Termination or Change-In-Control for a discussion of the provisions in Messrs. Armstrong s and Pefanis employment agreements related to termination, change of control and related payment obligations.

Outstanding Equity Awards at Fiscal Year-End

The following table sets forth certain information regarding outstanding equity awards at December 31, 2011 with respect to our Named Executive Officers:

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	Unit Awards			
Name	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)(1)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(1)
Greg L. Armstrong	60,000(2)	4,407,000	60,000(2)	4,407,000
	20,000(3)	5,382,500	20,000(3)	3,375,600
	60,000(5)	4,407,000	120,000(5)	8,814,000
	31,000(6)	581,250		
			62,000(7)	1,162,500
			62,000(8)	1,162,500
Harry N. Pefanis	40,000(2)	2,938,000	40,000(2)	2,938,000
	15,000(3)	4,036,800	15,000(3)	2,531,700
	40,000(5)	2,938,000	80,000(5)	5,876,000
	21,000(6)	393,750		
			42,000(7)	787,500
			42,000(8)	787,500
Al Swanson	11,000(2)	807,950	11,000(2)	807,950
			23,334(4)	1,713,882
	5,000(3)	1,345,600	5,000(3)	843,900
	20,000(5)	1,469,000	40,000(5)	2,938,000
	10,500(6)	196,875		
			21,000(7)	393,750
			21,000(8)	393,750
W. David Duckett	25,000(2)	1,836,250	25,000(2)	1,836,250
	8,500(3)	2,287,520	8,500(3)	1,434,630
	25,000(5)	1,836,250	50,000(5)	3,672,500
John P. vonBerg	18,000(2)	1,322,100	18,000(2)	1,322,100
	7,000(3)	1,883,840	7,000(3)	1,181,460
	18,000(5)	1,322,100	36,000(5)	2,644,200

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(1) Market value of phantom units reported in these columns is calculated by multiplying the closing market price ($73.45) of our common units at December 30, 2011 (the last trading day of the fiscal year) by the number of units. Market value of transaction/transition grants reported in these columns is calculated by multiplying the closing market price ($18.75) of PNG s common units at December 30, 2011 (the last trading day of the fiscal year) by the number of units. No discount is applied for remaining performance threshold or service period requirements. The Class B units are valued based on the grant date fair value computed in accordance with FASB ASC Topic 718 assuming that the highest level of performance conditions will be met.

(2) Represents the balance of phantom units granted in 2007 under our Long-Term Incentive Plan. As of December 31, 2011, one-half of these phantom units had been earned and will vest upon the May 2012 distribution date. Upon payment of our February 2012 distribution, the unearned portion of these phantom units became earned and vested. All of the DERs associated with these phantom units are currently payable.

(3) Represents Class B units of Plains AAP, L.P. Each Class B unit represents a profits interest in Plains AAP, L.P., which entitles the holder to participate in future profits and losses from operations, current distributions from operations, and an interest in future appreciation or depreciation in Plains AAP, L.P. s asset values, but does not represent an interest in the capital of Plains AAP, L.P. on the applicable grant date of the Class B units. As of December 31, 2011, 50% of the Class B units held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg had been earned. None of the Class B units have vested. For additional information regarding the Class B units, please read Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner Class B Units of Plains AAP, L.P.

(4) Represents the balance of phantom units granted in 2009 under our Long-Term Incentive Plan. None of these phantom units had been earned as of December 31, 2011. Upon payment of our February 2012 distribution, one-half of these phantom units became earned and will vest upon the May 2012 distribution date. The other half of these phantom units will vest upon the later of the May 2013 distribution date and the date on which we pay a quarterly distribution of at least $1.0625. All of the DERs associated with these phantom units are currently payable. Any phantom units that have not vested (and all associated DERs) as of the May 2015 distribution date will expire.

(5) Represents phantom units granted in 2010 under our Long-Term Incentive Plan. As of December 31, 2011, one-third of these phantom units had been earned and will vest upon the May 2013 distribution date. Upon payment of our February 2012 distribution, one-half of the unearned portion of these phantom units became earned and will vest upon the May 2014 distribution date. The balance of the unearned portion of these phantom units will vest upon the later of the May 2015 distribution date and the date on which we pay a quarterly distribution of at least $1.05. Two-thirds of the DERs associated with these phantom units are currently payable. The remaining DERs become payable upon achieving a quarterly distribution level of $1.05 per unit. Any phantom units that have not vested (and all associated DERs) as of the May 2016 distribution date will expire.

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(6) Represents the balance of phantom common units under transaction/transition grants. These phantom common units will vest on May 5, 2012, and be payable one-for-one by PAA in Common Units of PNG.

(7) Represents phantom series A subordinated units under transaction/transition grants. These phantom series A subordinated units will vest in connection with the conversion of PNG s Series A Subordinated Units into PNG Common Units, and be payable one-for-one by PAA in Common Units of PNG. Any of these phantom series A subordinated units that have not vested as of December 31, 2018 will be automatically cancelled on such date.

(8) Represents phantom series B subordinated units under transaction/transition grants. These phantom series B subordinated units will vest in increments of 20%, 21%, 15%, 22% and 22%, respectively, in connection with the conversion of the First through Fifth Tranches of PNG s Series B Subordinated Units. Upon vesting, the phantom series B subordinated units will be payable one-for-one by PAA in Series A Subordinated Units or Common Units of PNG it receives upon conversion of PNG s Series B Subordinated Units. Any of these phantom series B subordinated units that have not vested as of December 31, 2018 will be automatically cancelled on such date.

Option Exercises and Units Vested

The following table sets forth certain information regarding the vesting of phantom units during the fiscal year ended December 31, 2011 with respect to our Named Executive Officers.

	Unit Awards	
Name	**Number of Units Acquired on Vesting (#)**	**Value Realized on Vesting ($)**
Greg L. Armstrong	60,000(1)	3,643,200(2)
	31,000(3)	721,370(3)
Harry N. Pefanis	40,000(1)	2,428,800(2)
	21,000(3)	488,670(3)
Al Swanson	11,666(1)	708,360(2)
	11,000(1)	670,230(4)
	10,500(3)	244,335(3)
W. David Duckett	25,000(1)	1,523,250(4)
John P. vonBerg	18,000(1)	1,092,960(2)

(1) Represents the gross number of phantom units that vested during the year ended December 31, 2011. The actual number of units delivered was net of income tax withholding.

(2) Consistent with the terms of our 2005 Long-Term Incentive Plan, the value realized upon vesting is computed by multiplying the closing market price ($60.72) of our common units on May 12, 2011 (the date preceding the vesting date) by the number of units that vested.

(3) Represents the gross number of transaction/transition grant awards that vested during the year ended December 31, 2011. These awards were settled by PAA in Common Units of PNG. The value realized is computed by multiplying the closing market price ($23.27) of PNG common units on May 5, 2011 (the date of vesting) by the number of transaction/transition grant awards that vested.

(4) Consistent with the terms of our 1998 Long-Term Incentive Plan, the value realized upon vesting is computed by multiplying the closing market price ($60.93) of our common units on May 13, 2011 (the date of vesting) by the number of units that vested.

Pension Benefits

We sponsor a 401(k) plan that is available to all U.S. employees, but we do not maintain a pension or defined benefit program.

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Nonqualified Deferred Compensation and Other Nonqualified Deferred Compensation Plans

We do not have a nonqualified deferred compensation plan or program for our officers or employees.

Potential Payments upon Termination or Change-in-Control

The following table sets forth potential amounts payable to the Named Executive Officers upon termination of employment under various circumstances, and as if terminated on December 31, 2011.

	By Reason of Death ($)	By Reason of Disability ($)	By Company without Cause ($)	By Executive with Good Reason ($)	In Connection with a Change In Control ($)
Greg L. Armstrong					
Salary and Bonus	7,250,000(1)	7,250,000(1)	7,250,000(1)	7,250,000(1)	10,875,000(2)
Equity Compensation	24,011,250(3)	24,011,250(3)	22,616,250(4)	22,035,000(4)	24,941,250(5)
Health Benefits	N/A	28,430(6)	28,430(6)	28,430(6)	28,430(6)
Tax Gross-up	N/A	N/A	N/A	N/A	597,411(7)
Class B Units	N/A	N/A	N/A	N/A	7,835,800(8)
Total	31,261,250	31,289,680	29,894,680	29,313,430	44,277,891
Harry N. Pefanis					
Salary and Bonus	6,800,000(1)	6,800,000(1)	6,800,000(1)	6,800,000(1)	10,200,000(2)
Equity Compensation	16,028,750(3)	16,028,750(3)	15,083,750(4)	14,690,000(4)	16,658,750(5)
Health Benefits	N/A	43,926(6)	43,926(6)	43,926(6)	43,926(6)
Tax Gross-up	N/A	N/A	N/A	N/A	805,172(7)
Class B Units	N/A	N/A	N/A	N/A	5,876,850(8)
Total	22,828,750	22,872,676	21,927,676	21,533,926	33,584,698
Al Swanson (9)					
Equity Compensation	8,406,157(3)	8,406,157(3)	2,473,825(4)	N/A	8,721,157(5)
Class B Units	N/A	N/A	N/A	N/A	1,958,950(8)
Total	8,406,157	8,406,157	2,473,825	N/A	10,680,107
W. David Duckett (9)					
Equity Compensation	9,181,250(3)	9,181,250(3)	3,672,500(4)	N/A	9,181,250(5)
Class B Units	N/A	N/A	N/A	N/A	3,330,215(8)
Total	9,181,250	9,181,250	3,672,500	N/A	12,511,465
John P. vonBerg (9)					
Equity Compensation	6,610,500(3)	6,610,500(3)	2,644,200(4)	N/A	6,610,500(5)
Class B Units	N/A	N/A	N/A	N/A	2,742,530(8)
Total	6,610,500	6,610,500	2,644,200	N/A	9,353,030

(1) The employment agreements between Plains All American GP LLC and Messrs. Armstrong and Pefanis provide that if (i) their employment with Plains All American GP LLC is terminated as a result of their death, (ii) they terminate their employment with Plains All American GP LLC (a) because of a disability (as defined in Section 409A of the Code) or (b) for good reason (as defined below), or (iii) Plains All American GP LLC terminates their employment without cause (as defined below), they are entitled to a lump-sum amount equal to the product of (1) the sum of their (a) highest annual base salary paid prior to their date of termination and (b) highest annual bonus paid or payable for any of the three years prior to the date of termination, and (2) the lesser of (i) two or (ii) the number of days remaining in the term of their employment agreement divided by 360. The amount provided in the table assumes for each executive a termination date of December 31, 2011, and also assumes a highest annual base salary of $375,000 and

highest annual bonus of $3,250,000 for Mr. Armstrong, and a highest annual base salary of $300,000 and highest annual bonus of $3,100,000 for Mr. Pefanis.

The employment agreements between Plains All American GP LLC and Messrs. Armstrong and Pefanis define cause as (i) willfully engaging in gross misconduct, or (ii) conviction of a felony involving moral turpitude. Notwithstanding, no act, or failure to act, on their part is willful unless done, or omitted to be done, not in good faith and without reasonable belief that such act or omission was in the best interest of Plains All American GP LLC or otherwise likely to result in no material injury to Plains All American GP LLC. However, neither Mr. Armstrong or Mr. Pefanis will be deemed to have been terminated for cause unless and until there is delivered to them a copy of a resolution of the board of directors of Plains All American GP LLC at a meeting held for that purpose (after reasonable notice and an opportunity to be heard), finding that Mr. Armstrong or Mr. Pefanis, as applicable, was guilty of the conduct described above, and specifying the basis for that finding. If Mr. Armstrong or Mr. Pefanis were terminated for cause, Plains All American GP LLC would be obligated to pay base salary through the date of termination, with no other payment obligations triggered by the termination under the employment agreement or other employment arrangement.

The employment agreements between Plains All American GP LLC and Messrs. Armstrong and Pefanis define good reason as the occurrence of any of the following circumstances: (i) removal by Plains All American GP LLC from, or failure to re-elect them to, the positions to which Messrs. Armstrong and Pefanis were appointed pursuant to their respective employment agreements, except in connection with their termination for cause (as defined above); (ii) (a) a reduction in their rate of base salary (other than in connection with across-the-board salary reductions for all executive officers of Plains All American GP LLC) unless such reduction reduces their base salary to less than 85% of their current base salary, (b) a material reduction in their fringe benefits, or (c) any other material failure by Plains All American GP LLC to comply with its obligations under their employment agreements to pay their annual salary and bonus, reimburse their business expenses, provide for their participation in certain employee benefit plans and arrangements, furnish them with suitable office space and support staff, or allow them no less than 15 business days of paid vacation annually; or (iii) the failure of Plains All American GP LLC to obtain the express assumption of the employment agreements by a successor entity (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of Plains All American GP LLC.

(2) Pursuant to their employment agreements, if Messrs. Armstrong and Pefanis terminate their employment with Plains All American GP LLC within three (3) months of a change in control (as defined below), they are entitled to a lump-sum payment in an amount equal to the product of (i) three and (ii) the sum of (a) their highest annual base salary previously paid to them and (b) their highest annual bonus paid or payable for any of the three years prior to the date of such termination. The amount provided in the table assumes a change in control and termination date of December 31, 2011, and also assumes a highest annual base salary of $375,000 and highest annual bonus of $3,250,000 for Mr. Armstrong, and a highest annual base salary of $300,000 and highest annual bonus of $3,100,000 for Mr. Pefanis.

For this purpose a change in control is currently defined in their employment agreements to mean (i) the acquisition by a person or group (other than Vulcan Energy or a wholly owned subsidiary thereof) of beneficial ownership, directly or indirectly, of 50% or more of the membership interest of Plains All American GP LLC or (ii) the owners of the membership interests of Plains All American GP LLC on June 30, 2001 ceasing to beneficially own, directly or indirectly, more than 50% of the membership interests of Plains All American GP LLC.

In August 2005, Vulcan Energy increased its interest in Plains All American GP LLC from approximately 44% to greater than 50%. The consummation of the transaction constituted a change in control under the employment agreements with Messrs. Armstrong and Pefanis. However, Messrs. Armstrong and Pefanis entered into agreements with Plains All American GP LLC waiving their rights to payments under their employment agreements in connection with the change in control, contingent on the execution and performance by Vulcan Energy of a voting agreement with Plains All American GP LLC that restricted certain of Vulcan s voting rights. The December 2010 sale by Vulcan Energy of its interest in our general

partner also constituted a change in control under the employment agreements and resulted in the termination of the voting agreement. Messrs. Armstrong and Pefanis executed new agreements waiving their rights to payments under their employment agreements with respect to the December 2010 transaction and voting agreement termination.

(3) The letters evidencing phantom unit grants to our Named Executive Officers between 2007 and 2010 provide that in the event of their death or disability (as defined below), all of their then outstanding phantom units and associated DERs will be deemed nonforfeitable, and (i) any unvested phantom units that had satisfied all of the vesting criteria as of the date of their termination but for the passage of time would vest on the next following distribution date and (ii) the remaining unvested outstanding phantom units will vest on the distribution date on which the vesting criteria is met. For this purpose disability means a physical or mental infirmity that impairs the ability substantially to perform duties for a period of eighteen (18) months or that the general partner otherwise determines constitutes a disability.

Assuming death or disability occurred on December 31, 2011, all phantom units and the associated DERs of our Named Executive Officers would have become nonforfeitable effective as of December 31, 2011, and vested on the February 2012 distribution date to the extent the vesting criteria had been satisfied (other than the passage of time) or, if the vesting criteria had not been satisfied, at the times described in the footnotes to the Outstanding Equity Awards at Fiscal Year-End table. For the 2007, 2009 and 2010 grants, any units not vested by May 2014, May 2015 and May 2016, respectively, would expire. That portion of the dollar value given that is attributable to PAA phantom units assumes that all performance thresholds will be timely achieved if deemed probable of occurrence as of December 31, 2011, and is based on the market value of PAA s common units on December 31, 2011 ($73.45 per unit) without discount for service period. If the performance thresholds were not deemed probable of occurrence as of December 31, 2011, the units are assumed to expire unvested in May 2015 or May 2016. At December 31, 2011, an annualized distribution level of $4.35 was deemed probable of occurrence. All outstanding grants were assumed to eventually vest as a result.

The transaction/transition grant agreements provide that in the event of death or disability (as defined above), any unvested phantom units and associated DERs shall be deemed nonforfeitable and shall vest or be cancelled at the times described in the footnotes to the Outstanding Equity Awards at Fiscal Year-End Table. As of December 31, 2011, vesting of all of the phantom common units and phantom series A subordinated units, and vesting of 20% of the phantom series B subordinated units, was deemed probable of occurrence. That portion of the dollar value given that is attributable to the transaction/transition grants is based on the market value of PNG s common units on December 31, 2011 ($18.75 per unit), without discount for service period.

(4) Pursuant to the phantom unit grants to our Named Executive Officers between 2007 and 2010, in the event their employment is terminated other than in connection with a change of control (as defined in Footnote 5 below) or by reason of death, disability (as defined in Footnote 3 above) or retirement, all of the phantom units and associated DERs (regardless of vesting) then outstanding under such phantom unit grants would automatically be forfeited as of the date of termination; provided, however, that if Plains All American GP LLC terminated their employment other than for cause (as defined in Footnote 5 below), any unvested phantom units that had satisfied all of the vesting criteria as of the date of their termination but for the passage of time would be deemed nonforfeitable and would vest on the next following distribution date. The dollar value amount provided assumes that our Named Executive Officers were terminated without cause on December 31, 2011. As a result, one-half of the outstanding 2007 phantom unit grants and one-third of the 2010 phantom unit grants held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg would be deemed nonforfeitable and would vest on the February 2012 distribution date. The remaining portion of the outstanding phantom units granted in 2007, 2009 and 2010 would be forfeited. That portion of the dollar value given that is attributable to PAA phantom units is based on the market value of PAA s common units on December 31, 2011 ($73.45 per unit), without discount for service period. In addition to the foregoing, under Canadian law, Mr. Duckett could have a claim for additional payment if inadequate notice were given for a termination without cause.

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Under the waiver signed in 2010 by Mr. Armstrong and Mr. Pefanis (see footnote 2 above), upon a termination of employment by the company without cause or by the executive for good reason (in each case as defined in the relevant employment agreement) all of the executive s outstanding awards under the 1998 and 2005 Long-Term Incentive Plans would immediately vest.

The transaction/transition grant agreements provide that in the event of termination without cause (as defined in Footnote 5 below), any unvested phantom common units and associated DERs shall be deemed nonforfeitable and shall be payable on the next following distribution date. That portion of the dollar value given that is attributable to the transaction/transition grants is based on the market value of PNG s common units on December 31, 2011 ($18.75 per unit), without discount for service period.

(5) The letters evidencing the phantom unit grants to our Named Executive Officers between 2007 and 2010, provide that in the event of a change in status (as defined below), all of the then outstanding phantom units and associated DERs will be deemed nonforfeitable, and such phantom units will vest in full (i.e., the phantom units will become payable in the form of one common unit per phantom unit) upon the next following distribution date. Assuming the change in status occurred on December 31, 2011, all outstanding phantom units and the associated DERs would have become nonforfeitable as of December 31, 2011, and such phantom units would vest on the February 2012 distribution date. That portion of the dollar value given that is attributable to PAA phantom units is based on the market value of PAA s common units on December 31, 2011 ($73.45 per unit), without discount for service period.

The transaction/transition grant agreements provide that in the event of a change in status (as defined below), all outstanding phantom units and tandem DERs shall be deemed nonforfeitable on such date, and such phantom units will be payable on the next following distribution date. Assuming a change in status occurred on December 31, 2011, all outstanding phantom units under the transaction/transition grant agreements would have been nonforfeitable and would have vested on the February 2012 distribution date. That portion of the dollar value given that is attributable to the transaction/transition grants is based on the market value of PNG s common units on December 31, 2011 ($18.75 per unit), without discount for service period.

The phrase change in status means, with respect to a Named Executive Officer, the occurrence, during the period beginning two and a half months prior to and ending one year following a change of control (as defined below), of any of the following: (A) the termination of employment by Plains All American GP LLC other than a termination for cause (as defined below), or (B) the termination of employment by the Named Executive Officer due to the occurrence, without the Named Executive Officer s written consent, of (i) any material diminution in the Named Executive Officer s authority, duties or responsibilities, (ii) any material reduction in the Named Executive Officer s base salary or (iii) any other action or inaction that would constitute a material breach of the agreement by Plains All American GP LLC.

The phrase change of control means, and is deemed to have occurred upon the occurrence of, one or more of the following events: (i) Plains All American GP LLC ceasing to be the general partner of our general partner; (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 our partnership or Plains All American GP LLC to any person and/or its affiliates, other than to us or Plains All American GP LLC, including any employee benefit plan thereof; (iii) the consolidation, reorganization, merger, or any other similar transaction involving (A) a person other than us or Plains All American GP LLC and (B) us, Plains All American GP LLC or both; (iv) the persons who own membership interests in Plains All American GP LLC as of the grant date ceasing to beneficially own, directly or indirectly, more than 50% of the membership interests of Plains All American GP LLC; 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 Plains All American GP LLC. Notwithstanding the definition of change of control, no change of control is deemed to have occurred in connection with a restructuring or reorganization related to the securitization and sale to the public of direct or indirect equity interests in the general partner if (x) Plains All American GP LLC retains direct or indirect control over the general partner and (y) the

current members of Plains All American GP LLC continue to own more than 50% of the member interest in Plains All American GP LLC. The term cause means (i) the failure to perform a job function in accordance with standards described in writing, or (ii) the violation of Plains All American GP LLC s Code of Business Conduct (unless waived in accordance with the terms thereof), in each case, with the specific failure or violation described in writing.

(6) Pursuant to their employment agreements with Plains All American GP LLC, if Messrs. Armstrong or Pefanis are terminated other than (i) for cause (as defined in Footnote 1 above), (ii) by reason of death or (iii) by resignation (unless such resignation is due to a disability or for good reason (each as defined in Footnote 1 above)), then they are entitled to continue to participate, for a period which is the lesser of two years from the date of termination or the remaining term of the employment agreement, in such health and accident plans or arrangements as are made available by Plains All American GP LLC to its executive officers generally. The amounts provided in the table assume a termination date of December 31, 2011.

(7) Pursuant to their employment agreements, Messrs. Armstrong and Pefanis will be reimbursed for any excise tax due under Section 4999 of the Code as a result of compensation (parachute) payments made under their respective employment agreements. The values provided for this benefit assume that Messrs. Armstrong and Pefanis were terminated in connection with a change in control effective as of December 31, 2011.

(8) Pursuant to the Class B Restricted Units Agreements, upon the occurrence of a Change in Control, any earned Class B units (and any Class B units that will become earned in less than 180 days) become vested units and, to the extent any Class B units remain unearned, an incremental 25% of the number of Class B units originally granted becomes vested. As of December 31, 2011, 50% of the Class B units held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg had been earned. Assuming a Change in Control on December 31, 2011, 75% of the Class B units held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg would become vested.

The value of such Class B units as reflected in the table is derived in accordance with FASB ASC Topic 718. Change in Control means the determination by the Board that one of the following events has occurred: (i) Plains All American GP LLC ceases to retain direct or indirect control over the Partnership; (ii) the owners of Plains All American GP LLC as of the respective grant date of the Class B units (the Grant Date) and their affiliates (the Owner Affiliates) cease to own directly or indirectly at least 50% of its member interest; (iii) a person or group (as such terms are used in Sections 13(d) and 14(d) of the Exchange Act) becomes after the Grant Date the beneficial owner (as defined in Rules 13(d)-3 and 13(d)-5 under the Exchange Act), directly or indirectly, of more than 50% of the member interest of Plains All American GP LLC; or (iv) a transfer, sale, exchange or other disposition in a single transaction or series of transactions (whether by merger or otherwise) of all or substantially all of the assets of the Plains AAP, L.P. or the Partnership to one or more persons who are not Affiliates of Plains AAP, L.P., other than a transaction in which the Owner Affiliates become the beneficial owners, directly or indirectly, of more than 50% of the voting power of such person or persons immediately following such transaction.

(9) If Messrs. Swanson, Duckett or vonBerg were terminated for cause, Plains All American GP LLC would be obligated to pay base salary through the date of termination, with no other payment obligation triggered by the termination under any employment arrangement.

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Confidentiality, Non-Compete and Non-Solicitation Arrangements

Pursuant to his employment agreement, Mr. Armstrong has agreed to maintain the confidentiality of PAA information for a period of five years after the termination of his employment. Mr. Pefanis has agreed to a similar restriction for a period of one year following the termination of his employment. Mr. Duckett has agreed to maintain confidentiality following termination of his employment for a period of two years with respect to customer lists. He has also agreed not to compete in a specified geographic area for a period of two years after termination of his employment. Mr. vonBerg has agreed to maintain confidentiality and not to solicit customers for a period of one year following termination of his employment.

Compensation of Directors

The following table sets forth a summary of the compensation paid to each person who served as a non-employee director of Plains All American GP LLC in 2011:

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($) (1)	Total ($)
Everardo Goyanes	75,000	151,000	226,000
Gary R. Petersen	45,000	75,500	120,500
John T. Raymond	45,000	358,500	403,500
Robert V. Sinnott	47,000	75,500	122,500
Vicky Sutil (2)	45,000	n/a	45,000
J. Taft Symonds	62,000	151,000	213,000
Christopher M. Temple	60,000	151,000	211,000

(1) The dollar value of LTIPs granted during 2011 is based on the grant date fair value computed in accordance with FASB ASC Topic 718. In connection with the August 2011 vesting of director LTIP awards, Messrs. Goyanes, Symonds and Temple each were granted 2,500 units, Messrs. Petersen and Sinnott each were granted 1,250 units and Mr. Raymond was granted 625 units by virtue of the automatic re-grant feature of the vested awards. Upon vesting of the director LTIP awards in August 2011 (other than the incremental audit committee awards), a cash payment of $76,263 was made to Oxy as directed by Ms. Sutil. Such cash payment was based on the unit value of Mr. Sinnott s award on the previous year s vesting date. In addition to the automatic regrant in August, Mr. Raymond received an initial grant of 5,000 LTIPs in February 2011. As of December 31, 2011, the number of outstanding LTIPs held by our directors was as follows: Goyanes - 10,000 ; Petersen - 5,000; Raymond - 5,000; Sinnott - 5,000; Symonds - 10,000; and Temple - 10,000.

(2) Ms. Sutil s compensation is assigned to Oxy.

Each director of Plains All American GP LLC who is not an employee of Plains All American GP LLC 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). 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. During 2011, Messrs. Sinnott, Goyanes and Symonds served as chairmen of the compensation, audit and governance committees, respectively.

Our non-employee directors receive LTIP awards or cash equivalent awards as part of their compensation. The LTIP awards vest annually in 25% increments over a four-year period and have an automatic re-grant feature such that as they vest, an equivalent amount is granted. The awards have associated distribution equivalent rights that are payable quarterly. The three non-employee directors who serve on the audit committee (Messrs. Goyanes, Symonds and Temple) each have outstanding a grant of 10,000 units (vesting 2,500 units per year). Messrs.

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Petersen, Raymond and Sinnott each have outstanding a grant of 5,000 units (vesting 1,250 units per year). Upon vesting of the director LTIPs (other than the incremental audit committee awards), a cash payment will be made to Oxy as directed by the Oxy designee. Such cash payment is based on the unit value of Mr. Sinnott s award on the previous year s vesting date.

All LTIP awards held by a director vest in full upon the next following distribution date after the death or disability (as determined in good faith by the board) of the director. For audit committee grants, the awards 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 of directors or is not reelected to the board of directors, unless such removal or failure to reelect is for good cause, as defined in the letter granting the units.

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 direct and indirect costs of services provided to us, incurred on our behalf, including the costs of employee, officer and director compensation (other than expenses related to the Class B units of Plains AAP, L.P.) and benefits allocable to us, as well as all other expenses necessary or appropriate to the conduct of our business, allocable to us. We record these costs on the accrual basis in the period in which our general partner incurs them. 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.

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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 15, 2012.

Name of Beneficial Owner	Common Units	Percentage of Common Units
Richard Kayne/Kayne Anderson Capital Advisors, L.P.	7,613,685(1)	4.9%
Greg L. Armstrong	500,010(2)	(3)
Harry N. Pefanis	307,798(2)	(3)
Dave Duckett	134,791(2)	(3)
John P. vonBerg	64,903(2)	(3)
Al Swanson	47,999(2)	(3)
Everardo Goyanes	31,700(2)	(3)
Gary R. Petersen	6,250(2)	(3)
John T. Raymond	699,704(2)	(3)
Robert V. Sinnott	61,905(2)(4)	(3)
Vicky Sutil		
J. Taft Symonds	37,300(2)	(3)
Chris Temple	3,125(2)	(3)
All directors and executive officers as a group (17 persons)	2,126,319(2)(5)	1.4%

(1) 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 7,344,668 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 269,017 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, 3rd Floor, Los Angeles, California 90067.

(2) Does not include unvested phantom units granted under our Long-Term Incentive Plans, none of which will vest within 60 days of the date hereof. See Item 11. Executive Compensation Outstanding Equity Awards at Fiscal Year-End and Director Compensation.

(3) Less than one percent.

(4) Pursuant to the GP LLC Agreement, Mr. Sinnott has been designated as 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 the interests owned by KAFU Holdings, L.P. or its affiliates, beyond his pecuniary interest therein, if any. Mr. Sinnott has a non-controlling ownership interest in KACALP, which is the general partner of KAFU Holdings, L.P. KACALP is entitled to a percentage of the profits earned by the funds invested in KAFU Holdings, L.P. The address for KAFU Holdings, L.P. is 1800 Avenue of the Stars, 3rd Floor, Los Angeles, California 90067.

(5) As of February 15, 2012, no units were pledged by directors or Named Executive Officers. Certain of the directors and Named Executive Officers hold units in marginable broker s accounts, but none of the units were margined as of February 15, 2012.

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Beneficial Ownership of General Partner Interest

Plains AAP, L.P. owns all of our incentive distribution rights and, through its 100% member interest in PAA GP LLC, our 2% general partner interest. 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 of Owner and Address (in the case of Owners of more than 5%)	Percentage Ownership of Plains AAP, L.P. (1)
Oxy Holding Company (Pipeline), Inc. 10889 Wilshire Boulevard Los Angeles, CA 90024	35.0%
EMG Investment, LLC 1401 McKinney, Suite 1025 Houston, TX 77101	25.0%
KAFU Holdings, L.P. and Affiliates (2) 1800 Avenue of the Stars, 3rd Floor Los Angeles, CA 90067	20.8%
KA First Reserve XII, LLC 600 Travis, Suite 6000 Houston, TX 77002	5.9%
PAA Management, L.P. (3)	4.6%
Strome PAA, L.P.	3.7%
Windy, L.L.C.	3.0%
Lynx Holdings I, LLC	1.4%
Various Individual Investors	0.6%

(1) Plains AAP, L.P. owns a 100% member interest in PAA GP LLC, which owns our 2% general partner interest. Plains AAP, L.P. has pledged its member interest, as well as its interest in our incentive distribution rights, as security for its obligations under the Credit Agreement dated as of January 3, 2008 among Plains AAP, L.P., Citibank, N.A. and the lenders party thereto (the Plains AAP Credit Agreement). A default by Plains AAP, L.P. under the Plains AAP Credit Agreement could result in a change in control of our general partner. Certain members of management own a profits interest in Plains AAP, L.P. in the form of Class B units.

(2) Mr. Sinnott disclaims any deemed beneficial ownership of the interests owned by KAFU Holdings, L.P. beyond his pecuniary interest therein, if any. Mr. Sinnott has a non-controlling ownership interest in KACALP, which is the general partner of KAFU Holdings, L.P. KACALP is entitled to a percentage of the profits earned by the funds invested in KAFU Holdings, L.P.

(3) PAA Management, L.P. is owned entirely by certain current and former members of senior management, including Messrs. Armstrong (approximately 25%), Pefanis (approximately 14%), Duckett (approximately 6%), vonBerg (approximately 4%) and Swanson (approximately 5%). Other than Mr. Armstrong, no directors own any interest in PAA Management, L.P. Executive officers as a group own approximately 70% 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.

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Equity Compensation Plan Information

The following table sets forth certain information with respect to our equity compensation plans as of December 31, 2011. For a description of these plans, see Item 13. Certain Relationships and Related Transactions, and Director Independence Equity-Based Long-Term Incentive Plans.

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	382,667(1)	N/A(2)	392,127(1)(3)
2005 Long Term Incentive Plan	1,340,336(4)	N/A(2)	696,373(3)(4)
Equity compensation plans not approved by unitholders:			
1998 Long Term Incentive Plan	(1)(5)	N/A(2)	(6)
PPX Successor LTIP	347,750(7)	N/A(2)	620,294(3)(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, 2011, we have issued approximately 550,734 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 unless such LTIPs are by their terms payable only in cash. 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, 2005 LTIP and PPX Successor 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), (4) and (7), 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 unless such LTIPs are by their terms payable only in cash. 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 350,528 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) In connection with the Pacific merger, under applicable stock exchange rules, we carried over the available units under the Pacific LTIP (applying the conversion ratio of 0.77 PAA units for each Pacific unit). In that regard, we have adopted the Plains All American PPX Successor Long-Term Incentive Plan (the PPX Successor LTIP). Potential awards under such plan include options and phantom units (with or without tandem DERs). The provisions of such plan are substantially the

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same as the 2005 LTIP, except that awards under the PPX Successor LTIP may only be made to employees who were working for Pacific at the time of the merger or to employees hired after the date of the Pacific acquisition. The number of units presented in column (a) assumes that all outstanding grants will be satisfied by the issuance of new units upon vesting unless such LTIPs are by their terms payable only in cash. 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).

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

For a discussion of director independence, see Item 10. Directors and Executive Officers of Our General Partner and Corporate Governance.

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, Plains Midstream Canada). We do not pay our general partner a management fee, but we do reimburse our general partner for all expenses incurred on our behalf (other than expenses related to the Class B units of Plains AAP, L.P.). Total costs reimbursed by us to our general partner for the year ended December 31, 2011 were approximately $419 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. In connection with the Pacific, Rainbow and PNGS acquisitions, our general partner agreed to a temporary reduction in the amount of incentive distributions otherwise payable to it. These reductions were completed with payment of the November 2011 distribution. Effective upon closing of the BP NGL acquisition, which is anticipated to occur in the second quarter of 2012, our general partner has agreed to a reduction in incentive distributions equal to $3,750,000 per quarter for eight quarters beginning with the first distribution paid following closing. Thereafter, the general partner has agreed to an ongoing reduction of $2.5 million per quarter.

The following table illustrates the allocation of aggregate distributions at different per-unit levels, excluding the effect of the incentive distribution reductions (dollars in thousands):

Annual LP Distribution Per Unit	Distribution to LP Unitholders(1)	Distribution to GP(1)(2)	Total Distribution(1)(2)	GP % of Total Distribution
$ 1.80	$ 279,720	$ 5,709	$ 285,429	2%
$ 1.98	$ 307,692	$ 10,645	$ 318,337	3%
$ 2.70	$ 419,580	$ 47,941	$ 467,521	10%
$ 4.10	$ 637,140	$ 265,501	$ 902,641	29%
$ 4.20	$ 652,680	$ 281,041	$ 933,721	30%

$ 4.30	$ 668,220	$ 296,581	$ 964,801	31%

(1) Assumes 155,400,000 units outstanding. The actual number of units outstanding as of December 31, 2011 was 155,376,937. An increase in the number of units outstanding would increase both the distribution to unitholders and the distribution to the general partner for any given level of distribution per unit.

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

Equity-Based 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 Plains All American GP LLC 2005 Long-Term Incentive Plan (the 2005 LTIP) for employees and directors of our general partner and its affiliates who perform services for us, and the PPX Successor LTIP for former Pacific employees and employees hired after the date of the Pacific merger (together with the 1998 LTIP and 2005 LTIP, the Plans). Awards contemplated by the Plans include phantom units (referred to as restricted units in the 1998 LTIP), distribution equivalent rights (DERs) and unit options. As amended, the 1998 LTIP authorizes the grant of awards covering an aggregate of 1,425,000 common units deliverable upon vesting or exercise (as applicable) of such awards. The 2005 LTIP authorizes the grant of awards covering an aggregate of 3,000,000 common units deliverable upon vesting or exercise (as applicable) of such awards. The PPX Successor LTIP authorizes the grant of awards covering an aggregate of 999,809 common units deliverable upon vesting or exercise (as applicable) of such awards. Our general partner s board of directors has the right to alter or amend 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

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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 newly issued common units, common units acquired by our general partner in the open market or in private transactions, common units acquired by us from any other person, 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).

As of December 31, 2011, grants of approximately 419,767; 1,625,270; and 647,299 unvested phantom units were outstanding under the 1998 LTIP, 2005 LTIP and PPX Successor LTIP, respectively, and approximately 392,127; 696,373; and 620,294 remained available for future grant, respectively. The compensation committee or 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 board of directors shall determine, including 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.

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.

Unit Options. Although the Plans currently permit the grant of options covering common units, no options have been granted under the Plans 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.

Class B Units of Plains AAP, L.P.

In August 2007, the owners of Plains AAP, L.P. authorized the creation and issuance of up to 200,000 Class B units of Plains AAP, L.P. and authorized the compensation committee of Plains All American GP LLC to issue grants of Class B units to create long-term incentives for our management. The entire economic burden of the Class B units, which are equity classified, is borne solely by Plains AAP, L.P. and does not impact our cash or units outstanding. Therefore, we recognize the grant date fair value of the Class B units as compensation expense over the service period. The expense is also reflected as a capital contribution, and thus results in a corresponding credit to Partners Capital in our Consolidated Financial Statements. The expense and capital contribution for the twelve months ended December 31, 2011 was approximately $9.0 million. We will not be obligated to reimburse Plains AAP, L.P. for such costs and any distributions made on the Class B units will not reduce the amount of cash available for distribution to our unitholders. Each Class B unit represents a profits interest in Plains AAP, L.P., which entitles the holder to participate in future profits and losses from operations, current distributions from operations, and an interest in future appreciation or depreciation in Plains AAP, L.P. s asset values. As of December 31, 2011, 183,500 Class B units were issued and outstanding.

The outstanding Class B units are subject to restrictions on transfer and generally become earned (entitled to participate in distributions) in percentage increments when the annualized quarterly distributions on our common units equal or exceed certain thresholds. Upon achievement of these performance thresholds (or, in some cases, within six months thereafter), the Class B units will be entitled to their proportionate share of all quarterly cash distributions made by Plains AAP, L.P. in excess of $11 million per quarter (as adjusted for debt service costs and excluding special distributions funded by debt). Assuming all authorized Class B units are issued, the maximum participation would be 8% of the amount in excess of $11 million per quarter, as adjusted. As of February 14, 2012, approximately 71% of the outstanding Class B units had been earned or will be earned within 180 days. The remaining Class B units will be earned upon, or within 180 days after, payment of annualized quarterly distributions ranging from $4.20 to $4.80 per unit.

To encourage retention following achievement of these performance benchmarks, Plains AAP, L.P. retained a call right to purchase any earned Class B units at a discount to fair market value that is exercisable upon the termination of a holder s employment with Plains All American GP LLC and its affiliates for any reason prior to January 1, 2016 (January 1, 2017 for Class B units granted in 2010 and January 1, 2020 for Class B units granted in 2011), other than a termination of employment by the employee for good reason or by Plains All American GP LLC other than for cause (as defined). Upon the occurrence of a change of control (as defined), all earned units, plus 25% of any unearned units, will vest (no longer be subject to Plains AAP, L.P. s call right). All earned

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Class B units will also vest if they remain outstanding as of January 1, 2016 (January 1, 2017 for Class B units granted in 2010 and January 1, 2020 for Class B units granted in 2011) or Plains AAP, L.P. elects not to timely exercise its call right.

Transactions with Related Persons

Vulcan Energy

In December 2010, Vulcan Energy sold its 50.1% interest in our general partner. Substantially all of the interest was acquired by existing owners of PAA s general partner or their affiliates. Purchasers included a subsidiary of Occidental Petroleum Corporation (Oxy); a fund affiliated with The Energy & Minerals Group (EMG), which is also an affiliate of Lynx Holdings; funds associated with Kayne Anderson and First Reserve; and various other investors. As of December 31, 2011, Vulcan Energy and its affiliates owned less than 5% of our outstanding limited partner units.

Voting Agreements. In August 2005, in connection with an increase in Vulcan Energy s ownership interest in our general partner, Vulcan Energy entered into a voting agreement that restricted its ability to unilaterally elect or remove the independent directors serving on our audit committee. Lynx Holdings I, LLC, also agreed to restrict certain of its voting rights with respect to its membership interest in GP LLC. 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 voting rights agreements were terminated in December 2010 in connection with the sale by Vulcan Energy of its 50.1% interest in our general partner. Vulcan Energy has agreed that prior to the earlier of December 23, 2015 and the date, if any, of certain changes in our senior-most management, it will not vote any of its limited partner interests in favor of any proposal to remove GP LLC as our general partner. See Item 10. Directors and Executive Officers of Our General Partner and Corporate Governance Partnership Management and Governance.

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 provided administrative services to Vulcan Energy for consideration of an annual fee of $1 million, plus certain expenses. The Services Agreement was terminated in December 2010 in connection with the sale by Vulcan Energy of its 50.1% interest in our general partner. However, we continued to provide transition services and assistance to Vulcan Energy until June 2011 for consideration of a $1 million fee.

Indemnification Arrangement. In 2001, in connection with the transfer of interests in our general partner, Vulcan Energy (as successor in interest to the owner of our former general partner) agreed to indemnify us for (i) any claims relating to securities laws or regulations in connection with the upstream or midstream businesses, based on acts or omissions, or alleged acts or omissions, occurring on or prior to June 8, 2001, or (ii) any claims relating to the operation of the upstream business, whenever arising. In addition, we agreed to indemnify Vulcan Energy for any claims relating to the operation of the midstream business, whenever arising.

Other. In addition to those relationships described above, we have engaged in other transactions with affiliates of Vulcan Energy. See Natural Gas Storage Investment.

Natural Gas Storage Investment

In September 2005, we and Vulcan Gas Storage LLC, a subsidiary of Vulcan LLC, an investment arm of Paul G. Allen, formed PAA/Vulcan Gas Storage, LLC to acquire ECI (now known as PAA Natural Gas Storage, LLC or PNGS), an indirect subsidiary of Sempra Energy, for approximately $250 million. We and Vulcan Gas Storage each made an initial cash investment of approximately $113 million and Bluewater Natural Gas Holdings, LLC, a subsidiary of PAA/Vulcan, entered into a $90 million credit facility contemporaneously with closing.

From September 2005 until September 3, 2009, we owned 50% of PAA/Vulcan and Vulcan Gas Storage LLC owned the other 50%. Giving effect to all contributions and distributions made during the period from January 1, 2007 through September 3, 2009, we and Vulcan Gas Storage each made a net contribution of $39 million. Such contributions and distributions did not result in an increase or decrease to our ownership interest.

On September 3, 2009, one of our subsidiaries acquired the remaining 50% interest in PAA/Vulcan from Vulcan Gas Storage LLC, which resulted in our ownership of a 100% interest in PNGS. The purchase price for the transaction consisted of $90 million in cash paid at closing, 1,907,305 common units issued to Vulcan Gas Storage at closing, and up to $40 million of deferred/contingent cash consideration. The deferred/contingent consideration is payable in cash in two installments of $20 million each upon achievement of certain performance milestones and events expected to occur over the next several years. The first of these installments was paid in May 2010. At closing of the acquisition, we repaid all of PNGS s outstanding debt. Mr. Temple had a profits interest in Vulcan Gas Storage from September 2008 until December 2009. The Board of Directors appointed a conflicts committee in connection with this transaction. After engaging in a process of review and deliberation, the conflicts committee determined that the transaction was fair and reasonable. See Review, Approval or Ratification of Transactions with Related Persons below.

PAA Natural Gas Storage, L.P.

PNG IPO. On May 5, 2010, PNG completed its IPO of 13,478,000 common units representing limited partner interests. The common units offered represented approximately 23% of the outstanding equity of PNG. We retained the remaining 77% equity interest in PNG.

Prior to the PNG IPO, we owned 100% of the natural gas storage business of PNG s predecessor, PNGS. Immediately prior to the closing of the PNG IPO, we contributed 100% of the equity interests in PNGS and its subsidiaries to PNG in exchange for approximately 18.1 million common units, approximately 13.9 million series A subordinated units, 11.5 million series B subordinated units and a 2% general partner interest and incentive distribution rights. In August 2010, the capital structure of PNG was modified to reduce the number of series A subordinated units by 2 million and increase the number of series B subordinated units by the same amount. As of December 31, 2011, we owned approximately 28.2 million common units, approximately 11.9 million series A subordinated units and 13.5 million series B subordinated units of PNG.

PNG Common Unit Private Placement. In February 2011, in connection with the Southern Pines acquisition, PNG completed a private placement of approximately 17.4 million PNG common units for net proceeds of approximately $370 million. Investors included funds managed by Kayne Anderson Capital Advisors and various third-party investors. In addition, we purchased approximately 10.2 million PNG common units for a total of approximately $230 million, including our proportionate 2% general partner contribution. As a result of these transactions, our aggregate ownership interest in PNG decreased to approximately 64% from 77%.

We also provided debt financing to PNG in the form of a $200 million three-year senior unsecured loan that bears interest at 5.25% and have provided additional support for certain normal course trade payables.

Omnibus Agreement. In conjunction with PNG s IPO, we entered into an omnibus agreement with PNG, pursuant to which we agreed upon certain aspects of our relationship with PNG, including, among other things (i) the provision by our general partner to PNG of certain general and administrative services and PNG s agreement to reimburse our general partner for such services, (ii) the provision by our general partner of such personnel as may be necessary to operate and manage PNG s business, and PNG s agreement to reimburse our general partner for the expenses associated with such personnel, (iii) certain indemnification obligations, and (iv) PNG s use of the name PAA and related marks. Under this agreement, we indemnify PNG for certain environmental liabilities, tax matters, and title or permitting defects generally for a period of three years after the closing of PNG s IPO. The environmental indemnifications are subject to a cap of $15 million and require PNG to pay the first $250,000 of costs incurred. In addition, PNG has indemnified us from any losses, costs or damages incurred by us or our general partner that are attributable to the ownership and operation of PNG s assets following the closing of the IPO.

Tax Sharing Agreement. In conjunction with PNG s IPO, we entered into a tax sharing agreement with PNG, pursuant to which we and PNG agreed on the method of allocation among us and our subsidiaries (other than PNG and its subsidiaries), on the one hand, and PNG and its subsidiaries on the other, of the responsibilities, liabilities and benefits relating to any taxes for which a combined return is filed for taxable periods including or beginning on May 5, 2010.

Other

EMG Investment, LLC has a 25% general partner interest in, and Mr. Raymond sits on the board of, High Sierra Energy GP, LLC, the general partner of High Sierra Energy LP (High Sierra). We recognized crude oil sales and transportation revenues and purchased petroleum products from High Sierra and its affiliates during 2011. For the year ended December 31, 2011, these revenues and purchases and related costs totaled $3 million and $14 million, respectively. These transactions were conducted at posted tariff rates or prices that we believe approximate market. Mr. Raymond is not an officer of High Sierra and does not participate in operational decision making.

During 2011, 2010 and 2009, we purchased approximately $3.8 million, $2.7 million and $2.2 million, respectively, of oil from companies owned and controlled by funds managed by KACALP. We pay the same amount per barrel to these companies that we pay to other producers in the area.

During 2011, 2010 and 2009, we recognized sales and transportation and storage revenues of approximately $2.6 billion, $2.2 billion and $0.2 billion, respectively, from companies affiliated with Oxy. During 2011, 2010 and 2009, we also purchased approximately $0.4 billion, $0.2 billion and $0.2 billion, respectively, of petroleum products from companies affiliated with Oxy. These transactions were conducted at posted tariff rates or prices that we believe approximate market.

An employee in our marketing department is the son of Phil Kramer, one of our executive officers. His total compensation for 2011 (which amount includes the grant date fair value of LTIPs awarded to him on terms consistent with all eligible employees) was approximately $173,000.

Review, Approval or Ratification of Transactions with Related Persons

Pursuant to our Governance Guidelines, a director is expected to bring to the attention of the CEO or the board any conflict or potential conflict of interest that may arise between the director or any affiliate of the director, on the one hand, and the Partnership

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or GP LLC on the other. The resolution of any such conflict or potential conflict should, at the discretion of the board in light of the circumstances, be determined by a majority of the disinterested directors.

If a conflict or potential conflict of interest arises between the Partnership and GP LLC, the resolution of any such conflict or potential conflict should be addressed by the board in accordance with the provisions of the Partnership Agreement. At the discretion of the board in light of the circumstances, the resolution may be determined by the board in its entirety or by a conflicts committee meeting the definitional requirements for such a committee under the Partnership Agreement. Such resolution may include resolution of any derivative conflicts created by an executive officer s ownership of interests in GP LLC or a director s appointment by an owner of GP LLC.

Pursuant to our Code of Business Conduct, any executive officer must avoid conflicts of interest unless approved by the board of directors.

In the case of any sale of equity by the Partnership in which an owner or affiliate of an owner of our general partner participates, our practice is to obtain general approval of the full board for the transaction. The board typically delegates authority to set the specific terms to a pricing committee, consisting of the CEO and one independent director. Actions by the pricing committee require unanimous approval.

Item 14. ***Principal Accountant Fees and Services***

The following table details the aggregate fees billed for professional services rendered by our independent auditor for services provided to us and to our consolidated subsidiaries (in millions):

	Year Ended December 31, 2011		Year Ended December 31, 2010	
Audit fees(1)	$	3.6	$	3.4
Audit-related fees(2)		0.1		0.1
Tax fees(3)		1.0		1.5
All other fees(4)				1.2
Total	$	4.7	$	6.2

(1) Audit fees include those related to (a) our annual audit (including internal control evaluation and reporting); (b) the annual audit of PNG; (c) the audit of certain joint ventures of which we are the operator, and (d) work performed on our registration of publicly held debt and equity, including fees associated with work performed in conjunction with the initial public offering of PNG.

(2) Audit-related fees primarily relate to audits of our benefit plans.

(3) Tax fees are related to tax processing as well as the preparation of Forms K-1 for our unitholders and international tax planning work associated with the restructuring of our Canadian investment.

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

Pre-Approval Policy

As discussed above, we have an audit committee that reviews our external financial reporting, engages our independent auditors and reviews the adequacy of our internal accounting controls. Our consolidated subsidiary, PNG, also has an audit committee that performs similar functions on PNG s behalf. All services provided by our independent auditor are subject to pre-approval by our audit committee or the audit committee of PNG (for services provided to PNG). The audit committees have instituted policies that describe certain pre-approved non-audit services. We believe that the descriptions of services are 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 committees are informed of each engagement of the independent auditor to provide services under the respective policy. All services provided by our independent auditor during the years ended December 31, 2011 and 2010 were approved in advance by the applicable audit committee.

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PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) (1) *Financial Statements*

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

(2) *Financial Statement Schedules*

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

(3) *Exhibits*

The exhibits listed on the accompanying Exhibit Index are filed or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

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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:	PAA GP LLC, *its general partner*
	By:	Plains AAP, L.P., *its sole member*
	By:	PLAINS ALL AMERICAN GP LLC, *its general partner*
	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)***
February 27, 2012		
	By:	/s/ AL SWANSON **Al Swanson,** ***Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)***
February 27, 2012		

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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)	February 27, 2012
/s/ HARRY N. PEFANIS Harry N. Pefanis	President and Chief Operating Officer of Plains All American GP LLC	February 27, 2012
/s/ AL SWANSON Al Swanson	Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)	February 27, 2012
/s/ CHRIS HERBOLD Chris Herbold	Vice President Accounting and Chief Accounting Officer of Plains All American GP LLC (Principal Accounting Officer)	February 27, 2012
/s/ EVERARDO GOYANES Everardo Goyanes	Director of Plains All American GP LLC	February 27, 2012
/s/ GARY R. PETERSEN Gary R. Petersen	Director of Plains All American GP LLC	February 27, 2012
/s/ JOHN T. RAYMOND John T. Raymond	Director of Plains All American GP LLC	February 27, 2012
/s/ ROBERT V. SINNOTT Robert V. Sinnott	Director of Plains All American GP LLC	February 27, 2012
/s/ VICKY SUTIL Vicky Sutil	Director of Plains All American GP LLC	February 27, 2012
/s/ J. TAFT SYMONDS J. Taft Symonds	Director of Plains All American GP LLC	February 27, 2012
/s/ CHRISTOPHER M. TEMPLE Christopher M. Temple	Director of Plains All American GP LLC	February 27, 2012

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS

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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 issued 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, 2011.

The effectiveness of the Partnership s internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on Page F-3.

/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/ AL SWANSON
Al Swanson
Executive Vice President and Chief Financial Officer of Plains All American GP LLC
(Principal Financial Officer)

February 27, 2012

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.:

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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Partnership s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide 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.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Houston, Texas
February 27, 2012

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in millions, except units)

	December 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 26	$ 36
Restricted cash		20
Trade accounts receivable and other receivables, net	3,190	2,746
Inventory	978	1,491
Other current assets	157	88
Total current assets	4,351	4,381
PROPERTY AND EQUIPMENT	9,029	7,814
Accumulated depreciation	(1,289)	(1,123)
	7,740	6,691
OTHER ASSETS		
Goodwill	1,854	1,376
Linefill and base gas	564	519
Long-term inventory	135	154
Investments in unconsolidated entities	191	200
Other, net	546	382
Total assets	$ 15,381	$ 13,703
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 3,599	$ 2,738
Short-term debt	679	1,326
Other current liabilities	233	151
Total current liabilities	4,511	4,215
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discount of $13 and $12, respectively	4,262	4,363
Long-term debt under credit facilities and other	258	268
Other long-term liabilities and deferred credits	376	284