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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FORM 10-K—2011 ANNUAL REPORT
Table of Contents

		Page
	PART I	3
Items 1 and 2.	Business and Properties	3
Item 1A.	Risk Factors	38
Item 1B.	Unresolved Staff Comments	53
Item 3.	Legal Proceedings	53
Item 4.	Mine Safety Disclosures	55
	PART II	56
Item 5.	Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities	56
Item 6.	Selected Financial Data	58
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	59
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	83
Item 8.	Financial Statements and Supplementary Data	84
Item 9.	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	84
Item 9A.	Controls and Procedures	85
Item 9B.	Other Information	85
	PART III	86
Item 10.	Directors and Executive Officers of Our General Partner and Corporate Governance	86
Item 11.	Executive Compensation	96
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters	115
Item 13.	Certain Relationships and Related Transactions, and Director Independence	118
Item 14.	Principal Accountant Fees and Services	122
	PART IV	123
Item 15.	Exhibits and Financial Statement Schedules	123

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 statements 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

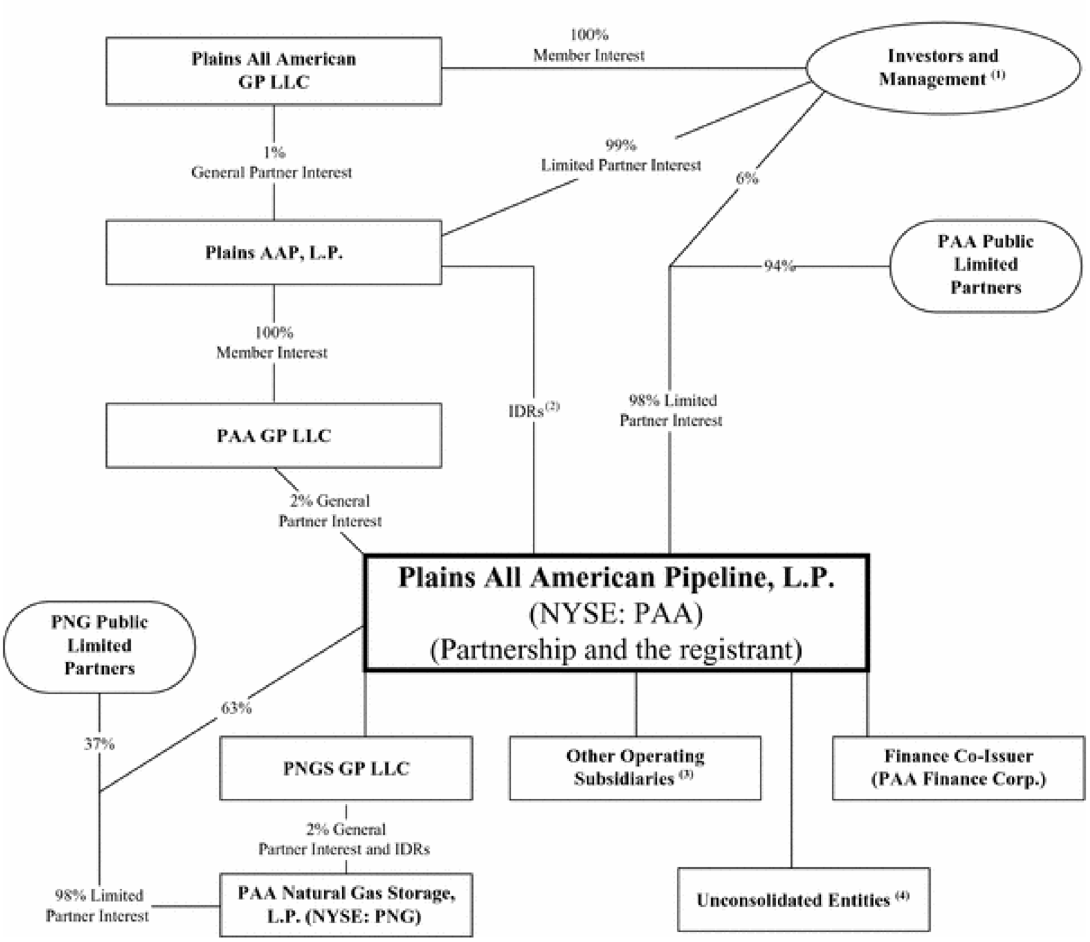
We were formed as a master limited partnership to acquire and operate the midstream crude oil businesses and assets of a predecessor entity and completed our initial public offering in 1998. Our 2% general partner interest is held by PAA GP LLC, a Delaware limited liability company, whose sole member 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.).

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

Partnership Structure


Plains All American GP LLC
100% Member Interest
Investors and Management (1)
1% General Partner Interest
99% Limited Partner Interest
6%
Plains AAP, L.P.
94%
PAA Public Limited Partners
100% Member Interest
PAA GP LLC
IDRs (2)
98% Limited Partner Interest
2% General Partner Interest
Plains All American Pipeline, L.P. (NYSE: PAA) (Partnership and the registrant)
PNG Public Limited Partners
63%
37%
PNGS GP LLC
Other Operating Subsidiaries (3)
Finance Co-Issuer (PAA Finance Corp.)
2% General Partner Interest and IDRs
98% Limited Partner Interest
PAA Natural Gas Storage, L.P. (NYSE: PNG)
Unconsolidated Entities (4)

[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.

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.

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

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.

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)

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.

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.

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:

- 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.

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.

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.

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.

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.

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.

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.

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.

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;

- 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.

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.

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 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

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:

- 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.

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.

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.

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

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

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.

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).

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 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.

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.

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.

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.

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

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.

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 66$^{2}/_{3}$% 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.

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.

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.

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.

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.

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.

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.

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		
	High	Low	Cash 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.

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
Investments in unconsolidated subsidiaries	$ —	$ —	$ 15	$ 37	$ 9

	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

[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

- 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.

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.

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.

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;

- 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

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:

	For the Twelve Months Ended December 31,			Favorable/(Unfavorable)			
				2011-2010		2010-2009	
	2011	2010	2009	$	%	$	%
	(In millions, except per unit data)						
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%

Table of Contents

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:

	For the Twelve Months Ended December 31,			Favorable/(Unfavorable)			
				2011-2010		2010-2009	
	2011	2010	2009	$	%	$	%
	(In millions, except per unit data)						
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.

[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:

Operating Results [1] (in millions, except per barrel amounts)	Year Ended December 31, 2011	 2010	 2009	Favorable/(Unfavorable) 2011-2010 $	 %	 2010-2009 $	 %
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%

Average Daily Volumes (in thousands of barrels per day) [3]	Year Ended December 31, 2011	 2010	 2009	Favorable/(Unfavorable) 2011-2010 Volumes	 %	 2010-2009 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.

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:

	For the Year Ended December 31,			Favorable/(Unfavorable)			
Operating Results [1]				**2011-2010**		**2010-2009**	
(in millions, except per barrel amounts)	**2011**	**2010**	**2009**	**$**	**%**	**$**	**%**
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%

	For the Year Ended December 31,			Favorable/(Unfavorable)			
				2011-2010		**2010-2009**	
Volumes [4] [5]	**2011**	**2010**	**2009**	**Volumes**	**%**	**Volumes**	**%**
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.

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.

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:

Operating Results [1] (in millions, except per barrel amounts)	For the Year Ended December 31, 2011	 2010	 2009	Favorable/(Unfavorable) 2011-2010 Revenues	 %	 2010-2009 Revenues	 %
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)%

Average Daily Volumes [4] (in thousands of barrels per day)	For the Year Ended December 31,			Favorable (Unfavorable)			
				2011-2010		2010-2009	
	2011	2010	2009	Volume	%	Volume	%
Crude oil lease gathering purchases	742	620	612	122	20%	8	1%
LPG sales	103	96	105	7	7%	(9)	(9)%
Waterborne cargos	21	68	55	(47)	(69)%	13	24%
Supply & Logistics segment total	866	784	772	82	10%	12	2%

[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.

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.

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.

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."

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.

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.

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

[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

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 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.

Table of Contents

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.

Table of Contents

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.

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

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.

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.

[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.

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.

Table of Contents

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.

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.

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 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."

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.

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.

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.

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 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:

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.

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:

	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

[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.

[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.

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.

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.

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. 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.

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.

Table of Contents

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.

Table of Contents

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

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

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

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

Table of Contents

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	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.

Table of Contents

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.

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

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	Director of Plains All American GP LLC	February 27, 2012

Robert V. Sinnott

/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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS

	Page
Consolidated Financial Statements	
Management's Report on Internal Control Over Financial Reporting	F-2
Report of Independent Registered Public Accounting Firm	F-3
Consolidated Balance Sheets as of December 31, 2011 and 2010	F-4
Consolidated Statements of Operations for the years ended December 31, 2011, 2010 and 2009	F-5
Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009	F-6
Consolidated Statements of Changes in Partners' Capital for the years ended December 31, 2011, 2010 and 2009	F-7
Consolidated Statements of Comprehensive Income for the years ended December 31, 2011, 2010 and 2009	F-8
Consolidated Statements of Changes in Accumulated Other Comprehensive Income for the years ended December 31, 2011, 2010 and 2009	F-8
Notes to the Consolidated Financial Statements	F-9

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

Houston, Texas
February 27, 2012

PricewaterhouseCoopers LLP

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
Total long-term liabilities	4,896	4,915
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
PARTNERS' CAPITAL		
Common unitholders (155,376,937 and 141,199,175 units outstanding, respectively)	5,249	4,189
General partner	201	153
Total partners' capital excluding noncontrolling interests	5,450	4,342
Noncontrolling interests	524	231
Total partners' capital	5,974	4,573
Total liabilities and partners' capital	$ 15,381	$ 13,703

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per unit data)

	Year Ended December 31,		
	2011	2010	2009
REVENUES			
Supply and Logistics segment revenues	$ 33,065	$ 24,989	$ 17,757
Transportation segment revenues	572	565	536
Facilities segment revenues	638	339	227
Total revenues	34,275	25,893	18,520
COSTS AND EXPENSES			
Purchases and related costs	31,564	23,921	16,656
Field operating costs	870	689	638
General and administrative expenses	294	260	211
Depreciation and amortization	249	256	236
Total costs and expenses	32,977	25,126	17,741
OPERATING INCOME	1,298	767	779
OTHER INCOME/(EXPENSE)			
Equity earnings in unconsolidated entities	13	3	15
Interest expense (net of capitalized interest of $25, $16 and $15, respectively)	(253)	(248)	(224)
Other income/(expense), net	(19)	(9)	16
INCOME BEFORE TAX	1,039	513	586
Current income tax benefit/(expense)	(38)	1	(15)
Deferred income tax benefit/(expense)	(7)	—	9
NET INCOME	994	514	580
Less: Net income attributable to noncontrolling interests	(28)	(9)	(1)
NET INCOME ATTRIBUTABLE TO PLAINS	$ 966	$ 505	$ 579
NET INCOME ATTRIBUTABLE TO PLAINS:			
LIMITED PARTNERS	$ 730	$ 330	$ 434
GENERAL PARTNER	$ 236	$ 175	$ 145
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 4.91	$ 2.41	$ 3.34
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 4.88	$ 2.40	$ 3.32
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	149	137	130

DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	150	138	131

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2011	2010	2009
		(in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 994	$ 514	$ 580
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization	249	256	236
Equity compensation expense	110	98	68
Gain on sale of linefill and base gas	(21)	(21)	(4)
Deferred income tax (benefit)/expense	7	—	(9)
Equity earnings in unconsolidated entities, net of distributions	10	6	(8)
Net cash received/(paid) for terminated interest rate or foreign currency hedging instruments	12	—	(9)
Net gain on purchase of remaining 50% interest in PNGS	—	—	(9)
Other	2	11	(19)
Changes in assets and liabilities, net of acquisitions:			
Trade accounts receivable and other	83	(59)	(744)
Inventory	518	(336)	(319)
Accounts payable and other current liabilities	401	(210)	602
Net cash provided by operating activities	2,365	259	365
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid in connection with acquisitions, net of cash acquired (Note 3)	(1,390)	(407)	(219)
Change in restricted cash	20	(20)	—
Additions to property, equipment and other	(635)	(451)	(460)
Investment in unconsolidated entities	—	—	(4)
Net cash received/(paid) for sales and purchases of linefill and base gas	(22)	25	(9)
Proceeds from sales of assets and other investing activities	7	2	6
Net cash used in investing activities	(2,020)	(851)	(686)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings/(repayments) on PAA’s revolving credit facility	(793)	49	(19)
Net borrowings/(repayments) on PAA’s hedged inventory facility	(425)	200	20
Net borrowings on PNG’s credit agreements	62	260	—
Repayment of PNGS debt	—	—	(446)
Proceeds from the issuance of senior notes	597	400	1,346
Repayments of senior notes	(200)	(175)	(430)
Net proceeds from the issuance of common units (Note 5)	889	296	458
Cash received for sale of noncontrolling interest in a subsidiary	370	268	26
Distributions paid to common unitholders (Note 5)	(575)	(512)	(468)
Distributions paid to general partner (Note 5)	(216)	(170)	(137)
Distributions to noncontrolling interests	(40)	(10)	(2)
Other financing activities	(14)	(2)	(10)
Net cash provided by/(used in) financing activities	(345)	604	338
Effect of translation adjustment on cash	(10)	(1)	(3)
Net increase/(decrease) in cash and cash equivalents	(10)	11	14
Cash and cash equivalents, beginning of period	36	25	11
Cash and cash equivalents, end of period	$ 26	$ 36	$ 25
Cash paid for interest, net of amounts capitalized	$ 254	$ 253	$ 214
Cash (received)/paid for income taxes, net of amounts refunded	$ 11	$ 21	$ (5)

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL
(in millions)

	Common Units		General Partner	Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Partners' Capital
	Units	Amount				
Balance at December 31, 2008	**123**	**$ 3,441**	**$ 111**	**$ 3,552**	**$ —**	**$ 3,552**
Net income	—	434	145	579	1	580
Sale of noncontrolling interest in a subsidiary (Note 5)	—	(37)	(1)	(38)	64	26
Distributions	—	(468)	(137)	(605)	(2)	(607)
Issuance of common units	11	447	9	456	—	456
Issuance of common units in connection with the PNGS Acquisition	2	91	2	93	—	93
Issuance of common units under LTIP	—	12	—	12	—	12
Equity compensation expense (Note 10)	—	2	3	5	—	5
Other comprehensive income	—	46	2	48	—	48
Other	—	(3)	(3)	(6)	—	(6)
Balance at December 31, 2009	**136**	**$ 3,965**	**$ 131**	**$ 4,096**	**$ 63**	**$ 4,159**
Net income	—	330	175	505	9	514
Sale of noncontrolling interest in a subsidiary (Note 5)	—	99	2	101	167	268
Distributions	—	(512)	(170)	(682)	(10)	(692)
Issuance of common units	5	290	6	296	—	296
Issuance of common units under LTIP	—	16	—	16	—	16
Equity compensation expense (Note 10)	—	4	9	13	3	16
Other comprehensive loss	—	(5)	—	(5)	—	(5)
Other	—	2	—	2	(1)	1
Balance at December 31, 2010	**141**	**$ 4,189**	**$ 153**	**$ 4,342**	**$ 231**	**$ 4,573**
Net income	—	730	236	966	28	994
Sale of noncontrolling interest in a subsidiary (Note 5)	—	63	1	64	306	370
Distributions	—	(575)	(216)	(791)	(40)	(831)
Issuance of common units	14	870	19	889	—	889
Issuance of common units under LTIP	—	15	—	15	—	15
Equity compensation expense (Note 10)	—	16	9	25	3	28
Other comprehensive loss	—	(59)	(1)	(60)	(4)	(64)
Balance at December 31, 2011	**155**	**$ 5,249**	**$ 201**	**$ 5,450**	**$ 524**	**$ 5,974**

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

	Year Ended December 31,		
	2011	2010	2009
Net income	$ 994	$ 514	$ 580
Other comprehensive income/(loss)	(64)	(5)	48
Comprehensive income	930	509	628
Less: Comprehensive income attributable to noncontrolling interests	(24)	(9)	(1)
Comprehensive income attributable to Plains	$ 906	$ 500	$ 627

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

CONSOLIDATED STATEMENTS OF CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME
(in millions)

	Derivative Instruments	Translation Adjustments	Other	Total
Balance at December 31, 2008	$ 161	$ (86)	$ —	$ 75
Reclassification adjustments	8	—	—	8
Net deferred loss on cash flow hedges	(151)	—	—	(151)
Currency translation adjustment	—	192	—	192
Proportionate share of our unconsolidated entities’ other comprehensive loss	—	—	(1)	(1)
2009 Activity	(143)	192	(1)	48
Balance at December 31, 2009	$ 18	$ 106	$ (1)	$ 123
Reclassification adjustments	(24)	—	—	(24)
Deferred loss on cash flow hedges, net of tax	(73)	—	—	(73)
Currency translation adjustment	—	92	—	92
2010 Activity	(97)	92	—	(5)
Balance at December 31, 2010	$ (79)	$ 198	$ (1)	$ 118
Reclassification adjustments	131	—	—	131
Deferred loss on cash flow hedges, net of tax	(154)	—	—	(154)
Currency translation adjustment	—	(42)	—	(42)
Proportionate share of our unconsolidated entities’ other comprehensive income	—	—	1	1
2011 Activity	(23)	(42)	1	(64)
Balance at December 31, 2011	$ (102)	$ 156	$ —	$ 54

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization and Basis of Presentation

Organization

Plains All American Pipeline, L.P. 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 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. (NYSE: PNG), we also own and operate natural gas storage facilities. Our business activities are conducted through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See Note 13 for further discussion of our three operating segments.

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. Plains All American GP LLC manages our operations and activities and employs our domestic officers and personnel. Our Canadian officers and personnel are employed by our subsidiary Plains Midstream Canada ULC. References to our “general partner,” as the context requires, include any or all of PAA GP LLC, Plains AAP, L.P. and Plains All American GP LLC. Plains AAP, L.P. and Plains All American GP LLC are essentially held by 18 owners with interests ranging from approximately 35% to less than 1%.

Definitions

Additional defined terms are used in the following notes and shall have the meanings indicated below:

AOCI	=	Accumulated other comprehensive income
Bcf	=	Billion cubic feet
Btu	=	British thermal unit
CAD	=	Canadian dollar
CERCLA	=	Federal Comprehensive Environmental Response, Compensation and Liability Act, as amended
DERs	=	Distribution equivalent rights
EBITDA	=	Earnings before interest taxes depreciation and amortization
FASB	=	Financial Accounting Standards Board
FERC	=	Federal Energy Regulatory Commission
GAAP	=	Generally accepted accounting principles in the United States
GATX	=	GATX Corporation

ICE	=	IntercontinentalExchange
IPO	=	Initial public offering
LIBOR	=	London Interbank Offered Rate
Link	=	Link Energy LLC
LLS	=	Light Louisiana Sweet
LTIP	=	Long-term incentive plan
Mcf	=	Thousand cubic feet
MLP	=	Master limited partnership
MTBE	=	Methyl tertiary-butyl ether
MQD	=	Minimum quarterly distribution
Nexen	=	Nexen Holdings U.S.A. Inc.
NJDEP	=	New Jersey Department of Environmental Protection
NPNS	=	Normal purchase normal sale
NYMEX	=	New York Mercantile Exchange
NYSE	=	New York Stock Exchange
PAA/Vulcan	=	PAA/Vulcan Gas Storage, LLC
Pacific	=	Pacific Energy Partners, L.P.

PLA	=	Pipeline loss allowance
PNG	=	PAA Natural Gas Storage, L.P.
PNGS	=	PAA Natural Gas Storage, LLC
PPT	=	Plains Products Terminals LLC (formerly known as Pacific Atlantic Terminals LLC)
Rainbow	=	Rainbow Pipe Line Company, Ltd.
RCRA	=	Federal Resource Conservation and Recovery Act, as amended
SG Resources	=	SG Resources Mississippi, LLC
SLC Pipeline	=	SLC Pipeline LLC
SOP	=	Shell Oil Products
TNM	=	Texas New Mexico
USD	=	United States dollar
Velocity	=	Velocity South Texas Gathering, LLC
White Cliffs	=	White Cliffs Pipeline, LLC
WTI	=	West Texas Intermediate
WTS	=	West Texas Sour

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present and discuss our consolidated financial position as of December 31, 2011 and 2010, and the consolidated results of our operations, cash flows, changes in partners' capital, comprehensive income and changes in accumulated other comprehensive income for the years ended December 31, 2011, 2010 and 2009. All significant intercompany transactions have been eliminated in consolidation, and certain reclassifications have been made to information from previous years to conform to the current presentation. These reclassifications do not affect net income attributable to Plains. The accompanying consolidated financial statements include Plains and all of its wholly owned subsidiaries. Investments in entities over which we have significant influence but not control are accounted for by the equity method. We evaluate our equity investments for impairment in accordance with FASB guidance with respect to the equity method of accounting for investments in common stock. An impairment of an equity investment results when factors indicate that the investment's fair value is less than its carrying value and the reduction in value is other than temporary in nature.

Subsequent events have been evaluated through the financial statements issuance date and have been included within the following footnotes where applicable.

Revision of Prior Period Financial Statements

Limited Partner and General Partner Income Allocation

During 2011, we identified an error in the manner in which we allocate net income to our limited partners and general partner. Previously, we calculated net income available to limited partners based on the distribution paid during the period by first allocating the incentive distribution paid during the period to the general partner and then allocating the remaining net income based on ownership interests (98% limited partner and 2% general partner). We have revised this allocation to utilize the distributions pertaining to the period, a portion of which are paid in the subsequent period. This revision does not impact Net Income, Net Income Attributable to Plains, Net Income Per Limited Partner Unit or total Partners' Capital. We have determined that the impact of this error is not material to the previously issued financial statements. We have presented these changes retrospectively in the Consolidated Balance Sheet, the Consolidated Statement of Operations and the Consolidated Statements of Changes in Partners' Capital, which resulted in the following changes (in millions):

	As Reported	As Revised
Net Income Attributable to Plains		
For the Year Ended December 31, 2009:		
Limited Partners	$ 443	$ 434
General Partner	136	145
	$ 579	$ 579
For the Year Ended December 31, 2010:		
Limited Partners	$ 338	$ 330
General Partner	167	175
	$ 505	$ 505

Partners' Capital		
As of December 31, 2008:		
Limited Partners	$ 3,469	$ 3,441
General Partner	83	111
	$ 3,552	$ 3,552
As of December 31, 2009:		
Limited Partners	$ 4,002	$ 3,965
General Partner	94	131
	$ 4,096	$ 4,096
As of December 31, 2010:		
Limited Partners	$ 4,234	$ 4,189
General Partner	108	153
	$ 4,342	$ 4,342

Revision of Prior Period Consolidated Statement of Cash Flows

During the second quarter of 2010, PNG completed its IPO of 13.5 million common units representing limited partner interests for net proceeds of approximately $268 million. Additionally, during the first quarter of 2009, a third party contributed approximately $26 million in cash for a 25% ownership interest in SLC Pipeline, a joint venture. The proceeds from these sales to noncontrolling interests were presented in our financial statements for the years ended December 31, 2010 and 2009 as cash flows from investing activities. Upon further evaluation, we now believe that this activity should have been presented as cash flows from financing activities. We have determined that the impact of this reclassification on our consolidated statement of cash flows for the years ended December 31, 2010 and 2009 is not material.

The following captions within the prior period consolidated statements of cash flows were impacted (in millions):

	Amounts Previously Reported Year Ended December 31,		As Revised Year Ended December 31,	
	2010	2009	2010	2009
Net cash used in investing activities	$ (583)	$ (660)	$ (851)	$ (686)
Net cash provided by financing activities	$ 336	$ 312	$ 604	$ 338
Net	$ (247)	$ (348)	$ (247)	$ (348)

Note 2—Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. We make significant estimates with respect to (i) purchases and sales accruals, (ii) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (iii) mark-to-market gains and losses on derivative instruments (pursuant to guidance issued by the FASB regarding fair value measurements), (iv) accruals and contingent liabilities, (v) equity compensation plan accruals, (vi) property and equipment and depreciation expense and (vii) allowance for doubtful accounts. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Revenue Recognition

Supply and Logistics Segment Revenues. Revenues from sales of crude oil, LPG and refined products are recognized at the time title to the product sold transfers to the purchaser, which occurs upon delivery of the product to the purchaser or its designee. Sales of crude oil, LPG and refined products consist of outright sales contracts and buy/sell arrangements as well as exchanges. Inventory purchases and sales under buy/sell transactions are treated as inventory exchanges and are presented net within Supply and Logistics segment revenues in our consolidated statements of operations.

Additionally, we may utilize derivatives in connection with the transactions described above. For commodity derivatives that are designated as cash flow hedges, derivative gains and losses are deferred to AOCI and recognized in revenues in the periods during which the underlying physical hedged transaction impacts earnings. Also, the ineffective portion of the change in fair value of cash flow hedges is recognized in revenues each period along with the change in fair value of derivatives that do not qualify for or are not designated for hedge accounting.

Transportation Segment Revenues. Revenues from pipeline tariffs and fees are associated with the transportation of crude oil and refined products at a published tariff, as well as revenues associated with line leases for committed space on a particular system that may or may not be utilized. Tariff revenues are recognized either at the point of delivery or at the point of receipt pursuant to specifications outlined in the regulated and non-regulated tariffs. Revenues associated with line-lease fees are recognized in the month to which the lease applies, whether or not the space is actually utilized. The majority of our pipeline tariff and fee revenues are based on actual volumes and rates. 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. In addition, we have certain agreements that require counterparties to ship a minimum volume over an agreed upon period. Revenue is recognized at the latter of when the volume is shipped (pursuant to specifications outlined in the tariffs) or when the counterparty's ability to make up the minimum volume has expired.

Facilities Segment Revenues. 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. 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. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements. Storage fees resulting from short-term and long-term contracts are typically recognized in revenue ratably over the term of the contract regardless of the actual storage capacity utilized. Terminal fees are recognized as the crude oil, LPG or refined product exits the terminal and is delivered to the connecting carrier or third-party terminal. Hub service fees are recognized in the period the natural gas moves across our header system. Fees from LPG fractionation, isomerization services and gas processing services are recognized in the period when the services are performed. Revenues associated with the sale of natural gas are recognized at the time title to the product sold transfers to the purchaser or its designee. In addition, we have certain agreements that require counterparties to throughput a minimum volume over an agreed upon period. Revenue is recognized at the latter of when the volume exits the terminal or when the counterparty's ability to make up the minimum volume has expired.

Purchases and Related Costs

Purchases and related costs include (i) the cost of crude oil, LPG, natural gas and refined products obtained in outright purchases, (ii) fees incurred for third-party transportation and storage, whether by pipeline, truck, rail, ship or barge, (iii) interest cost attributable to borrowings for inventory stored in a contango market and (iv) performance-related bonus accruals. These costs are recognized when incurred except in the case of products purchased, which are recognized at the time title transfers to us.

Field Operating Costs and General and Administrative Expenses

Field operating costs consist of various field operating expenses, including fuel and power costs, telecommunications, payroll and benefit costs (including equity compensation expense) for truck drivers and field personnel, third-party trucking transportation costs for our U.S. crude oil operations, maintenance and integrity management costs, regulatory compliance, environmental remediation, insurance, vehicle leases, and property taxes. General and administrative expenses consist primarily of payroll and benefit costs (including equity compensation expense), certain information systems and legal costs, office rent, contract and consultant costs and audit and tax fees.

Foreign Currency Transactions

Certain of our subsidiaries use the Canadian dollar as their functional currency. Assets and liabilities of subsidiaries with a Canadian dollar functional currency are translated at period-end rates of exchange, and revenues and expenses are translated at average exchange rates prevailing for each month. The resulting translation adjustments are made directly to a separate component of other comprehensive income in Partners' Capital reflected on our consolidated balance sheet.

Certain of our subsidiaries also enter into transactions and have monetary assets and liabilities that are denominated in a currency other than the entities' respective functional currencies. Gains and losses from the revaluation of foreign currency transactions and monetary assets and liabilities are included in the consolidated statements of operations. The revaluation of foreign currency transactions and monetary assets and liabilities resulted in a loss of approximately $2 million for the year ended December 31, 2011 and gains of approximately $2 million and $13 million for the years ended December 31, 2010 and 2009, respectively.

Cash and Cash Equivalents

Cash and cash equivalents consist of all unrestricted demand deposits and funds invested in highly liquid instruments with original maturities of three months or less and typically exceed federally insured limits. We periodically assess the financial condition of the institutions where these funds are held and believe that our credit risk is minimal. In accordance with our policy, outstanding checks are classified as accounts payable rather than negative cash. As of December 31, 2011 and 2010, accounts payable included approximately $58 million and $40 million, respectively, of outstanding checks that were reclassified from cash and cash equivalents.

Restricted Cash

Restricted cash at December 31, 2010 consisted of $20 million held by an escrow agent in connection with PNG's February 2011 acquisition of SG Resources. See Note 3 for further discussion of this acquisition. We had no restricted cash at December 31, 2011.

Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of LPG, refined products and natural gas storage. These purchasers include, but are not limited to refineries, producers, marketing and trading companies and financial institutions that are active in the physical and financial commodity markets. The majority of our accounts receivable relate to our crude oil supply and logistics activities that can generally be described as high volume and low margin activities, in many cases involving exchanges of crude oil volumes.

To mitigate credit risks related to our accounts receivable, we have in place a rigorous credit review process. We closely monitor market conditions in order to make a determination with respect to the amount, if any, of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit, "parental" guarantees or advance cash payments. At December 31, 2011 and 2010, we had received approximately $186 million and $197 million, respectively, of advance cash payments from third parties to mitigate credit risk. In addition, we enter into netting arrangements (contractual agreements that allow us and the counterparty to offset receivables and payables between the two) that cover a significant part of our transactions and also serve to mitigate credit risk.

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. We do not apply actual balances against the reserve until we have exhausted substantially all collection efforts. At December 31, 2011 and 2010, substantially all of our accounts receivable (net of allowance for doubtful accounts) were less than 30 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled approximately $5 million at both December 31, 2011 and 2010. Although we consider our allowance for doubtful trade accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

Inventory, Linefill, Base Gas and Long-term Inventory

Inventory primarily consists of crude oil, LPG and natural gas in pipelines, storage facilities and rail cars that are valued at the lower of cost or market, with cost determined using an average cost method within specific inventory pools.

At the end of each reporting period, we assess the carrying value of our inventory and make any adjustments necessary to reduce the carrying value to the applicable net realizable value. During 2011, 2010 and 2009, we did not recognize material writedowns of such inventory. Linefill, base gas and minimum working inventory requirements in assets we own are recorded at historical cost and consist of crude oil, LPG and natural gas. We classify as linefill or base gas (i) our proportionate share of barrels used to fill a pipeline such that when an incremental barrel is pumped into or enters a pipeline it forces product out at another location, (ii) barrels that represent the minimum working requirements in tanks that we own and (iii) natural gas required to maintain the minimum operating pressure of natural gas storage facilities we own. During 2011, 2010 and 2009, we recorded gains of approximately $21 million, $21 million and $4 million, respectively, on the sale of pipeline linefill for proceeds of approximately $56 million, $72 million and $24 million, respectively.

Minimum working inventory requirements in third-party assets and other working inventory in our assets that is needed for our commercial operations are included within specific inventory pools in inventory (a current asset) in determining the average cost of operating inventory. At the end of each period, we reclassify the inventory not expected to be liquidated within the succeeding twelve months out of inventory, at average cost, and into long-term inventory, which is reflected as a separate line item within other assets on the consolidated balance sheet.

Inventory, linefill, base gas and long-term inventory consisted of the following (barrels in thousands, natural gas volumes in thousands of Mcf and total value in millions):

	December 31, 2011				December 31, 2010			
	Volumes	Unit of Measure	Total Value	Price/ Unit [1]	Volumes	Unit of Measure	Total Value	Price/ Unit [1]
Inventory								
Crude oil	5,361	barrels	$ 483	$ 90.10	14,132	barrels	$ 1,100	$ 77.84
LPG	6,885	barrels	438	$ 63.62	7,395	barrels	366	$ 49.49
Natural gas [2]	16,170	Mcf	51	$ 3.15	13	Mcf	—	$ 3.87
Other	N/A		6	N/A	N/A		25	N/A
Inventory subtotal			978				1,491	
Linefill and base gas								
Crude oil	9,366	barrels	514	$ 54.88	9,159	barrels	478	$ 52.19
Natural gas [2]	14,105	Mcf	48	$ 3.40	11,194	Mcf	37	$ 3.31
LPG	31	barrels	2	$ 64.52	77	barrels	4	$ 51.95
Linefill and base gas subtotal			564				519	
Long-term inventory								
Crude oil	1,714	barrels	127	$ 74.10	1,761	barrels	128	$ 72.69
LPG	150	barrels	8	$ 53.33	505	barrels	26	$ 51.49
Long-term inventory subtotal			135				154	
Total			$ 1,677				$ 2,164	

[1] Price per unit of measure represents a weighted average associated with various grades, qualities and locations; accordingly, these prices may not coincide with any published benchmarks for such products.

[2] The volumetric ratio of Mcf of natural gas to crude Btu equivalent is 6:1; thus, natural gas volumes can be approximately converted to barrels by dividing by 6.

Property and Equipment

In accordance with our capitalization policy, costs associated with acquisitions and improvements that expand our existing capacity, including related interest costs, are capitalized. For the years ended December 31, 2011, 2010 and 2009, capitalized interest was $25 million, $16 million and $15 million, respectively. We also capitalize expenditures 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. Repair and maintenance expenditures incurred in order to maintain the day to day operation of our existing assets are expensed as incurred.

Property and equipment, net is stated at cost and consisted of the following (in millions):

	Estimated Useful Lives (Years)	December 31, 2011	December 31, 2010
Crude oil pipelines and facilities	10 - 70	$ 4,467	$ 4,303
Storage and terminal facilities	30 - 70	3,385	2,740
Trucking equipment and other	3 - 15	110	106

Construction in progress	—	693	304
Office property and equipment	2 - 50	99	95
Land and other	N/A	275	266
		9,029	7,814
Accumulated depreciation		(1,289)	(1,123)
Property and equipment, net		$ 7,740	$ 6,691

Depreciation expense for the years ended December 31, 2011, 2010 and 2009 was $196 million, $235 million and $216 million, respectively.

We calculate our depreciation using the straight-line method, based on estimated useful lives and salvage values of our assets. During 2011 and 2010, we extended the depreciable lives of several of our crude oil and other storage facilities and pipeline systems based on an ongoing 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 current technology. These depreciable life extensions will prospectively reduce depreciation expense. For the years ended December 31, 2011 and 2010, these extensions reduced depreciation expense by approximately $60 million (incrementally by $37 million as compared to the prior year) and $23 million, respectively.

We also classify gains and losses on sales of assets and asset impairments as a component of depreciation and amortization in the consolidated statements of operations. During the years ended 2011 and 2010, we recognized losses on disposition of certain assets and impairments for assets taken out of service of approximately $11 million and $13 million, respectively.

Equity Method of Accounting

Our investments in the following entities are accounted for under the equity method of accounting:

Entity	Type of Operation	Our Ownership Interest
Settoon Towing, LLC	Barge Transportation Services	50%
White Cliffs Pipeline, L.L.C.	Crude Oil Pipeline	34%
Frontier Pipeline Company	Crude Oil Pipeline	22%
Butte Pipe Line Company	Crude Oil Pipeline	22%

We do not consolidate any part of the assets or liabilities of our equity investees. Our share of net income or loss is reflected as one line item on the income statement entitled “Equity earnings in unconsolidated entities” and will increase or decrease, as applicable, the carrying value of our investments in unconsolidated entities on the balance sheet. In addition, we include a proportionate share of our equity method investees’ unrealized gains and losses in other comprehensive income on our consolidated balance sheet. We also adjust our investment balances in these investees by the like amount. Distributions to the Partnership will reduce the carrying value of our investments and will be reflected on our cash flow statement netted against equity in earnings. In turn, contributions will increase the carrying value of our investments and will be reflected on our cash flow statement within investing activities.

Noncontrolling Interests

We account for noncontrolling interests in subsidiaries in accordance with FASB guidance specific to noncontrolling interests. FASB guidance requires all entities to report noncontrolling interests in subsidiaries as a component of equity in the consolidated financial statements. Noncontrolling interest represents the portion of assets and liabilities in a consolidated subsidiary that is owned by a third-party. See Note 5 for additional discussion regarding our noncontrolling interests.

Asset Retirement Obligations

FASB guidance establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including estimates related to (i) the time of the liability recognition, (ii) initial measurement of the liability, (iii) allocation of asset retirement cost to expense, (iv) subsequent measurement of the liability and (v) financial statement disclosures. FASB guidance also requires that the cost for asset retirement should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method.

Some of our assets, primarily related to our transportation and facilities segments, have contractual or regulatory obligations to perform remediation and, in some instances, dismantlement and removal activities when the assets are abandoned. These obligations include varying levels of activity including disconnecting inactive assets from active assets, cleaning and purging assets, and in some cases, completely removing the assets and returning the land to its original state. These assets have been in existence for many years and with regular maintenance will continue to be in service for many years to come. It is not possible to predict when demand for these transportation or storage services will cease, and we do not believe that such demand will cease for the foreseeable future. Accordingly, we believe the date when these assets will be abandoned is indeterminate. With no reasonably determinable abandonment date, we cannot reasonably estimate the fair value of the associated asset retirement obligations. We will record asset retirement obligations for these assets in the period in which sufficient information becomes available for us to reasonably determine the settlement dates.

A small portion of our contractual or regulatory obligations is related to assets that are inactive or that we plan to take out of service and, although the ultimate timing and costs to settle these obligations are not known with certainty, we have recorded a reasonable estimate of these obligations. We have estimated that the fair value of these obligations was approximately $9 million and $5 million, respectively, at December 31, 2011 and 2010.

Impairment of Long-Lived Assets

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written down to estimated fair value in accordance with FASB guidance with respect to the accounting for the impairment or disposal of long-lived assets. Under this guidance, a long-lived asset is tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount by which the carrying value exceeds the fair value of the asset is recognized.

We periodically evaluate property and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. The evaluation is highly dependent on the underlying assumptions of related cash flows. The subjective assumptions used to determine the existence of an impairment in carrying value include:

- whether there is an indication of impairment;
- 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.

During 2011, 2010 and 2009, impairments of approximately $5 million, $13 million and less than $1 million, respectively, were recognized related predominately 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.

Goodwill

Goodwill represents the future economic benefits arising from assets acquired in a business combination that are not individually identified and separately recognized. In accordance with FASB guidance, we test goodwill at least annually (as of June 30) and on an interim basis if a triggering event occurs, such as an adverse change in business climate, to determine whether an impairment has occurred. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit. A reporting unit is an operating segment or one level below an operating segment for which discrete financial information is available and regularly reviewed by segment management. Our reporting units are our operating segments. FASB guidance requires a two step approach to testing goodwill for impairment. In Step 1, we compare the fair value of the reporting unit with the respective book values, including goodwill, by using an income approach based on a discounted cash flow analysis. This approach requires us to make long-term forecasts of future revenues, expenses and other expenditures. Those forecasts require the use of various assumptions and estimates, the most significant of which are net revenues (total revenues less purchases and related costs), operating expenses, general and administrative expenses and the weighted average cost of capital. Fair value of the reporting units is determined using significant unobservable inputs, or level 3 inputs in the fair value hierarchy. When the fair value is greater than book value, then the reporting unit's goodwill is not considered impaired. If the book value is greater than fair value, then we proceed to Step 2. In Step 2, we compare the implied fair value of the reporting unit's goodwill with the book value. A goodwill impairment loss is recognized if the carrying amount exceeds its fair value.

Through Step 1 of our annual testing of goodwill for potential impairment, which also includes a sensitivity analysis regarding the excess of our reporting unit's fair value over book value, we determined that the fair value of each reporting unit was substantially greater than its respective book value, and therefore goodwill was not considered impaired. We will continue to monitor various potential indicators (including the financial markets) to determine if a triggering event occurs and will perform another goodwill impairment analysis if necessary.

The table below reflects our changes in goodwill (in millions):

	Transportation	Facilities	Supply & Logistics	Total [1]
Balance at December 31, 2009	$ 608	$ 308	$ 371	$ 1,287
2010 Goodwill Related Activity:				
Nexen acquisition	18	—	54	72
Purchase price accounting adjustments [2]	3	—	—	3
Foreign currency translation adjustments	11	—	3	14
Balance at December 31, 2010	$ 640	$ 308	$ 428	$ 1,376
2011 Goodwill Related Activity:				
Southern Pines acquisition [2]	—	301	—	301
Gardendale Gathering System acquisition[2]	155	—	—	155
Foreign currency translation adjustments	(5)	—	(1)	(6)
Purchase price accounting adjustments and other [2]	28	—	—	28
Balance at December 31, 2011	$ 818	$ 609	$ 427	$ 1,854

[1] As of December 31, 2011, the total carrying amount of goodwill is net of approximately $3 million of accumulated impairment losses.

[2] Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation. This preliminary goodwill balance may be adjusted when the purchase price allocation is finalized. See Note 3 for additional discussion of our acquisitions.

Other Assets, Net

Other assets, net of accumulated amortization, consist of the following (in millions):

	December 31,	
	2011	2010
Debt issue costs	$ 53	$ 47
Fair value of derivative instruments	20	20
Intangible assets	498	311
Other	59	58
	630	436
Accumulated amortization	(84)	(54)
	$ 546	$ 382

Costs incurred in connection with the issuance of long-term debt and amendments to our credit facilities are capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the "effective interest" method of amortization. Fully amortized debt issue costs and the related accumulated amortization are written off in conjunction with the refinancing or termination of the applicable debt arrangement. We capitalized debt issue costs of approximately $18 million and $7 million in 2011 and 2010, respectively. Approximately $11 million of gross debt issue costs were removed from our Consolidated Balance Sheet during 2011, primarily related to the restructuring of our credit facilities in August 2011.

Amortization expense related to other assets (including finite-lived intangible assets) for the three years ended December 31, 2011, 2010 and 2009 was $44 million, $22 million and $19 million, respectively. Our amortization expense for finite-lived intangible assets for the years ended December 31, 2011, 2010 and 2009 was $36 million, $14 million and $14 million, respectively.

Intangible assets that have finite lives are tested for impairment when events or circumstances indicate that the carrying value may not be recoverable. Our intangible assets that have finite lives consist of the following (in millions):

		December 31, 2011			December 31, 2010		
	Estimated Useful Lives (Years)	Cost	Accumulated Amortization	Net	Cost	Accumulated Amortization	Net
Customer contracts and relationships	1-20	$ 426	$ (61)	$ 365	$ 221	$ (34)	$ 187
Property tax abatement	7-13	38	(6)	32	23	(2)	21
Other agreements	30-70	26	(1)	25	22	(1)	21
Emission reduction credits [1]	N/A	8	—	8	45	—	45
		$ 498	$ (68)	$ 430	$ 311	$ (37)	$ 274

[1] Emission reduction credits are finite-lived and are subject to surrender from the date that they are first utilized. During 2011, approximately $37 million of emission reduction credits were surrendered as part of the permitting process associated with facility construction and were reclassified into construction in progress, which is included within Property and equipment on our Consolidated Balance Sheet.

The increase in intangible assets from December 31, 2010 was primarily related to intangibles acquired in connection with the Southern Pines, Gardendale Gathering System and Western acquisitions. See Note 3 for further discussion of our acquisition activities.

We estimate that our amortization expense related to finite-lived intangible assets for the next five years will be as follows (in millions):

2012	$ 50
2013	$ 47
2014	$ 44
2015	$ 41
2016	$ 36

Environmental Matters

We record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We do not discount our environmental remediation liabilities to present value. We also record receivables for amounts recoverable from insurance or from third parties under indemnification agreements in the period that we determine the costs are probable of recovery.

We expense expenditures that relate to an existing condition caused by past operations that do not contribute to current or future profitability. We record environmental liabilities assumed in business combinations based on the estimated fair value of the environmental obligations caused by past operations of the acquired company. See Note 11 for further discussion of environmental remediation matters.

Income and Other Taxes

We estimate (i) income taxes in the jurisdictions in which we operate, (ii) net deferred tax assets and liabilities based on temporary differences that are expected to be recovered or settled at the enacted tax rates expected in future periods, (iii) valuation allowances for deferred tax assets and (iv) contingent tax liabilities for estimated exposures related to our current tax positions.

We adopted the provisions of the FASB guidance related to accounting for uncertainty in income taxes on January 1, 2007. Pursuant to this guidance, we must recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits of the tax position and also the past administrative practices and precedents of the taxing authority. As of December 31, 2011 and 2010, we have not recognized any material amounts in connection with uncertainty in income taxes.

See Note 7 for discussion of U.S. federal and state taxes and Canadian federal and provincial taxes.

Derivative Instruments and Hedging Activities

We record all open derivative instruments on the balance sheet as either assets or liabilities measured at their fair value pursuant to FASB guidance. This guidance requires that changes in the fair value of derivative instruments be recognized currently in earnings unless specific hedge accounting criteria are met. For cash flow hedges, the effective portion of the change in fair value is deferred in AOCI and reclassified into earnings when the underlying transaction affects earnings. For fair value hedges, the change in fair value of the derivative instrument is recognized in earnings. Additionally, the change in fair value of the hedged item, attributable to the hedged risk, is recognized as a basis adjustment to the hedged item and is also recognized in earnings. See Note 6 for further discussion.

Equity Compensation

See Note 10 for information regarding our accounting for equity compensation awards.

Net Income Per Limited Partner Unit

Basic and diluted net income per unit is determined by dividing our limited partners' interest in net income attributable to Plains by the weighted average number of limited partner units outstanding during the period. Pursuant to FASB guidance regarding the application of the two-class method for MLPs, the limited partners' interest in net income attributable to Plains is calculated by first reducing net income attributable to Plains by the distribution pertaining to the current period's net income (including the incentive distribution interest in excess of the 2% general partner interest). Then, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner and limited partners in accordance with the contractual terms of the partnership agreement.

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the years ended 2011, 2010 and 2009:

	Year Ended December 31,		
	2011	2010	2009
Numerator for basic and diluted earnings per limited partner unit:			
Net income attributable to Plains	$ 966	$ 505	$ 579
Less: General partner's incentive distribution [1]	(221)	(168)	(136)
Less: General partner 2% ownership	(15)	(7)	(9)
Net income available to limited partners in accordance with the application of the two-class method for MLPs	$ 730	$ 330	$ 434
Denominator:			
Basic weighted average number of limited partner units outstanding	149	137	130
Effect of dilutive securities:			
Weighted average LTIP units [2]	1	1	1
Diluted weighted average number of limited partner units outstanding	150	138	131
Basic net income per limited partner unit	$ 4.91	$ 2.41	$ 3.34
Diluted net income per limited partner unit	$ 4.88	$ 2.40	$ 3.32

[1] We calculate net income available to limited partners based on the distributions pertaining to the current period's net income. After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner and limited partners in accordance with the contractual terms of the partnership agreement.

[2] Our LTIP awards (described in Note 10) that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards that are deemed to be dilutive are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB.

Recent Accounting Pronouncements

In December 2010, the FASB issued updated accounting guidance related to the calculation of the carrying amount of a reporting unit when performing the first step of a goodwill impairment test. More specifically, this update will require an entity to use an equity premise when performing the first step of a goodwill impairment test, and if a reporting unit has a zero or negative carrying amount, the entity must assess and consider qualitative factors to determine whether it is more likely than not that a goodwill impairment exists. The new accounting guidance is effective for impairment tests performed during fiscal years (and interim periods within those years) that begin after December 15, 2010. We adopted this guidance on January 1, 2011; however, as we currently do not have any reporting units with a zero or negative carrying amount, our adoption of this guidance did not have a material impact on our financial position, results of operations or cash flows.

In December 2010, the FASB issued updated accounting guidance to clarify that pro forma disclosures should be presented as if a business combination that is determined to be material on an individual or aggregate basis occurred at the beginning of the prior annual period for purposes of preparing both the current reporting period and the prior reporting period pro forma financial information. These disclosures should be accompanied by a narrative description about the nature and amount of material, nonrecurring pro forma adjustments. The new accounting guidance is effective for business combinations consummated in periods

beginning after December 15, 2010 and should be applied prospectively as of the date of adoption. We adopted this guidance on January 1, 2011. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

In January 2010, the FASB issued guidance to enhance disclosures related to the existing fair value hierarchy disclosure requirements. The fair value hierarchy consists of designation to one of three levels based on the nature of the inputs used in the valuation process. Level 1 measurements generally reflect quoted market prices in active markets for identical assets or liabilities, level 2 measurements generally reflect the use of significant observable inputs, and level 3 measurements typically utilize significant unobservable inputs. This new guidance requires a gross presentation of activities within the level 3 rollforward. This guidance was effective for annual and interim reporting periods beginning after December 15, 2010. We adopted this guidance on January 1, 2011. See Note 6 for additional disclosure. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

Accounting Pronouncements Not Yet Effective

In December 2011, the FASB issued an accounting standard update that will require disclosure of information to help reconcile differences in the offsetting requirements for assets and liabilities under U.S. GAAP and IFRS. Under this new guidance entities are required to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position, as well as instruments and transactions subject to an agreement similar to a master netting arrangement. In addition, the standard requires disclosure of collateral received and posted in connection with master netting agreements or similar arrangements. Entities will need to provide the following enhanced disclosures for both assets and liabilities within the scope of the new standard: (i) the gross amounts of those recognized assets and those recognized liabilities; (ii) the amounts offset to determine the net amounts presented in the statement of financial position; (iii) the net amounts presented in the statement of financial position; (iv) the amounts subject to an enforceable master netting arrangement or similar agreement not otherwise included in (ii); and (v) the net amount after deducting the amounts in (iv) from the amounts in (iii). The standard affects all entities with balances presented on a net basis in the financial statements, derivative assets and derivative liabilities, repurchase agreements, and financial assets and financial liabilities executed under a master netting or similar arrangement. Accordingly, the adoption of this guidance is not expected to have a material impact on our financial position as this standard only impacts the presentation of such financial information. This guidance is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods.

In September 2011, the FASB issued guidance to simplify the goodwill impairment test by permitting entities to perform a qualitative assessment to determine whether further impairment testing is necessary. If qualitative factors indicate that it is more likely than not that the fair value of a reporting unit is greater than its carrying amount, an entity need not perform the two-step goodwill impairment test. This guidance is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011, with earlier adoption permitted. The adoption of this guidance is not expected to have a material impact on our financial position, results of operations or cash flows.

In June 2011, the FASB issued new guidance regarding the presentation of comprehensive income. This guidance requires entities to present reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statement in which the components of net income and components of other comprehensive income are presented. It also eliminates the current option under U.S. GAAP to present components of other comprehensive income within the statement of changes in stockholders' equity. The components of comprehensive income will be required to be presented within either (i) a single continuous statement of comprehensive income or (ii) two separate but consecutive statements. This guidance is effective for interim and annual periods beginning after December 15, 2011, with earlier adoption permitted. Since this issuance only impacts the presentation of such financial information, adoption of this guidance is not expected to have a material impact on our financial position, results of operations or cash flows. On December 23, 2011, the FASB issued guidance to defer the new requirement to present reclassifications of other comprehensive income on the face of the income statement. Companies will still be required to adopt the other requirements contained in the new accounting standard for the presentation of comprehensive income.

In May 2011, the FASB issued guidance to amend certain measurement and disclosure requirements related to fair value in an effort to improve consistency with international reporting standards. This guidance is effective prospectively for interim and annual reporting periods beginning after December 15, 2011. Early adoption is not permitted. The adoption of this guidance is not expected to have a material impact on our financial position, results of operations or cash flows.

Note 3—Acquisitions and Dispositions

Pending Acquisition

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 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.

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

2011 Acquisitions

Southern Pines Acquisition

On February 9, 2011, PNG acquired 100% of the equity interests in SG Resources from SGR Holdings, L.L.C. (the “Southern Pines Acquisition”) for an aggregate purchase price of approximately $765 million in cash (approximately $750 million, net of cash and other working capital acquired). The primary asset of SG Resources is the Southern Pines Energy Center (“Southern Pines”), a FERC-regulated, salt-cavern natural gas storage facility located in Greene County, Mississippi. In connection with this acquisition, PNG obtained financing through a private placement of PNG common units to third-party purchasers and to us. See Note 5 for further discussion.

The preliminary fair value of assets acquired and liabilities assumed is as follows (in millions):

Description		Amount	Average Depreciable Life (in years)
Inventory	$	14	N/A
Property and equipment, net		341	5 - 70
Base gas		3	N/A
Other working capital (including $13 million of cash)		14	N/A
Intangible assets		92	2 - 10
Goodwill		301	N/A
Total	$	765	

The fair value of assets acquired and liabilities assumed is preliminary and subject to change, pending completion of internal valuation procedures primarily related to the valuation of intangible assets and the various components of the property and equipment acquired. The preliminary allocation of fair value to intangible assets above is comprised of a tax abatement valued at approximately $15 million and contracts valued at approximately $77 million, which have lives ranging from 2 to 10 years. Amortization of customer contracts under the declining balance method of amortization was approximately $13 million during the year ended December 31, 2011 and is estimated to be approximately $14 million, $13 million, $11 million and $8 million for the years ending December 31, 2012, 2013, 2014 and 2015, respectively. Goodwill or indefinite lived intangible assets will not be subject to depreciation or amortization, but will be subject to periodic impairment testing and, if necessary, will be written down to fair value should circumstances warrant. We expect to finalize our purchase price allocation during the first quarter of 2012.

Several factors contributed to a purchase price in excess of the fair value of the net tangible and intangible assets acquired. Such factors included the strategic location of the Southern Pines facility, the limited alternative locations and the extended lead times required to develop and construct such facility, along with its operational flexibility, organic expansion capabilities and synergies anticipated to be obtained from combining Southern Pines with our existing asset base. This acquisition is reflected within our facilities segment.

Also in connection with the Southern Pines Acquisition, PNG became the owner, with the ability to remarket in the future, and ultimate obligor of the $100,000,000 Mississippi Business Finance Corporation Gulf Opportunity Zone Industrial Development Revenue Bonds (SG Resources Mississippi, LLC Project), Series 2009 and the $100,000,000 Mississippi Business Finance Corporation Gulf Opportunity Zone Industrial Development Revenue Bonds (SG Resources Mississippi, LLC Project), Series 2010 (collectively, the “GO Bonds”). These were originally issued to fund the expansion of the Southern Pines facility. PNG remarketed the GO Bonds in August 2011 (see Note 4).

In May 2011, PNG entered into an agreement with the former owners of SG Resources with respect to certain outstanding issues and purchase price adjustments as well as the distribution of the remaining 5% of the purchase price that was escrowed at closing (totaling $37 million). Pursuant to this agreement, PNG received approximately $10 million and the balance was remitted to the former owners. Funds received by PNG have been and will continue to be used to fund anticipated facility development and other related costs identified subsequent to closing. Approximately $3 million of capital expenditures were incurred related to matters covered by the agreement through December 31, 2011. Remaining amounts will be utilized to offset applicable cavern development expenditures as incurred. Any remaining amounts upon completion of applicable cavern development procedures will reduce goodwill. Additionally, the parties executed releases of any existing and future claims, subject to customary carve-outs.

Other 2011 Acquisitions

Western Acquisition. On December 29, 2011, we completed two transactions with Western Refining for a combined purchase price of approximately $220 million in cash. Through the first transaction, we acquired crude oil, refined products and LPG storage and the associated manifold and pumping equipment located at Western’s Yorktown, Virginia refinery site, which we will operate as a terminal, as well as certain intangible assets. The second transaction included an 82-mile, 16-inch segment of pipeline that originates in Chaves County, New Mexico and connects into our Basin Pipeline system at Jal, New Mexico. The transaction includes associated tankage, piping and other related assets at the Lynch and Jal Stations.

Gardendale Gathering System Acquisition. On November 29, 2011, we completed the acquisition of 100% of the member interests in Velocity from Velocity Midstream Partners, LLC for an aggregate purchase price of approximately $349 million in cash. The assets acquired included approximately 120 miles of crude oil and condensate gathering and transportation pipelines (the "Gardendale Gathering System") in the Eagle Ford Shale. We recognized goodwill of approximately $155 million associated with this acquisition, which was primarily related to the potential incremental income from anticipated growth projects.

Additional 2011 Acquisitions. During 2011, we completed six additional acquisitions for an aggregate consideration of approximately $20 million. These acquisitions included propane storage and terminal facilities included within our facilities segment, a trucking business included in our transportation segment as well as the right to ship on third-party pipelines, the revenues of which are included in our supply and logistics segment.

The preliminary determination of fair value of assets acquired and liabilities assumed for all other acquisitions completed during 2011, including the Western and Gardendale Gathering System acquisitions, is as follows (in millions):

Description		Amount
Linefill	$	2
Property and equipment, net		282
Other working capital		(7)
Intangible assets		152
Environmental liability		(9)
Goodwill		169
Total	$	589

2010 Acquisitions

Nexen Acquisition. On December 30, 2010, we acquired from Nexen Holdings U.S.A. Inc. entities that hold crude oil gathering and transportation assets that primarily service Bakken area producers. The purchase price was approximately $229 million, in cash, including approximately $170 million for the business and physical assets and approximately $59 million for approximately 460,000 barrels of inventory and other working capital adjustments. The assets are primarily located in Northwestern North Dakota and Northeastern Montana and include (i) a lease gathering business, (ii) the Robinson Lake pipeline, a FERC-regulated 20-mile, 8-inch pipeline, (iii) eight truck terminals and (iv) various other contractual rights. These assets are included within our transportation and supply and logistics segments. We recognized goodwill of approximately $83 million associated with this acquisition.

Other 2010 Acquisitions. During 2010, we completed five additional acquisitions for aggregate consideration of approximately $178 million. These acquisitions included (i) a 34% interest in White Cliffs that is reflected within our transportation segment, (ii) an additional 11% interest in Capline pipeline that is reflected within our transportation segment and (iii) various other assets reflected within both our transportation and facilities segments. We did not recognize any goodwill for these acquisitions.

2009 Acquisitions

PNGS Acquisition. On September 3, 2009, we acquired the remaining 50% indirect interest in PAA/Vulcan for an aggregate purchase price of $215 million ("PNGS Acquisition"). The $215 million purchase price consisted of $90 million in cash paid at closing, approximately $91 million in equivalent value of PAA common units (1,907,305 PAA common units based on a 20 business-day average closing price per unit) issued to Vulcan Gas Storage LLC 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 the achievement of certain performance milestones and events expected to occur over the next several years. Upon completion of the PNG IPO in May 2010, we paid the first $20 million installment. See Note 5 for additional discussion of the PNG IPO. The fair value of the remaining contingent consideration is approximately $19 million at December 31, 2011.

As a result of the transaction, we owned 100% of PNGS's natural gas storage business and related operating entities, which were accounted for on a consolidated basis beginning in September 2009. We historically accounted for our 50% indirect interest in PAA/Vulcan under the equity method. We recorded a net gain of approximately $9 million, recorded in other income, in connection with (i) adjusting our previously owned 50% investment in PAA/Vulcan to fair value and (ii) terminating an agreement to supply natural gas to PNGS.

At the time of the PNGS Acquisition, PNGS owned and operated two natural gas storage facilities located in Louisiana and Michigan that had an aggregate working gas storage capacity of 40 Bcf and an aggregate peak injection and withdrawal capacity of 1.7 Bcf per day and 3.2 Bcf per day, respectively. Substantially all of PNGS's revenues were derived from the provision of firm storage services under multi-year, fee-based contracts. The gas storage operations are reflected in our facilities segment.

The purchase price consisted of the following (in millions):

Cash	$	90
PAA equity		91
Paid at closing		181
Fair value of contingent consideration [(1)]		34
Total purchase price	$	215

[(1)] The deferred contingent cash consideration is payable in cash in two installments of $20 million each upon the achievement of certain performance milestones and events expected to occur over the next several years. The fair value of the deferred contingent cash consideration was based on a discounted cash flow model utilizing a discount rate of approximately 9%. Upon completion of the PNG IPO in May 2010, we paid the first $20 million contingent consideration installment.

The determination of fair value of the assets and liabilities related to the PNGS Acquisition was as follows (in millions):

Property, plant and equipment	$ 791
Base gas	28
Goodwill	25
Intangible assets	23
Working capital and other long-term assets and liabilities	9
Debt	(446)
Total	$ 430

Other 2009 Acquisitions. During 2009, we completed six additional acquisitions for an aggregate consideration of approximately $178 million. These acquisitions included an additional 21% undivided joint interest in Capline and associated tankage, as well as various crude oil pipelines and pipeline systems that are all included within our transportation segment. We also acquired a natural gas processing business, a refined products terminal and various crude oil storage tanks and other related assets that are all included within our facilities segment. The goodwill associated with such acquisitions was approximately $27 million as of December 31, 2011.

Dispositions

During 2011, 2010 and 2009, we sold various property and equipment for proceeds totaling approximately $12 million, $3 million and $4 million, respectively. A loss of approximately $6 million, a gain of less than $1 million and a loss of less than $1 million were recognized in 2011, 2010 and 2009, respectively, related to these sales.

Note 4—Debt

Debt consisted of the following (in millions):

	December 31, 2011	December 31, 2010
SHORT-TERM DEBT		
Credit Facilities [1]:		
Senior secured hedged inventory facility bearing a weighted-average interest rate of 1.5% and 2.1% at December 31, 2011 and December 31, 2010, respectively	$ 75	$ 500
PAA senior unsecured revolving credit facility, bearing a weighted-average interest rate of 1.6% and 0.7% at December 31, 2011 and December 31, 2010, respectively [2]	32	824
PNG senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.1% and 3.2% at December 31, 2011 and December 31, 2010, respectively [3]	68	—
4.25% senior notes due September 2012 [4]	500	—
Other	4	2
Total short-term debt	679	1,326
LONG-TERM DEBT		
Senior Notes:		
4.25% senior notes due September 2012 [4]	—	500
7.75% senior notes due October 2012	—	200
5.63% senior notes due December 2013	250	250
5.25% senior notes due June 2015	150	150
3.95% senior notes due September 2015	400	400
5.88% senior notes due August 2016	175	175
6.13% senior notes due January 2017	400	400
6.50% senior notes due May 2018	600	600
8.75% senior notes due May 2019	350	350
5.75% senior notes due January 2020	500	500
5.00% senior notes due February 2021	600	—
6.70% senior notes due May 2036	250	250
6.65% senior notes due January 2037	600	600
Unamortized discounts	(13)	(12)
Senior notes, net of unamortized discounts	4,262	4,363
Credit Facilities and Other:		
PNG senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.1% and 3.2% at December 31, 2011 and December 31, 2010, respectively [3]	54	260
PNG GO Zone term loans, bearing a weighted-average interest rate of 1.5% at December 31, 2011	200	—
Other	4	8
Total long-term debt [2]	4,520	4,631
Total debt [5]	$ 5,199	$ 5,957

[1] During August 2011, we renewed, extended or refinanced our principal bank credit facilities, including PNG's credit facility. See "Credit Facilities" below for further discussion.

[2] We classify as short-term certain borrowings under our PAA senior unsecured revolving credit facility. These borrowings are primarily designated as working capital borrowings, must be repaid within one year and are primarily for hedged LPG and crude oil inventory and NYMEX and ICE margin deposits.

[3] PNG classifies as short-term debt any borrowings under the PNG senior unsecured revolving credit facility that have been designated as working capital borrowings and must be repaid within one year. Such borrowings are primarily related to a portion of PNG's hedged natural gas inventory.

[4] Our $500 million 4.25% senior notes will mature in September 2012 and thus are classified as short-term at December 31, 2011. The proceeds from the the issuance of these notes are being used to supplement capital available from our hedged inventory facility to fund working capital needs associated with base levels of routine waterborne cargos and for seasonal LPG inventory requirements. At December 31, 2010, approximately $466 million had been used to fund hedged inventory and would have been classified as short-term debt if funded on our credit facilities. After the $500 million 4.25% senior notes mature, we intend to use our recently renewed and expanded credit facilities to finance hedged inventory. Concurrent with the issuance of these senior notes, we entered into interest rate swaps whereby we receive fixed payments at 4.25% and pay three-month LIBOR plus a spread. See Note 6 for further discussion of our interest rate swaps.

[5] Our fixed-rate senior notes have a face value of approximately $4.8 billion and $4.4 billion as of December 31, 2011 and December 31, 2010, respectively. We estimate the aggregate fair value of these notes as of December 31, 2011 and December 31, 2010 to be approximately $5.4 billion and $4.7 billion, respectively. Our fixed-rate senior notes are traded among institutions, which trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near quarter end. We estimate that the carrying value of outstanding borrowings under our credit facilities and agreements approximates fair value as interest rates reflect current market rates.

Credit Facilities

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.

During August 2011, we renewed, extended or refinanced our principal bank credit facilities, as discussed further below. In connection with these transactions, we terminated a $500 million, 364-day senior unsecured credit facility that was scheduled to expire in January 2012.

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. Amounts outstanding were approximately $32 million at December 31, 2011 under this facility and approximately $824 million at December 31, 2010 under our previous revolving credit facility.

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. 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. Subject to obtaining additional or increased lender commitments, the committed amount of this new facility may be increased to $1.35 billion. 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. Amounts outstanding were approximately $75 million at December 31, 2011 under this facility and approximately $500 million at December 31, 2010 under our previous hedged inventory facility.

PNG senior unsecured credit agreement. In August 2011, PNG entered into a new $450 million, five-year 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). 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. This new PNG facility replaced a $400 million, three year senior unsecured revolving credit facility that was scheduled to mature in May 2013. Amounts outstanding were approximately $322 million at December 31, 2011 under the PNG credit agreement and approximately $260 million at December 31, 2010 under PNG's previous revolving credit facility.

Senior Note Issuances

In January 2011, we completed the issuance of $600 million of 5.00% senior notes due February 1, 2021. The senior notes were sold at 99.521% of face value. Interest payments are due on February 1 and August 1 of each year, beginning on August 1, 2011. We used the net proceeds from this offering to reduce outstanding borrowings under our credit facilities and for general partnership purposes.

In July 2010, we completed the issuance of $400 million of 3.95% senior notes due September 15, 2015. The senior notes were sold at 99.889% of face value. Interest payments are due on March 15 and September 15 of each year, which began on September 15, 2010. We used the net proceeds from this offering to repay outstanding indebtedness under our credit facilities.

Our senior notes are co-issued, jointly and severally, by Plains All American Pipeline, L.P. and a 100%-owned consolidated finance subsidiary (neither of which have independent assets or operations). In August 2011, as permitted under the indentures governing the senior notes, PAA released the guarantees of each subsidiary guarantor in conjunction with the refinancing of our credit facilities. As such, our senior notes are no longer guaranteed by any of our subsidiaries.

Senior Note Repayments and Redemptions

On February 7, 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, recorded to Other income/(expense), net in our consolidated statement of operations. We utilized cash on hand and available capacity under our credit facilities to redeem these notes.

On September 15, 2010, our $175 million, 6.25% senior notes due 2015 were redeemed in full. In conjunction with the early redemption, we recognized a loss of approximately $6 million. We utilized cash on hand and available capacity under our credit facilities to redeem these notes.

Maturities

The weighted average life of our long-term debt outstanding at December 31, 2011 was approximately 10 years and the aggregate maturities for the next five years and thereafter are as follows (in millions):

Calendar Year	Payment
2012 [(1)]	$ —
2013	250
2014	—
2015	550
2016	429
Thereafter	3,300
Total [(2)]	$ 4,529

[(1)] Our $500 million 4.25% senior notes will mature in September 2012 and thus are classified as short-term at December 31, 2011.

[(2)] Excludes aggregate unamortized net discount of $13 million and other long-term obligations of $4 million.

Covenants and Compliance

Our credit agreements and the indentures governing the senior notes contain cross-default provisions. Our credit agreements prohibit declaration or payments of 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:

- grant liens on certain property;

- incur indebtedness, including capital leases;
- sell substantially all of our assets or enter into a merger or consolidation;
- engage in certain transactions with affiliates; and
- enter into certain burdensome agreements.

The PAA senior unsecured revolving credit facility, the senior secured hedged inventory facility and the PAA senior unsecured 364-day revolving credit facility treat a change of control as an event of default and also require us to maintain a debt-to-EBITDA coverage ratio that will not be greater than 5.00 to 1.00 or 5.50 to 1.00 on all outstanding debt during an acquisition period (generally, the period consisting of three fiscal quarters following an acquisition greater than $150 million).

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

A default under our credit facilities would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit agreements, our ability to make distributions of available cash is not restricted. As of December 31, 2011, we were in compliance with the covenants contained in our credit agreements and indentures.

PNG’s credit agreement contains covenants and events of default provisions that are substantially consistent with those contained in PNG’s previous credit facility. This new agreement 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 agreement contains restrictive covenants, including those that restrict PNG’s ability to grant liens, incur additional indebtedness, engage in certain transactions with affiliates, engage in substantially unrelated businesses, sell substantially all of its assets or enter into a merger or consolidation, and enter into certain burdensome agreements. In addition, the credit agreement contains certain financial covenants which, among other things, require PNG to maintain a debt-to-EBITDA coverage ratio that will not be greater than 5.00 to 1.00 on outstanding debt (5.50 to 1.00 during an acquisition period) and also require that PNG maintain an EBITDA-to-interest coverage ratio that will not be less than 3.00 to 1.00, as such terms are defined in the credit agreement.

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. These letters of credit are issued under our PAA senior unsecured revolving credit facility, our senior secured hedged inventory facility and PNG's senior unsecured revolving credit facility, and our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. At December 31, 2011 and 2010, we had outstanding letters of credit of approximately $33 million and $75 million, respectively.

Note 5—Partners' Capital and Distributions

Units Outstanding

Partners' capital at December 31, 2011 consists of 155,376,937 common units outstanding, representing a 98% effective aggregate ownership interest in the Partnership and its subsidiaries after giving effect to the 2% general partner interest.

Distributions

We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter, less reserves established by our general partner for future requirements.

General Partner Incentive Distributions

Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, the general partner is typically entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per unit, referred to as our MQD, 25% of the amounts we distribute in excess of $0.495 per unit and 50% of amounts we distribute in excess of $0.675 per unit (referred to as "incentive distributions").

Per unit cash distributions on our outstanding units and the portion of the distributions representing an excess over the MQD were as follows:

	Year					
	2011		2010		2009	
	Distribution [1]	Excess over MQD	Distribution	Excess over MQD	Distribution	Excess over MQD
First Quarter	$ 0.9575	$ 0.5075	$ 0.9275	$ 0.4775	$ 0.8925	$ 0.4425
Second Quarter	$ 0.9700	$ 0.5200	$ 0.9350	$ 0.4850	$ 0.9050	$ 0.4550
Third Quarter	$ 0.9825	$ 0.5325	$ 0.9425	$ 0.4925	$ 0.9050	$ 0.4550
Fourth Quarter	$ 0.9950	$ 0.5450	$ 0.9500	$ 0.5000	$ 0.9200	$ 0.4700

[1] Distributions represent those declared and paid in the applicable period.

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 of the Pacific acquisition in November 2006, the Rainbow acquisition in May 2008 and the PNGS Acquisition in September 2009, our general partner agreed to reduce the amounts due to it as incentive distributions by a total of $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.

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.

Total cash distributions made were as follows (in millions, except per unit amounts):

	Distributions Paid				Distributions per limited partner unit
	Common Units	General Partner			
Year		Incentive	2%	Total	
2011	$ 575	$ 204	$ 12	$ 791	$ 3.91
2010	$ 512	$ 160	$ 10	$ 682	$ 3.76
2009	$ 468	$ 127	$ 10	$ 605	$ 3.62

On January 10, 2012, we declared a cash distribution of $1.025 per unit on our outstanding common units. The distribution was paid on February 14, 2012 to unitholders of record on February 3, 2012, for the period October 1, 2011 through December 31, 2011. The total distribution paid was approximately $225 million, with approximately $159 million paid to our common unitholders and $3 million and $63 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Noncontrolling Interests in a Subsidiary

As of December 31, 2011, noncontrolling interests in a subsidiary consisted of the following: (i) the approximate 36% interest in PNG and (ii) the 25% interest in SLC Pipeline.

PNG Initial Public Offering

On May 5, 2010, PNG completed its IPO of 13,478,000 common units representing limited partner interests at $21.50 per common unit. The number of units issued at closing included 1,758,000 common units issued pursuant to the full exercise of the underwriters' over-allotment option. Net proceeds received by PNG from the sale of the 13,478,000 common units were approximately $268 million and were used to repay amounts outstanding under our credit facilities and for general partnership purposes. The common units offered represented approximately 23% of the outstanding equity of PNG.

Prior to the PNG IPO, we owned 100% of PNGS' natural gas storage business, the predecessor of PNG, and related operating entities. Immediately prior to the closing of the 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 conjunction with the PNG IPO, we recorded noncontrolling interest of $167 million associated with the book value of PNG sold to the public. We also recorded an increase to our partners' capital of approximately $101 million associated with the net increase from our share of the proceeds received in the offering partially offset by the dilution of our interest in PNG resulting from the IPO.

Series A and Series B Subordinated Units. The Series A subordinated units are not entitled to receive any distributions until the common units have received the MQD ($1.35 on an annualized basis) plus any arrearages in the payment of the MQD from prior quarters. The Series A subordinated units will convert to common units once certain earnings and distribution targets are met for three consecutive, non-overlapping four-quarter periods. The Series B subordinated units are not entitled to participate in quarterly distributions. Instead, the Series B subordinated units convert to Series A subordinated units in distinct tranches upon the achievement of defined benchmarks tied to the amount of capacity in service at Pine Prairie and increases in PNG's quarterly distributions. The Series B subordinated units will convert into Series A subordinated units on a one-for-one basis for each tranche when the respective benchmarks are reached for (i) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service, (ii) the distributable cash flow generated by PNG for two consecutive quarters sufficient to pay a quarterly distribution of at least the annualized distribution benchmark on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and (iii) the quarterly distribution of available cash of at least the annualized distribution benchmark for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG's general partner's 2% interest and the related distributions on the incentive distribution rights.

Modifications of Holdings in and Conversion of PNG Subordinated Units

On August 16, 2010, the Amended and Restated Agreement of Limited Partnership of PNG was amended and restated (the "Second Amended and Restated Agreement") to reduce the number of Series A subordinated units by 2.0 million and increase the number of Series B subordinated units by an equivalent amount. The Second Amended and Restated Agreement also increased the number of potential conversion tranches on Series B subordinated units from three to five. In addition, the terms of the Series B subordinated units were modified to extend the conversion period by raising the operating and financial performance benchmarks of approximately one-third of the Series B subordinated units outstanding prior to this modification. This amendment was intended to increase the distribution coverage and organic growth profile of PNG's common and Series A subordinated units and improve PNG's posture with respect to potential acquisitions. We accounted for this transaction as an exchange between entities under common control and accordingly, we reclassified the book value of the 2.0 million Series A subordinated units at the time of the modification to Series B subordinated units.

The following table sets forth the changes made to our holdings in the limited partner units of PNG as a result of the August 2010 modification (units in millions):

	Prior to Modification	Modification	Post Modification
PNG Units Owned by PAA:			
Common Units	18.1	—	18.1
Series A Subordinated Units	13.9	(2.0)	11.9
Common & Series A Subordinated Unit Subtotal	32.0	(2.0)	30.0
Series B Subordinated Units (Performance Thresholds):			
Tranche 1 ($1.44 / 29.6 Bcf)	4.6	(2.0)	2.6
Tranche 2 ($1.53 / 35.6 Bcf)	3.8	(1.0)	2.8
Tranche 3 ($1.63 / 41.6 Bcf)	3.1	(1.0)	2.1
Tranche 4 ($1.71 / 48.0 Bcf)	—	3.0	3.0
Tranche 5 ($1.80 / 48.0 Bcf)	—	3.0	3.0
Series B Subordinated Unit Subtotal	11.5	2.0	13.5
Total PNG Units Owned by PAA [1]	43.5	—	43.5

[1] See "PNG Transaction Grants" in Note 10.

In February 2012, PNG modified the terms of the first three tranches of the PNG Series B subordinated units held by PAA. The modification increases the quarterly distribution benchmark for the first three of the five tranches to an annualized level of $1.71 per unit.

The following table presents the operational and financial benchmarks, as modified in February 2012 for conversion of the Series B subordinated units into Series A subordinated units for each tranche (units in millions):

	Series B Subordinated Units to Convert into Series A Subordinated Units	Working Gas Storage Capacity (Bcf)	Annualized Distribution Level
Tranche 1	2.6	29.6	$ 1.71
Tranche 2	2.8	35.6	$ 1.71
Tranche 3	2.1	41.6	$ 1.71
Tranche 4	3.0	48.0	$ 1.71
Tranche 5	3.0	48.0	$ 1.80

PNG's general partner will determine whether the in-service operational tests set forth above have been satisfied. To the extent that the operational tests described above are satisfied prior to or during the two-quarter period applicable to the financial tests described above, the holder of the Series B subordinated units subject to conversion will be entitled to receive the quarterly distribution payable with respect to the second quarter of such two-quarter period. In all other circumstances, where the operational tests are satisfied following the two-quarter period applicable to the financial tests, the holder of the Series B subordinated units subject to conversion will be entitled to receive any distribution payable following the satisfaction of such operational tests.

Any Series B subordinated units that remain outstanding as of December 31, 2018 will automatically be cancelled.

Following conversion of any Series B subordinated units into Series A subordinated units, such converted Series B subordinated units will further convert into common units (together with any other outstanding Series A subordinated units) to the extent that the tests for conversion of the Series A subordinated units are satisfied. In determining whether such conversion tests have been satisfied, the Series B subordinated units that have converted into Series A subordinated units will be treated as Series A subordinated units from and after the date of their conversion into Series A subordinated units.

If at the time the above operational and financial tests are satisfied, the subordination period has already ended and all outstanding Series A subordinated units have converted into common units, the Series B subordinated units will instead convert directly into common units on a one-for-one basis and participate in the quarterly distribution payable to common units.

PNG Common Unit Issuance

During February 2011, in connection with the Southern Pines Acquisition, PNG completed a private placement of approximately 17.4 million PNG common units to third-party purchasers for net proceeds of approximately $370 million. In addition, we purchased approximately 10.2 million PNG common units for approximately $230 million, including our proportionate general partner contribution of $12 million (collectively, "the PNG offering"). Also, during May 2011, a portion of the PNG Transaction Grants vested and was settled with 58,672 PNG units, which were owned by us. See Note 10 for further detail. As a result of these transactions, our aggregate ownership interest in PNG decreased from approximately 77% to approximately 64%. The following table sets forth our ownership changes in the limited partner units of PNG from December 31, 2010 to December 31, 2011 (units in millions):

	December 31, 2010	February 2011 PNG Issuance	Transaction Grants	December 31, 2011
PNG Units Owned by PAA:				
Common Units	18.1	10.2	(0.1)	28.2
Series A Subordinated Units	11.9	—	—	11.9
Series B Subordinated Units	13.5	—	—	13.5
Total PNG Units Owned by PAA	43.5	10.2	(0.1)	53.6

In addition to our limited partner interest, we also own the general partner's 2% interest and the incentive distribution rights in PNG.

In conjunction with the PNG offering, we recorded an increase in noncontrolling interest of $306 million and an increase to our partners' capital of approximately $64 million. The increases result from the portion of the proceeds attributable to the respective ownership interests in PNG, adjusted for the impact of the dilution of our ownership interest resulting from the transaction.

Formation of SLC Pipeline LLC

During the fourth quarter of 2008, we completed construction on a 94-mile expansion of the Salt Lake City Area system from Wahsatch, Utah to Salt Lake City. During the first quarter of 2009, this pipeline became fully operational. Pursuant to a master formation agreement, we contributed the pipeline with a book value of approximately $254 million to a newly formed joint venture, SLC Pipeline. Holly Energy Partners-Operating, L.P. ("HEP") contributed approximately $26 million in cash for a 25% ownership in SLC Pipeline. We own the remaining 75% interest in SLC Pipeline and control the joint venture, and therefore, have consolidated the financial results. We recognized a loss in partners' capital of approximately $38 million related to the formation of the SLC Pipeline joint venture during 2009. This loss represented the difference between HEP's contribution of cash and the book value of its 25% interest in the net assets of SLC Pipeline.

Noncontrolling Interests Rollforward

The following table reflects the changes in the noncontrolling interests in partners' capital (in millions):

For the Year Ended December 31,

	2011	2010	2009
Beginning balance	$ 231	$ 63	$ —
Sale of noncontrolling interests in subsidiaries	306	167	64
Net income attributable to noncontrolling interests	28	9	1
Distributions to noncontrolling interests	(40)	(10)	(2)
Equity compensation expense	3	3	—
Net deferred loss on cash flow hedges	(4)	—	—
Other	—	(1)	—
Ending Balance	$ 524	$ 231	$ 63

The following table sets forth the impact upon net income attributable to Plains given effect to the changes in our ownership interest in PNG and SLC Pipeline, which is recognized in partners' capital (in millions):

	Year Ended December 31,		
	2011	2010	2009
Net income attributable to Plains	$ 966	$ 505	$ 579
Transfers to the noncontrolling interests:			
Increase in capital from sale of PNG units	64	101	—
Decrease in capital from sale of interest in SLC Pipeline	—	—	(38)
Change from net income attributable to Plains and net transfers to the noncontrolling interest	$ 1,030	$ 606	$ 541

LTIP Vesting

In connection with the settlement of vested LTIP awards, we issued 242,762 common units during 2011 with a fair value of approximately $15 million.

Equity Offerings

During the three years ended December 31, 2011, we completed the following equity offerings of our common units as shown in the table below (in millions, except unit and per unit data). See "PNGS Acquisition" below for discussion of additional common units issued in 2009 in connection with such acquisition.

Period	Units Issued	Gross Unit Price	Proceeds from Sale	General Partner Contribution	Costs	Net Proceeds
November 2011 [(1)]	6,000,000	$ 65.03	$ 390	$ 9	$ (13)	$ 386
March 2011 [(1)]	7,935,000	$ 64.00	508	10	(15)	503
2011 Total	**13,935,000**		**$ 898**	**$ 19**	**$ (28)**	**$ 889**
November 2010 [(1)]	4,780,000	$ 62.60	$ 299	$ 6	$ (9)	$ 296
2010 Total	**4,780,000**		**$ 299**	**$ 6**	**$ (9)**	**$ 296**
September 2009 [(1)]	5,290,000	$ 46.70	$ 247	$ 5	$ (6)	$ 246
March 2009 [(1)]	5,750,000	$ 36.90	212	4	(6)	210
2009 Total	**11,040,000**		**$ 459**	**$ 9**	**$ (12)**	**$ 456**

[(1)] These offerings of common units were underwritten transactions that required us to pay a gross spread. The net proceeds from these offerings were used to reduce outstanding borrowings under our credit facilities and for general partnership purposes.

PNGS Acquisition

In September 2009, we issued 1,907,305 common units valued at approximately $91 million in order to satisfy a portion of the PNGS Acquisition purchase price. In conjunction with the issuance, we received a contribution from our general partner of approximately $2 million. See Note 3 for further discussion.

Class B Units of Plains AAP, L.P.

In August 2007, the owners of Plains AAP, L.P. authorized the board of directors of Plains All American GP LLC to issue Class B units of Plains AAP, L.P. ("AAP LP Class B units"). At December 31, 2011, approximately 183,500 AAP LP Class B units were outstanding, of which 80,063 had been earned. A total of 16,500 AAP LP Class B units are reserved for future issuances. See Note 10 for further discussion of the AAP LP Class B units.

Note 6—Derivatives and Hedging Instruments

We identify the risks that underlie our core business activities and use risk management strategies to mitigate those risks when we determine that there is value in doing so. Our policy is to use derivative instruments for risk management purposes and not for the purpose of speculating on commodity price changes. We use various derivative instruments to (i) manage our exposure to commodity price risk as well as to optimize our profits, (ii) manage our exposure to interest rate risk and (iii) manage our exposure to currency exchange rate risk. Our commodity risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring NYMEX, ICE and over-the-counter positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity. Our interest rate and currency exchange rate risk management policies and procedures are designed to monitor our positions and ensure that those positions are consistent with our objectives and approved strategies. Our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives used in a transaction are highly effective in offsetting changes in cash flows or the fair value of hedged items.

Commodity Price Risk Hedging

Our core business activities contain certain commodity price-related risks that we manage in various ways, including the use of derivative instruments. Our policy is (i) to only purchase 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 or derivatives for the purpose of speculating on commodity price changes. The material commodity-related risks inherent in our business activities can be summarized into the following general categories:

Commodity Purchases and Sales — In the normal course of our operations, we purchase and sell commodities. We use derivatives to manage the associated risks and to optimize profits. As of December 31, 2011, net derivative positions related to these activities included:

- An approximate 177,300 barrels per day net long position (total of 5.3 million barrels) associated with our crude oil purchases, which was unwound ratably during January 2012 to match monthly average pricing.

- A net short spread position averaging approximately 30,800 barrels per day (total of 10.3 million barrels), which hedges a portion of our anticipated crude oil lease gathering purchases through January 2013. These derivatives are time spreads consisting of offsetting purchases and sales between two different months. Our use of these derivatives does not expose us to outright price risk.

- Approximately 9,200 barrels per day on average (total of 6.7 million barrels) of WTS/WTI crude oil basis swaps through December 2013, which hedge anticipated sales of crude oil (WTI). These derivatives are grade spreads between two different grades of crude oil. Our use of these derivatives does not expose us to outright price risk.

- Approximately 6,000 barrels per day on average (total of 2.2 million barrels) of LLS/WTI crude oil basis swaps January 2012 through December 2012, which hedge anticipated sales of crude oil (LLS). These derivatives are grade spreads between two different grades of crude oil. Our use of these derivatives does not expose us to outright price risk.

- A short swap position of approximately 14.6 Bcf through April 2012 related to anticipated sales of natural gas.

- A long swap position of approximately 0.6 Bcf through April 2013 related to anticipated purchases of natural gas.

Storage Capacity Utilization — We own approximately 80 million barrels of crude oil, LPG and refined products storage capacity other than that used in our transportation operations. This storage may be leased to third parties or utilized in our own supply and logistics activities, including for the storage of inventory in a contango market. For capacity allocated to our supply and logistics operations, we have utilization risk if the market structure is backwardated. As of December 31, 2011, we used derivatives to manage the risk of not utilizing approximately 3.7 million barrels per month of storage capacity through 2012. These positions are a combination of calendar spread options and futures contracts. These positions involve no outright price exposure, but instead represent potential offsetting purchases and sales between time periods (first month versus second month for example).

Inventory Storage — At times, we elect to purchase and store crude oil, LPG and refined products inventory in conjunction with our supply and logistics activities. When we purchase and store inventory, we enter into physical sales contracts or use derivatives to mitigate price risk associated with the inventory. As of December 31, 2011, we had derivatives totaling approximately 5.0 million barrels hedging our inventory. These positions are a combination of futures, swaps and option contracts.

Pipeline Loss Allowance Oil — As is common in the pipeline transportation 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 utilize derivative instruments to hedge a portion of the anticipated sales of the allowance oil that is to be collected under our tariffs. As of December 31, 2011, our PLA hedges included (i) a net short position consisting of crude oil futures and swaps for an average of approximately 1,500 barrels per day (total of 2.2 million barrels) through December 2015, (ii) a long put option position of approximately 0.4 million barrels through December 2012 and (iii) a long call option position of approximately 0.9 million barrels through December 2015.

Base Gas Management — Our gas storage facilities require minimum levels of base gas to operate. For our natural gas storage facilities that are under construction, we anticipate purchasing base gas in future periods as construction is completed. We use derivatives to hedge such anticipated purchases of natural gas. As of December 31, 2011, we have a long swap position of approximately 3.0 Bcf through April 2013 related to anticipated base gas purchases.

All of our commodity derivatives that qualify for hedge accounting are designated as cash flow hedges. We have determined that substantially all of our physical purchase and sale agreements qualify for the NPNS exclusion. Physical commodity contracts that meet the definition of a derivative but are ineligible, or not designated, for the NPNS scope exception are recorded on the balance sheet at fair value, with changes in fair value recognized in earnings.

Interest Rate Risk Hedging

We use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and outstanding debt instruments. The derivative instruments we use to manage this risk consist primarily of interest rate swaps and treasury locks. As of December 31, 2011, AOCI includes deferred losses of $133 million that relate to open and terminated interest rate derivatives that were designated for hedge accounting. The terminated interest rate derivatives were cash-settled in connection with the issuance or refinancing of debt agreements. The deferred gain related to these instruments is being amortized to interest expense over the terms of the hedged debt instruments.

During the second and third quarters of 2011, we entered into forward starting interest rate swaps to hedge the underlying benchmark interest rate related to forecasted debt issuances through 2015. The following table summarizes the terms of our forward starting interest rate swaps (notional amounts in millions):

Hedged Transaction	Number and Types of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Anticipated debt offering	4 forward starting swaps (10-year)	$ 200	6/15/2012	3.46 %	Cash flow hedge
Anticipated debt offering	6 forward starting swaps (30-year)	$ 250	6/17/2013	4.24 %	Cash flow hedge
Anticipated debt offering	2 forward starting swaps (30-year)	$ 50	6/16/2014	3.94 %	Cash flow hedge
Anticipated debt offering	10 forward starting swaps (30-year)	$ 250	6/15/2015	3.60 %	Cash flow hedge

During June 2011 and August 2011, PNG entered into three interest rate swaps to fix the interest rate on a portion of PNG’s outstanding debt. The swaps have an aggregate notional amount of $100 million with an average fixed rate of 0.95%. Two of these swaps terminate in June 2014 and the remaining swap terminates in August 2014. These swaps are designated as cash flow hedges.

Concurrent with our January 2011 senior notes issuance, we terminated three forward starting interest rate swaps. These swaps had an aggregate notional amount of $100 million and an average fixed rate of 3.6%. We received cash proceeds of $12 million associated with the termination of these swaps.

During July 2009, we entered into four interest rate swaps for which we receive fixed interest payments and pay floating-rate interest payments based on three-month LIBOR plus an average spread of 2.42% on a semi-annual basis. The swaps have an aggregate notional amount of $300 million with fixed rates of 4.25%. Two of the swaps terminated in September 2011, and two of the swaps will terminate in September 2012. The swaps that terminate in 2012 are designated as fair value hedges.

Currency Exchange Rate Risk Hedging

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 foreign currency derivatives to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. As of December 31, 2011, AOCI includes net deferred gains of approximately $10 million that relate to open and settled foreign currency derivatives that were designated for hedge accounting. These foreign currency derivatives hedge the cash flow variability associated with CAD-denominated interest payments on CAD-denominated intercompany notes as a result of changes in the exchange rate.

As of December 31, 2011, our outstanding foreign currency derivatives also include derivatives we use to hedge USD-denominated crude oil purchases and sales in Canada. In addition, we may from time to time hedge the commodity price risk associated with a CAD-denominated commodity transaction with a USD-denominated commodity derivative. In conjunction with entering into the commodity derivative, we may enter into a foreign currency derivative to hedge the resulting foreign currency risk. These foreign currency derivatives are generally short-term in nature and are not designated for hedge accounting.

The following table summarizes our open forward exchange contracts that exchange CAD for USD on a net basis (in millions):

	CAD	USD	Average Exchange Rate
2012	$ 15	$ 15	CAD $1.01 to USD $1.00
2013	$ 9	$ 9	CAD $1.00 to USD $1.00

Summary of Financial Impact

For derivatives that qualify as a cash flow hedge, changes in fair value of the effective portion of the hedges are deferred to AOCI and recognized in earnings in the periods during which the underlying physical transactions impact earnings. For our interest rate swaps that qualify as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the underlying hedged item, attributable to the hedged risk, are recognized in earnings each period. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that are not highly effective in offsetting changes in cash flows of the hedged items are recognized in earnings each period. Cash settlements associated with our derivative activities are reflected as operating cash flows in our consolidated statements of cash flows.

A summary of the impact of our derivative activities recognized in earnings for the years ended December 31, 2011 and 2010 is as follows (in millions):

	Year Ended December 31, 2011			Year Ended December 31, 2010		
Location of gain/(loss)	Derivatives in Hedging Relationships (1)(2)(3)(5)	Derivatives Not Designated as a Hedge (4)	Total	Derivatives in Hedging Relationships (1)(2)(3)	Derivatives Not Designated as a Hedge (4)	Total

Commodity Derivatives						
Supply and Logistics segment revenues	$ (161)	$ 99	$ (62)	$ 14	$ 2	$ 16
Transportation segment revenues	—	—	—	2	—	2
Facilities segment revenues	11	—	11	—	—	—
Purchases and related costs	6	—	6	8	(12)	(4)
Field operating costs	—	1	1	—	3	3
Interest Rate Derivatives						
Interest expense	1	—	1	1	2	3
Foreign Exchange Derivatives						
Supply and Logistics segment revenues	—	1	1	—	2	2
Purchases and related costs	—	—	—	—	2	2
Other income/(expense), net	6	—	6	—	(1)	(1)
Total Gain/(Loss) on Derivatives Recognized in Income	**$ (137)**	**$ 101**	**$ (36)**	**$ 25**	**$ (2)**	**$ 23**

[1] Amounts represent derivative gains and losses that were reclassified from AOCI to earnings during the period to coincide with the earnings impact of the respective hedged transaction.

[2] Amounts include losses of approximately $8 million and $1 million for the years ended December 31, 2011 and 2010, respectively, that represent the ineffective portion of our cash flow hedges. These amounts relate to commodity derivatives and were recognized in Supply and Logistics segment revenues during the respective periods.

[3] Interest expense includes net gains of approximately $2 million and approximately $1 million for the years ended December 31, 2011 and 2010, respectively, associated with outstanding interest rate swaps, which are designated as a fair value hedge.

[4] Includes realized and unrealized gains or losses for derivatives not designated for hedge accounting during the period.

[5] Includes unrealized gains of approximately $6 million reclassified from AOCI to earnings during the period to offset a lower of cost or market adjustment relating to the carrying value of PNG's inventory.

The following table summarizes the derivative assets and liabilities on our consolidated balance sheet on a gross basis as of December 31, 2011 (in millions):

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 72	Other current assets	$ (47)
	Other long-term assets	20	Other long-term assets	(2)
Interest rate derivatives	Other current assets	1	Other current liabilities	(24)
			Other long-term liabilities	(114)
Foreign currency derivatives	Other current assets	1		
Total derivatives designated as hedging instruments		$ 94		$ (187)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 87	Other current assets	$ (39)
	Other long-term assets	6	Other long-term assets	(3)
			Other current liabilities	(1)
Total derivatives not designated as hedging instruments		$ 93		$ (43)
Total derivatives		$ 187		$ (230)

The following table summarizes the derivative assets and liabilities on our consolidated balance sheet on a gross basis as of December 31, 2010 (in millions):

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 71	Other current assets	$ (70)
			Other long-term assets	(1)
			Other current liabilities	(1)
Interest rate derivatives	Other current assets	10		
Total derivatives designated as hedging instruments		$ 81		$ (72)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 11	Other current assets	$ (68)
	Other long-term assets	20		
	Other current liabilities	2	Other current liabilities	(10)
Interest rate derivatives	Other current assets	4		
	Other long-term assets	1		
Foreign currency derivatives	Other current assets	1		
Total derivatives not designated as hedging instruments		$ 39		$ (78)
Total derivatives		$ 120		$ (150)

As of December 31, 2011, there was a net loss of approximately $99 million deferred in AOCI, excluding tax effects. The total amount of deferred net loss recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the earnings recognition of the underlying hedged commodity transaction, (ii) interest expense accruals associated with underlying debt instruments or (iii) the recognition of a foreign currency gain or loss upon the remeasurement of certain CAD-denominated intercompany balances. Of the total net loss deferred in AOCI at December 31, 2011, we expect to reclassify a net gain of approximately $21 million to earnings in the next twelve months. Of the remaining deferred loss in AOCI, a net gain of approximately $9 million is expected to be reclassified to earnings prior to 2015 with the remaining deferred loss of $129 million being reclassified to earnings through 2045. These amounts are predominantly based on market prices at the current period end, thus actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

During the year ended December 31, 2011, we reclassified a gain of approximately $2 million from AOCI to earnings as a result of anticipated hedged transactions that are probable of not occurring. During the year ended December 31, 2010, all of our hedged transactions were probable of occurring. The net deferred gain/(loss), excluding tax effects, recognized in AOCI for derivatives during the years ended December 31, 2011 and 2010 are as follows (in millions):

	For the Years Ended December 31,	
	2011	2010
Commodity derivatives, net	$ (15)	$ (82)
Foreign exchange derivatives, net	—	(2)
Interest rate derivatives, net	(136)	8
Total	$ (151)	$ (76)

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting agreement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through brokerage accounts and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of December 31, 2011, we had a net broker payable of approximately $7 million (consisting of initial margin of $52 million reduced by $59 million of variation margin that had been returned to us). As of December 31, 2010, we had a net broker receivable of approximately $99 million (consisting of initial margin of $56 million increased by $43 million of variation margin that had been posted by us). At December 31, 2011 and 2010, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings.

Recurring Fair Value Measurements

Derivative Financial Assets and Liabilities

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2011 and 2010. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which affects the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value as of December 31, 2011 (in millions)				Fair Value as of December 31, 2010 (in millions)			
Recurring Fair Value Measures [(1)]	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Commodity derivatives	$ 80	$ 1	$ 12	$ 93	$ (16)	$ —	$ (30)	$ (46)
Interest rate derivatives	—	(137)	—	(137)	—	—	15	15
Foreign currency derivatives	—	1	—	1	—	—	1	1
Total	$ 80	$ (135)	$ 12	$ (43)	$ (16)	$ —	$ (14)	$ (30)

[1] Derivative assets and liabilities are presented above on a net basis but do not include related cash margin deposits.

The determination of the fair values above includes not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit) but also the impact of our nonperformance risk on our liabilities. The fair value of our commodity derivatives, interest-rate derivatives and foreign currency derivatives includes adjustments for credit risk. Our credit adjustment methodology uses market observable inputs and requires judgment. There were no changes to any of our valuation techniques during the period.

Level 1

Included within level 1 of the fair value hierarchy are exchange-traded commodity derivatives such as futures, options and swaps. The fair value of exchange-traded commodity derivatives is based on unadjusted quoted prices in active markets and is therefore classified within level 1 of the fair value hierarchy.

Level 2

Included within level 2 of the fair value hierarchy are over-the-counter commodity, interest rate and foreign currency derivatives that are traded in active markets. The fair value of these derivatives is based on broker or dealer price quotations which are corroborated with market observable inputs.

Level 3

Included within level 3 of the fair value hierarchy are over-the-counter commodity derivatives that are traded in markets that are active but not sufficiently active to warrant level 2 classification in our judgment and certain physical commodity contracts. The fair value of our level 3 commodity derivatives is based on broker or dealer price quotations or a valuation model. Our valuation models utilize inputs such as forward prices but do not involve significant management judgments.

Rollforward of Level 3 Net Liability

The following table provides a reconciliation of changes in fair value of the beginning and ending balances for our derivatives classified as level 3 (in millions):

	Year Ended December 31,	
	2011	2010
Beginning Balance	$ (14)	$ (28)
Unrealized gains/(losses):		
Included in earnings [1]	17	(22)
Included in other comprehensive income	2	3
Settlements	21	42
Derivatives entered into during the period	3	(9)
Transfers out of level 3	(17)	—
Ending Balance	$ 12	$ (14)
Change in unrealized gains/(losses) included in earnings relating to level 3 derivatives still held at the end of the periods	$ 22	$ (27)

[1] We reported unrealized gains and losses associated with level 3 commodity derivatives in our consolidated statements of operations as Supply and Logistics segment revenues. Gains and losses associated with interest rate derivatives are reported in our consolidated statements of operations as Interest expense. Gains and losses associated with foreign currency derivatives are reported in our consolidated statements of operations as either Supply and Logistics segment revenues, Purchases and related costs, or Other income/(expense), net.

During the first quarter of 2011, we transferred interest rate and commodity derivatives with an aggregate fair value of $17 million from level 3 to level 2. This transfer resulted from the implementation of additional valuation procedures, using market observable inputs, to validate the broker or dealer price quotations used for fair value measurement. Our policy is to recognize transfers between levels as of the beginning of the reporting period in which the transfer occurred.

We believe that a proper analysis of our level 3 gains or losses must incorporate the understanding that these items are generally used to hedge our commodity price risk, interest rate risk and foreign currency exchange risk and will therefore be offset by gains or losses on the underlying transactions.

Note 7—Income Taxes

U.S. Federal and State Taxes

As an MLP, we are not subject to U.S. federal income taxes; rather the tax effect of our operations is passed through to our unitholders. Although we are subject to state income taxes in some states, the impact to the years ended December 31, 2011, 2010, and 2009 was immaterial.

Canadian Federal and Provincial Taxes

In 2010 and prior years, our Canadian operations were operated through a combination of corporate entities subject to Canadian federal and provincial taxes and a limited partnership which was treated as a flow-through entity for tax purposes. Due to changes in Canadian legislation and the Fifth Protocol to the U.S./Canada Tax Treaty, we restructured our Canadian investment on January 1, 2011. As of this date, all of our Canadian operations are conducted within entities that are treated as corporations for Canadian tax purposes (flow through for U.S. tax purposes) and that are subject to Canadian federal and provincial taxes. Additionally, payments of interest and dividends from Canada to other Plains entities are subject to Canadian withholding tax that is treated as income tax expense.

Tax Components

Components of income tax expense are as follows (in millions):

	Year Ended December 31,		
	2011	**2010**	**2009**
Current tax (benefit)/expense:			
State income tax	$ 2	$ 1	$ 2
Canadian federal and provincial income tax	36	(2)	13
Total current tax (benefit)/ expense	$ 38	$ (1)	$ 15
Deferred tax (benefit)/expense:			
State income tax	$ (2)	$ 1	$ —
Canadian federal and provincial income tax	9	(1)	(9)
Total deferred tax (benefit)/expense	$ 7	$ —	$ (9)
Total income tax (benefit)/expense	$ 45	$ (1)	$ 6

The difference between tax expense based on the statutory federal income tax rate and our effective tax expense is summarized as follows (in millions):

	Year Ended December 31,		
	2011	**2010**	**2009**
Income before tax	$ 1,039	$ 513	$ 586
Partnership earnings not subject to current Canadian tax	(909)	(509)	(585)
	$ 130	$ 4	$ 1
Canadian federal and provincial corporate tax rate	27%	28%	29%
Income tax at statutory rate	$ 35	$ 1	$ —
Current tax (benefit)/expense:			
Canadian withholding tax	$ 12	$ —	$ —
Canadian period tax as a result of book versus tax differences	(9)	—	4
Canadian permanent differences between book and tax	(2)	(3)	9
State income tax	2	1	2
Current income tax (benefit)/expense	$ 38	$ (1)	$ 15
Deferred tax expense:			
State deferred income tax	$ (2)	$ 1	$ —
Canadian deferred tax (benefit)/expense as a result of book versus tax differences	9	(1)	(9)
Deferred income tax (benefit)/expense	$ 7	$ —	$ (9)
Total income tax (benefit)/expense	$ 45	$ (1)	$ 6

Deferred tax assets and liabilities, which are included net within other long-term liabilities and deferred credits in our consolidated balance sheet, result from the following (in millions):

	December 31,	
	2011	**2010**
Deferred tax assets:		
Book accruals in excess of current tax deductions	$ 18	$ 4
Total deferred tax assets	18	4
Deferred tax liabilities:		
Property, plant and equipment in excess of tax values	(147)	(128)
Total deferred tax liabilities	(147)	(128)
Net deferred tax liabilities	$ (129)	$ (124)

Generally, tax returns for our Canadian entities are open to audit from 2007 through 2011. Our U.S. and state tax years are generally open to examination from 2008 to 2011.

Note 8—Major Customers and Concentration of Credit Risk

Marathon Petroleum Corporation and its affiliates accounted for 16%, 14% and 14% of our revenues for each of the three years ended December 31, 2011, 2010 and 2009, respectively. ConocoPhillips Company accounted for 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. 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.

Financial instruments that potentially subject us to concentrations of credit risk consist principally of trade receivables. Our accounts receivable are primarily from purchasers and shippers of crude oil. This industry concentration has the potential to impact our overall exposure to credit risk in that the customers may be similarly affected by changes in economic, industry or other conditions. We review credit exposure and financial information of our counterparties and generally require letters of credit for receivables from customers that are not considered creditworthy, unless the credit risk can otherwise be reduced. See Note 2 for additional discussion of our accounts receivable and our review of credit exposure.

Note 9—Related Party Transactions

Reimbursement of Expenses of Our General Partner and its Affiliates

We do not pay our general partner a management fee, but we do reimburse our general partner for all direct and indirect costs of services provided to us or incurred on our behalf, including the costs of employee, officer and director compensation and benefits allocable to us as well as all other expenses necessary or appropriate to the conduct of our business (other than expenses related to grants of AAP LP Class B units). 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. Total costs reimbursed by us to our general partner for the years ended December 31, 2011, 2010 and 2009 were $419 million, $374 million and $328 million, respectively.

Vulcan Energy Corporation

In December 2010, Vulcan Energy Corporation sold its 50.1% ownership interest in our general partner. Substantially all of the interest sold was acquired by existing owners of our general partner or their affiliates.

Occidental Petroleum Corporation

As of December 31, 2011, a subsidiary of Occidental Petroleum Corporation ("Oxy") owned approximately 35% of our general partner interest and had a representative on the board of directors of Plains All American GP LLC. During the three years ended December 31, 2011, we recognized sales and transportation storage revenues and purchased petroleum products from companies affiliated with Oxy. These transactions were conducted at posted tariff rates or prices that we believe approximate market. See detail below (in millions):

	For the Year Ended December 31,		
	2011	2010	2009
Revenues	$ 2,568	$ 2,189	$ 181
Purchases and related costs	$ 361	$ 221	$ 164

We currently have a netting arrangement with Oxy. Our gross receivable and payable amounts with affiliates of Oxy were as follows (in millions):

	At December 31,	
	2011	2010
Trade accounts receivable and other receivables	$ 132	$ 379
Accounts payable	$ 155	$ 124

Other

We also have transactions with companies in which we hold an investment accounted for under the equity method of accounting (see Note 2 for information related to these investments). During the three years ended December 31, 2011, we utilized transportation services provided by these companies. Costs related to these services totaled approximately $33 million, $36 million and $34 million for the years ended December 31, 2011, 2010 and 2009, respectively. Accounts payable at December 31, 2011 and 2010 were approximately $5 million and $3 million, respectively. These transactions were conducted at posted tariff rates or contracted rates that we believe approximate market rates.

Note 10—Equity Compensation Plans

PAA Long-Term Incentive Plan Awards

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the "1998 Plan"), the 2005 Long-Term Incentive Plan (the "2005 Plan") and the PPX Successor Long-Term Incentive Plan (the "PPX Successor Plan") for employees and directors, as well as the Plains All American GP LLC 2006 Long-Term Incentive Tracking Unit Plan (the "2006 Plan") for non-officer employees. The 1998 Plan, 2005 Plan and PPX Successor Plan authorize the issuance of an aggregate of 5.4 million common units deliverable upon vesting. Although other types of awards are contemplated under the plans, currently outstanding awards are limited to "phantom units," which mature into the right to receive common units of PAA (or cash equivalent) upon vesting. Some awards also include distribution equivalent rights ("DERs"). Subject to applicable vesting criteria, a DER entitles the grantee to a cash payment equal to the cash distribution paid on an outstanding common unit. The 2006 Plan authorizes the grant of approximately 2.1 million "tracking units" which, upon vesting, represent the right to receive a cash payment in an amount based upon the market value of a common unit at the time of vesting. Our general partner is entitled to reimbursement by us for any costs incurred in settling obligations under the plans.

At December 31, 2011, the following LTIP awards, denominated in PAA units, were outstanding (units in millions):

LTIP Units Outstanding	PAA Distribution Required	Estimated Unit Vesting Date				
		2012	2013	2014	2015	Thereafter
2.6[1]	$3.75 - $4.45	0.9	0.6	0.5	0.6	—
1.4[2]	$3.80 - $4.25	0.6	0.5	0.2	0.1	—
4.0[3] [4]		1.5	1.1	0.7	0.7	—

[1] These LTIP awards have performance conditions requiring the attainment of an annualized PAA distribution of between $3.75 and $4.45 and vest upon the later of a certain date or the attainment of such levels. If the performance conditions are not attained while the grantee remains employed by us, or the grantee does not meet employment requirements, these awards will be forfeited. For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

[2] These LTIP awards have performance conditions requiring the attainment of an annualized PAA distribution of between $3.80 and $4.25. For these LTIP awards, fifty percent will vest at specified dates regardless of whether the performance conditions are attained. For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

[3] Approximately 2.2 million of the 4.0 million outstanding PAA LTIP awards also include DERs, of which 1.7 million had vested as of December 31, 2011.

[4] LTIP units outstanding do not include Class B units of Plains AAP, L.P. ("AAP LP Class B units") described below.

Class B Units of Plains AAP, L.P.

In August 2007, the owners of Plains AAP, L.P. authorized the issuance of up to 200,000 AAP LP Class B Units. AAP LP Class B units become earned in various increments upon the achievement of PAA distribution levels of between $3.50 and $4.80 (or in some cases, within 180 days thereof). When earned, the AAP LP Class B unit awards are entitled to participate in distributions paid by Plains AAP, L.P. in excess of $11 million (as adjusted for debt service costs and excluding special distributions funded by debt) per quarter. Assuming all 200,000 AAP LP Class B units were granted and earned, the maximum participation would be 8% of Plains AAP, L.P.'s distribution in excess of $11 million (as adjusted) each quarter. The following table contains a summary of AAP LP Class B unit awards:

	Reserved for Future Grants	Outstanding	Outstanding Units Earned	Grant Date Fair Value Of Outstanding Class B Units [1] (in millions)
Balance as of December 31, 2010	24,500	175,500	80,063	$ 40
Class B unit issuances	(8,000)	8,000	—	4
Class B unit forfeitures	—	—	—	—
Class B units earned	—	—	—	—
Balance as of December 31, 2011	16,500	183,500	80,063	$ 44

[1] Of the grant date fair value, approximately $9 million was recognized as expense during both years ended December 31, 2011 and 2010.

Although the entire economic burden of the AAP LP Class B units, which are equity classified, is borne solely by Plains AAP, L.P. and does not impact our cash or units outstanding, the intent of the AAP LP Class B units is to provide a performance incentive and encourage retention for certain members of our senior management. Therefore, we recognize the grant date fair value of the AAP LP 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.

PNG Long-Term Incentive Plan Awards

During April 2010, PNG's general partner adopted the PAA Natural Gas Storage, L.P. 2010 Long Term Incentive Plan (the "PNG Plan") for employees, directors and consultants. The PNG Plan limits the number of PNG common units that may be delivered pursuant to awards under the plan to 3 million units. Although other types of awards are contemplated under the plan, currently outstanding awards are limited to phantom units, which mature into the right to receive common units of PNG (or cash equivalent) upon vesting. Some awards also include DERs.

At December 31, 2011, the following LTIP awards, denominated in PNG units, were outstanding (units in millions):

LTIP Units Outstanding	PNG Distribution Required	Estimated Unit Vesting Date				
		2012	2013	2014	2015	Thereafter
0.3[1]	$1.55 - $1.90	—	—	—	0.1	0.2
0.2[2]	Other	—	0.1	0.1	—	—
0.5[3] [4]		—	0.1	0.1	0.1	0.2

[1] These LTIP awards have performance conditions requiring the attainment of an annualized PNG distribution of between $1.55 and $1.90 and vest upon the later of a certain date or the attainment of such levels. For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

[2] These LTIP awards have performance conditions requiring the conversion of PNG's Series A and Series B subordinated units (see Note 5). For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

[3] Approximately 0.3 million of the 0.5 million outstanding PNG LTIP awards also include DERs, of which less than 0.1 million had vested as of December 31, 2011.

[4] LTIP units outstanding do not include the PNG Transaction Grants or Class B units of PNGS GP LLC described below.

PNG Long-term Incentive Plan Award Modification. On February 2, 2012, the Board of Directors of PNG's general partner approved the modification of certain awards previously granted under the PNG Plan. As a result of the modification, approximately 232,500 equity-classified phantom unit awards will now vest in the following manner: (i) approximately 70,000 awards, with distribution equivalent rights also modified to begin payment in February 2012, will vest upon the date PNG pays an annualized distribution of at least $1.45, (ii) approximately 70,000 awards, with distribution equivalent rights also modified to begin payment in May 2013, will vest upon the date PNG pays an annualized distribution of at least $1.50 and (ii) the remainder, with distribution equivalent rights also modified to begin payment in May 2014, will vest upon the date PNG pays an annualized distribution of at least $1.55. Fifty percent of any awards that have not vested as of the November 2016 distribution date will vest at that time and the remainder will expire. Additionally, 232,500 of equity-classified phantom unit awards with vesting terms originally tied to the conversion of PNG's Series A and Series B subordinated units were modified such that all these awards will now fully vest upon conversion of the Series A subordinated units to common units. Distribution equivalent rights were also granted with respect to these awards beginning February 2012. There was no financial impact at the time of the modification; however, we anticipate that we will recognize additional equity compensation expense in the future as a result of the modification.

PNG Transaction Grants

During September 2010, we entered into agreements with certain of our officers, pursuant to which these officers acquired an aggregate of 375,000 phantom common units, phantom Series A subordinated units, and phantom Series B subordinated units representing a portion of the limited partner interests of PNG issued to us in the PNG IPO. The awards, referred to herein as "PNG Transaction Grants," will vest upon the completion of the service period and certain performance conditions, including the conversion of PNG's Series A subordinated units into common units of PNG and the conversion of PNG's Series B subordinated units into Series A subordinated units of PNG. Upon vesting, these awards will be settled with outstanding common or Series A subordinated units of PNG currently owned by us, resulting in a dilution of our interest in PNG. As of December 31, 2011, 62,500 PNG Transaction Grants had vested in common units.

Class B Units of PNGS GP LLC

During July 2010, the Board of Directors of PNG's general partner authorized the issuance of 165,000 Class B units of PNGS GP LLC ("PNGS GP LLC Class B units"). During 2011, 16,500 PNGS GP LLC Class B units were forfeited. As of December 31, 2011, 74,250 units were outstanding, and the remaining 90,750 units are reserved for future grants. The PNGS GP LLC Class B units earn the right to participate in distributions (i.e. become "earned") in 25% increments 180 days following annualized PNG distribution levels of $2.00, $2.30, $2.50 and $2.70. In addition, 50% of the applicable earned units vest immediately upon becoming earned units and the remaining 50% vest on the fifth anniversary of the date of grant. If PNGS GP LLC Class B units become earned units after the fifth anniversary of the date of grant, 100% of such units will vest immediately upon becoming earned units. When earned, the PNGS GP LLC Class B units participate in quarterly distributions paid to PNG's general partner to the extent such distributions exceed $2.5 million per quarter. Assuming all 165,000 PNGS GP LLC Class B units were granted and earned, the maximum participation rate would be 6% of PNG's quarterly general partner distribution in excess of $2.5 million. As the PNG distribution levels required for vesting are not currently considered to be probable of occurring, no expense was recognized for the PNGS GP LLC Class B Units during the year ended December 31, 2011.

Other Consolidated Equity Compensation Information

Our LTIP awards include both liability classified and equity classified awards. In accordance with FASB guidance regarding share-based payments, the fair value of our liability classified LTIP awards is calculated based on the closing market price of the underlying PAA or PNG units at each balance sheet date and adjusted for the present value of any distributions that are estimated to occur on the underlying units over the vesting period that will not be received by the award recipients. The fair value of our equity classified LTIP awards is calculated based on the closing market price of the PAA or PNG units on the respective grant dates and adjusted for the present value of any distributions that are estimated to occur on the underlying units over the vesting period that will not be received by the award recipient. This fair value is recognized as compensation expense over the service period.

Our LTIP awards typically contain performance conditions based on the attainment of certain annualized distribution levels and vest upon the later of a certain date or the attainment of such 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 obligation associated with these awards up to the level it would be as if we had been accruing for these awards since the grant date. Our DER awards typically contain performance conditions based on the attainment of certain annualized distribution levels and become earned upon the attainment of such levels. The DERs terminate with the vesting or forfeiture of the underlying LTIP award. For liability classified awards, we recognize DER payments in the period the payment is earned as compensation expense. For equity classified awards, we recognize DER payments in the period it is paid as a reduction of partners' capital.

Prior to PNG's IPO and adoption of the PNG Plan, certain PNG officers and other individuals were granted LTIP awards under the PAA LTIP Plans. In connection with the adoption of the PNG plan, substantially all of the then outstanding PAA LTIP awards held by PNG officers were converted to PNG LTIP awards. We recognized incremental compensation expense of less than $1 million during the twelve months ended December 31, 2010 as a result of this modification.

Our accrued liability at December 31, 2011 related to all outstanding liability-classified LTIP awards and DERs is approximately $138 million. This liability includes accruals associated with our assessments that the following performance conditions are probable of occurring: (i) an annualized PAA distribution of $4.35, (ii) an annualized PNG distribution of $1.45 and (iii) the conversion of PNG's Series A subordinated units and the first tranche of PNG's Series B subordinated units. At December 31, 2010, the accrued liability was approximately $102 million, which includes accruals associated with our assessments that the following performance conditions were probable of occurring: (i) an annualized PAA distribution of $4.00, (ii) an annualized PNG distribution of $1.45 and (iii) the conversion of PNG's Series A subordinated units and the first tranche of PNG's Series B subordinated units. In February 2012, the performance conditions related to PNG's Series B subordinated units were modified. See "PNG Long- Term Incentive Plan Award Modification" above for further discussion.

Our equity compensation activity for awards denominated in PAA and PNG units is summarized in the following table (units in millions):

	PAA Units [1]			PNG Units [2][3]		
	Units		Weighted Average Grant Date Fair Value per Unit	Units		Weighted Average Grant Date Fair Value per Unit
Outstanding, December 31, 2008	3.9	$	36.44	—	$	—
Granted	0.6	$	32.20	—	$	—
Vested	(0.6)	$	34.55	—	$	—
Cancelled or forfeited	(0.1)	$	37.82	—	$	—
Acquired	0.1	$	26.24	—	$	—
Outstanding, December 31, 2009	3.9	$	36.40	—	$	—
Granted	2.0	$	45.66	1.1	$	20.49
Vested	(1.1)	$	32.20	—	$	—
Cancelled or forfeited	(0.4)	$	35.62	(0.1)	$	19.22
Outstanding, December 31, 2010	4.4	$	41.69	1.0	$	20.55
Granted	0.5	$	55.05	—	$	—
Vested	(0.7)	$	40.68	(0.1)	$	23.62
Cancelled or forfeited	(0.2)	$	41.97	(0.1)	$	19.20
Outstanding, December 31, 2011	4.0	$	43.53	0.8	$	20.55

[1] Amounts do not include Class B units of Plains AAP, L.P. as discussed above.
[2] Amounts do not include Class B units of PNGS GP LLC as discussed above.
[3] Amounts include PNG Transaction Grants.

We refer to our LTIP Plans, PNG Transaction Grants, AAP LP Class B units and PNGS GP LLC Class B units collectively as "Equity compensation plans." The table below summarizes the expense recognized and the value of vesting (settled both in units and cash) related to our equity compensation plans (in millions):

	2011		2010		2009	
Equity compensation expense	$	110	$	98	$	68
LTIP unit settled vestings [1]	$	24	$	26	$	19
LTIP cash settled vestings	$	19	$	36	$	8
DER cash payments	$	4	$	4	$	4

[1] For the year ended December 31, 2011, approximately $2 million relates to unit vestings which were settled with PNG units.

Approximately 0.2 million, 0.3 million, and 0.3 million PAA units were issued net of tax withholding of approximately 0.1 million, 0.2 million and 0.2 million units, in 2011, 2010, and 2009 respectively, in connection with the settlement of vested awards. The remaining 0.4 million, 0.6 million and 0.1 million of awards that vested during 2011, 2010 and 2009 respectively, were settled in cash. Based on the December 31, 2011 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately $90 million of additional expense over the life of our outstanding awards related to the remaining unrecognized fair value. Actual amounts may differ materially as a result of a change in the market price of our units and/or probability assessments regarding future distributions. We estimate that the remaining fair value will be recognized in expense as shown below (in millions):

Year		Equity Compensation Plan Fair Value Amortization [1] [2]
2012	$	50
2013		26
2014		11
2015		3
2016		—
Total	$	90

[1] Amounts do not include fair value associated with awards containing performance conditions that are not considered to be probable of occurring at December 31, 2011.

[2] Includes unamortized fair value associated with AAP LP Class B units, PNGS GP LLC Class B units and PNG Transaction Grants.

Note 11—Commitments and Contingencies

Commitments

We have commitments, some of which are leases, related to real property, equipment and operating facilities. We also incur costs associated with leased land, rights-of-way, permits and regulatory fees. Future non-cancelable commitments related to these items at December 31, 2011, are summarized below (in millions):

	2012	2013	2014	2015	2016	Thereafter	Total
Leases [1]	$ 71	$ 55	$ 47	$ 41	$ 33	$ 292	$ 539
Other commitments [2]	34	21	19	15	11	47	147
Total	$ 105	$ 76	$ 66	$ 56	$ 44	$ 339	$ 686

[1] Includes capital and operating leases as defined by the FASB guidance.

[2] Primarily includes third-party storage and transportation agreements and pipeline throughput agreements.

Expenditures related to leases for 2011, 2010 and 2009 were $60 million, $52 million and $55 million, respectively.

Litigation

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 the Environmental Protection Agency ("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 LLC ("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 was $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.

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 Energy Resources Conservation Board ("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.

Environmental Remediation

We currently own or lease, and in the past have owned and 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.

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 TNM pipeline assets from Link in 2004, we identified a number of environmental liabilities for which we received a purchase price reduction from Link and recorded a total environmental reserve of $20 million, 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 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.

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.

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 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.

Note 12—Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total [1]
	(in millions, except per unit data)				
2011					
Revenues	$ 7,694	$ 8,859	$ 8,837	$ 8,884	$ 34,275
Gross margin [2]	$ 355	$ 371	$ 413	$ 453	$ 1,592
Operating income	$ 285	$ 298	$ 357	$ 359	$ 1,298
Net income	$ 185	$ 233	$ 288	$ 288	$ 994
Net income attributable to Plains	$ 182	$ 225	$ 281	$ 278	$ 966
Basic net income per limited partner unit	$ 0.90	$ 1.14	$ 1.48	$ 1.38	$ 4.91
Diluted net income per limited partner unit	$ 0.90	$ 1.13	$ 1.47	$ 1.37	$ 4.88
Cash distributions per common unit [3]	$ 0.9575	$ 0.9700	$ 0.9825	$ 0.9950	$ 3.91
2010					
Revenues	$ 6,125	$ 6,124	$ 6,414	$ 7,231	$ 25,893
Gross margin [2]	$ 273	$ 248	$ 206	$ 300	$ 1,027
Operating income	$ 211	$ 192	$ 150	$ 213	$ 767
Net income	$ 151	$ 133	$ 84	$ 146	$ 514
Net income attributable to Plains	$ 151	$ 131	$ 81	$ 142	$ 505
Basic net income per limited partner unit	$ 0.80	$ 0.65	$ 0.28	$ 0.68	$ 2.41
Diluted net income per limited partner unit	$ 0.80	$ 0.65	$ 0.28	$ 0.67	$ 2.40
Cash distributions per common unit [3]	$ 0.9275	$ 0.9350	$ 0.9425	$ 0.9500	$ 3.76

[1] The sum of the four quarters may not equal the total year due to rounding.

[2] Gross margin is calculated as Total revenues less (i) Purchases and related costs, (ii) Field operating costs and (iii) Depreciation and amortization.

[3] Represents cash distributions declared and paid in the applicable period.

Note 13—Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See “Revenue Recognition” within Note 2 for a summary of the types of products and services from which each segment derives its revenues.

Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. We define segment profit as revenues and equity earnings in unconsolidated entities less (i) purchases and related costs, (ii) field operating costs and (iii) segment general and administrative (“G&A”) expenses. Each of the items above excludes depreciation and amortization.

As an MLP, we make quarterly distributions of our “available cash” (as defined in our partnership agreement) to our unitholders. We look at each period’s earnings before non-cash depreciation and amortization as an important measure of segment performance. The exclusion of depreciation and amortization expense could be viewed as limiting the usefulness of segment profit as a performance measure because it does not account in current periods for the implied reduction in value of our capital assets, such as crude oil pipelines and facilities, caused by age-related decline and wear and tear. We compensate for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance investments, which acts to partially offset the aging and wear and tear in the value of our principal fixed assets. These maintenance investments are a component of field operating costs included in segment profit or in maintenance capital, depending on the nature of the cost. Maintenance capital, which is deducted in determining “available cash,” consists of capital expenditures 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. Capital expenditures made to expand the existing earnings capacity of our assets are considered expansion capital expenditures, not maintenance capital. Repair and maintenance expenditures incurred in order to maintain the day to day operation of our existing assets are charged to expense as incurred. The following table reflects certain financial data for each segment for the periods indicated (in millions):

	Transportation	Facilities	Supply & Logistics	Total

Twelve Months Ended December 31, 2011				
Revenues:				
External Customers	$ 572	$ 638	$ 33,065	$ 34,275
Intersegment [1]	593	158	3	754
Total revenues of reportable segments	$ 1,165	$ 796	$ 33,068	$ 35,029
Equity earnings in unconsolidated entities	$ 13	$ —	$ —	$ 13
Segment profit [2] [3]	$ 555	$ 358	$ 647	$ 1,560
Capital expenditures [4]	$ 600	$ 1,317	$ 18	$ 1,935
Total assets	$ 5,156	$ 4,506	$ 5,719	$ 15,381
Maintenance capital	$ 86	$ 22	$ 12	$ 120
Twelve Months Ended December 31, 2010				
Revenues:				
External Customers	$ 565	$ 339	$ 24,989	$ 25,893
Intersegment [1]	480	151	1	632
Total revenues of reportable segments	$ 1,045	$ 490	$ 24,990	$ 26,525
Equity earnings in unconsolidated entities	$ 3	$ —	$ —	$ 3
Segment profit [2] [3]	$ 516	$ 270	$ 240	$ 1,026
Capital expenditures	$ 329	$ 270	$ 163	$ 762
Total assets	$ 4,701	$ 3,303	$ 5,699	$ 13,703
Maintenance capital	$ 67	$ 17	$ 9	$ 93
Twelve Months Ended December 31, 2009				
Revenues:				
External Customers	$ 536	$ 227	$ 17,757	$ 18,520
Intersegment [1]	425	135	2	562
Total revenues of reportable segments	$ 961	$ 362	$ 17,759	$ 19,082
Equity earnings in unconsolidated entities	$ 7	$ 8	$ —	$ 15
Segment profit [2] [3]	$ 477	$ 208	$ 345	$ 1,030
Capital expenditures	$ 183	$ 564	$ 10	$ 757
Total assets	$ 4,468	$ 3,097	$ 4,793	$ 12,358
Maintenance capital	$ 57	$ 16	$ 8	$ 81

[1] Segment revenues and purchases and related costs include intersegment amounts. Intersegment sales are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates.

[2] Supply and logistics segment profit includes interest expense (related to hedged inventory purchases) of $20 million, $17 million and $11 million for the years ended December 31, 2011, 2010 and 2009, respectively.

[3] The following table reconciles segment profit to net income attributable to Plains (in millions):

	Year Ended December 31,		
	2011	2010	2009
Segment profit	$ 1,560	$ 1,026	$ 1,030
Depreciation and amortization	(249)	(256)	(236)
Interest expense	(253)	(248)	(224)
Other income/(expense), net	(19)	(9)	16
Income tax benefit/(expense)	(45)	1	(6)
Net income	994	514	580
Less: Net income attributable to noncontrolling interests	(28)	(9)	(1)
Net income attributable to Plains	$ 966	$ 505	$ 579

[4] Facilities segment capital expenditures includes a cash deposit of $50 million (reflected within “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. Upon completion of this acquisition, we will allocate the assets to our segments, which may result in a different allocation than reflected above. See Note 3 for further discussion of the pending BP NGL acquisition.

Geographic Data

We have operations in the United States and Canada. Set forth below are revenues and long-lived assets attributable to these geographic areas (in millions):

	For the Year Ended December 31,		
Revenues [1]	2011	2010	2009
United States	$ 28,181	$ 21,471	$ 15,439
Canada	6,094	4,422	3,081
	$ 34,275	$ 25,893	$ 18,520

[1] Revenues are primarily attributed to each region based on where the services are provided or the product is shipped.

Long-Lived Assets [1]	As of December 31, 2011	As of December 31, 2010
United States	$ 9,127	$ 7,502
Canada	1,883	1,800
	$ 11,010	$ 9,302

[1] Excludes long-term derivative assets.

EXHIBIT INDEX

2.1 †* — Share Purchase Agreement dated December 1, 2011 by and among Amoco Canada International Holdings B.V. and Plains Midstream Canada ULC (the schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K).

3.1 — Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 27, 2001).

3.2 — Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).

3.3 — Amendment No. 2 dated November 15, 2006 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 21, 2006).

3.4 — Amendment No. 3 dated August 16, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 22, 2007).

3.5 — Amendment No. 4 effective as of January 1, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed April 15, 2008).

3.6 — Amendment No. 5 dated May 28, 2008 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed May 30, 2008).

3.7 — Amendment No. 6 dated September 3, 2009 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 3, 2009).

3.8 — Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).

3.9 — Amendment No. 1 dated December 31, 2010 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.9 to the Annual Report on Form 10-K for the year ended December 31, 2010).

3.10 — Amendment No. 2 dated January 1, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2010).

3.11 — Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).

3.12 — Fifth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated December 23, 2010 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed December 30, 2010).

3.13 — Sixth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated December 23, 2010 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed December 30, 2010).

3.14 — Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).

3.15 — Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).

3.16 — Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed January 4, 2008).

4.1 — Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).

4.2 — First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).

4.3 — Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003).

4.4 — Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).

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

4.6 — Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006).

4.7 — Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).

4.8 — Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).

4.9 — Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 23, 2008).

4.10 — Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 20, 2009).

4.11 — Sixteenth Supplemental Indenture (4.25% Senior Notes due 2012) dated July 23, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 23, 2009).

4.12 — Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed September 4, 2009).

4.13 — Eighteenth Supplemental Indenture (3.95% Senior Notes due 2015) dated July 14, 2010 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 13, 2010).

4.14 — Nineteenth Supplemental Indenture (5.00% Senior Notes due 2021) dated January 14, 2011 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed January 11, 2011).

4.15 — Registration Rights Agreement dated September 3, 2009 by and between Plains All American Pipeline, L.P. and Vulcan Gas Storage LLC (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-3, File No. 333-162477).

10.1 — Credit Agreement dated as of August 19, 2011 among Plains All American Pipeline, L.P., as Borrower; certain subsidiaries of Plains All American Pipeline, L.P. from time to time party thereto, as Designated Borrowers; Bank of America, N.A., as Administrative Agent; and the other Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 25, 2011).

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

10.3 — Amended and Restated Omnibus Agreement dated as of July 23, 2004, among Plains Resources Inc., Plains All American

Pipeline, L.P., Plains Marketing, L.P., Plains Pipeline, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).

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

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

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

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

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

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

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

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

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

10.13 — Transportation Agreement dated July 30, 1993, between All American Pipeline Company and Exxon Company, U.S.A. (incorporated by reference to Exhibit 10.9 to the Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).

10.14 — Transportation Agreement dated August 2, 1993, among All American Pipeline Company, Texaco Trading and Transportation Inc., Chevron U.S.A. and Sun Operating Limited Partnership (incorporated by reference to Exhibit 10.10 to the Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).

10.15 — First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to the Annual Report on Form 10-K for the year ended December 31, 1998).

10.16 — Agreement for Purchase and Sale of Membership Interest in Scurlock Permian LLC between Marathon Ashland LLC and Plains Marketing, L.P. dated as of March 17, 1999 (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 1998).

10.17** — PMC (Nova Scotia) Company Bonus Program (incorporated by reference to Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2004).

10.18** — Quarterly Bonus Program Summary (incorporated by reference to Exhibit 10.21 to the Annual Report on Form 10-K for the year ended December 31, 2005).

10.19** — Form of LTIP Grant Letter (independent directors) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed February 23, 2005).

10.20** — Form of LTIP Grant Letter (designated directors) (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed February 23, 2005).

10.21 — Membership Interest Purchase Agreement by and between Sempra Energy Trading Corporation and PAA/Vulcan Gas Storage, LLC dated August 19, 2005 (incorporated by reference to Exhibit 1.2 to the Current Report on Form 8-K filed September 19, 2005).

10.22** — Waiver Agreement dated as of December 23, 2010 between Plains All American GP LLC and Greg L. Armstrong (incorporated by reference to Exhibit 10.31 to the Annual Report on Form 10-K for the year ended December 31, 2010).

10.23** — Waiver Agreement dated as of December 23, 2010 between Plains All American GP LLC and Harry N. Pefanis (incorporated by reference to Exhibit 10.32 to the Annual Report on Form 10-K for the year ended December 31, 2010).

10.24 — Excess Voting Rights Agreement dated as of August 12, 2005 between Vulcan Energy GP Holdings Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed August 16, 2005).

10.25 — Excess Voting Rights Agreement dated as of August 12, 2005 between Lynx Holdings I, LLC and Plains All American GP LLC (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed August 16, 2005).

10.26** — Employment Agreement between Plains All American GP LLC and John P. vonBerg dated December 18, 2001 (incorporated by reference to Exhibit 10.40 to the Annual Report on Form 10-K for the year ended December 31, 2005).

10.27** — Form of LTIP Grant Letter (audit committee members) (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 23, 2006).

10.28** — Plains All American PPX Successor Long-Term Incentive Plan (incorporated by reference to Exhibit 10.45 to the Annual Report on Form 10-K for the year ended December 31, 2006).

10.29** — Forms of LTIP Grant Letters dated February 22, 2007 (Named Executive Officers) (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2007).

10.30** — Form of Plains AAP, L.P. Class B Restricted Units Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 4, 2008).

10.31 — Third Amended and Restated Credit Agreement dated as of August 19, 2011 by and among Plains Marketing, L.P., as Borrower, Plains All American Pipeline, L.P., as Guarantor, Bank of America, N.A., as Administrative Agent, and the other Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 25, 2011).

10.32 — Contribution and Assumption Agreement dated December 28, 2007, by and between Plains AAP, L.P. and PAA GP LLC (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed January 4, 2008).

10.33** — First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Greg L. Armstrong (incorporated by reference to Exhibit 10.49 to the Annual Report on Form 10-K for the year ended December 31, 2008).

10.34** — First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Harry N. Pefanis (incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the year ended December 31, 2008).

10.35** — First Amendment to Plains All American GP LLC 2005 Long-Term Incentive Plan dated December 4, 2008 (incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K for the year ended December 31, 2008).

10.36** — Second Amendment to Plains All American GP LLC 1998 Long-Term Incentive Plan dated December 4, 2008 (incorporated by reference to Exhibit 10.52 to the Annual Report on Form 10-K for the year ended December 31, 2008).

10.37** — Form of Amendment to LTIP grant letters (executive officers) (incorporated by reference to Exhibit 10.53 to the Annual Report on Form 10-K for the year ended December 31, 2008).

10.38** — Form of Amendment to LTIP grant letters (directors) (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the year ended December 31, 2008).

10.39 — Contribution Agreement dated as of April 29, 2010 by and among PAA Natural Gas Storage, L.P., PNGS GP LLC, Plains All American Pipeline, L.P., PAA Natural Gas Storage, LLC, PAA/Vulcan Gas Storage, LLC, Plains Marketing, L.P. and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to PNG's Current Report on Form 8-K filed May 4, 2010).

10.40 — Omnibus Agreement dated May 5, 2010 by and among Plains All American GP LLC, Plains All American Pipeline, L.P., PNGS GP LLC and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 10.1 to PNG's Current Report on Form 8-K filed May 11, 2010).

10.41** — Form of Transaction Grant Agreement (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2010).

10.42** — Form of 2010 LTIP Grant Letters (incorporated by reference to Exhibit 10.58 to the Annual Report on Form 10-K for the year ended December 31, 2010).

10.43** — Employment Agreement between Plains All American GP LLC and John R. Rutherford dated September 27, 2010 (incorporated by reference to Exhibit 10.59 to the Annual Report on Form 10-K for the year ended December 31, 2010).

10.44 — 364-Day Credit Agreement dated as of December 9, 2011 among Plains All American Pipeline, L.P., as borrower; DNB Bank ASA, as administrative agent; Bank of America, N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 10-K filed December 15, 2011).

10.45 †** — Director Compensation Summary.

12.1 [†]	—	Computation of Ratio of Earnings to Fixed Charges
21.1 [†]	—	List of Subsidiaries of Plains All American Pipeline, L.P.
23.1 [†]	—	Consent of PricewaterhouseCoopers LLP.
31.1 [†]	—	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2 [†]	—	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1 [†]	—	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350
32.2 [†]	—	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350
101. INS[†]	—	XBRL Instance Document
101.SCH[†]	—	XBRL Taxonomy Extension Schema Document
101.CAL[†]	—	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF[†]	—	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB[†]	—	XBRL Taxonomy Extension Label Linkbase Document
101.PRE[†]	—	XBRL Taxonomy Extension Presentation Linkbase Document

[†] Filed herewith

[*] Certain confidential portions of this exhibit have been omitted pursuant to an Application for Confidential Treatment under Rule 24b-2 under the Exchange Act. This exhibit, with the omitted language, has been filed separately with the SEC.

[**] Management compensatory plan or arrangement

Exhibit 2.1

SHARE PURCHASE AGREEMENT

DECEMBER 1, 2011

AMONG

AMOCO CANADA INTERNATIONAL HOLDINGS B.V.

AS VENDOR

- AND -

PLAINS MIDSTREAM CANADA ULC

AS PURCHASER

[*****] indicates redacted terms for which confidential treatment has been requested from the Securities and Exchange Commission (“SEC”). The redacted information has been filed separately with the SEC.

SHARE PURCHASE AGREEMENT

TABLE OF CONTENTS

ARTICLE 1 DEFINITIONS AND INTERPRETATION **1**
1.1 Definitions 1
1.2 Certain Rules of Interpretation 26
1.3 Knowledge 27
1.4 Entire Agreement 27
1.5 Governing Law 27
1.6 Accounting Principles 27
1.7 Currency Conversion 28
1.8 Disclosure 28
1.9 Parol Evidence 28
1.10 Schedules 29
1.11 Interpretation if Closing Does Not Occur 31
1.12 Conflicts 31

ARTICLE 2 PURCHASE AND SALE **31**
2.1 Actions by Vendor and Purchaser Regarding Purchase 31
2.2 Place of Closing 33
2.3 Tender 33
2.4 Escrow Agreement 33

ARTICLE 3 PURCHASE PRICE **33**
3.1 Purchase Price 33
3.2 Payment of Purchase Price and Interim Cash Flow Amount 33
3.3 Post Closing Adjustment to the Working Capital Amount 34
3.4 Interim Cash Flow Adjustment 36
3.5 Expert Determination 37
3.6 Purchase Price Allocation 39

ARTICLE 4 REPRESENTATIONS AND WARRANTIES OF VENDOR **40**
4.1 Incorporation and Registration 40
4.2 Capitalization and Ownership 40
4.3 Right to Sell Shares 40
4.4 Shares of Purchased Entities 41
4.5 Due Authorization 42
4.6 Enforceability of Obligations 43
4.7 Required Approvals 43
4.8 Material Consents 43
4.9 Financial Statements 43
4.10 Business Carried on in the Ordinary Course; Compliance with Applicable Laws and Environmental Laws 44
4.11 Entity Assets 44
4.12 Operation of Entity Assets 45
4.13 Governmental Authorizations; Compliance Therewith 45
4.14 Material Contracts 45

4.15 Powers of Attorney 46
4.16 Futures Transactions 46
4.17 Certain Material Obligations and Authorizations for Expenditure 46
4.18 Guarantees 46
4.19 Borrowed Money 46
4.20 Minute Books 47
4.21 Environmental Matters 47
4.22 Litigation and Unsatisfied Judgements (other than Tax) 47
4.23 Employee Matters 48
4.24 Intellectual Property 49
4.25 Taxes 49
4.26 Treaty-Protected Property 51
4.27 Commissions and Fees 51
4.28 [*****] 51

ARTICLE 5 REPRESENTATIONS AND WARRANTIES OF PURCHASER 51
5.1 Incorporation 51
5.2 Due Authorization 51
5.3 Enforceability of Obligations 52
5.4 Investment Canada Act 53
5.5 Governmental Authorizations 53
5.6 Commissions and Fees 53
5.7 Purchaser as Principal 53
5.8 Sufficient Funds 53
5.9 Purchaser Guarantor 53

ARTICLE 6 REGARDING MATERIAL CLAIMS, REPRESENTATIONS, WARRANTIES AND COVENANTS 54
6.1 Material Claims 54
6.2 Deductible in respect of Claims 55
6.3 Limitation of Liability 56
6.4 Survival of Vendor’s Representations, Warranties, Covenants and Indemnities and Limitations on Claims 57
6.5 Survival of Purchaser’s Representations, Warranties, Covenants and Indemnities 58
6.6 No Consequential Damages 58
6.7 No Other Representations, Warranties or Covenants of Vendor 58
6.8 No Other Representation, Warranties or Covenants of Purchaser 60
6.9 Restrictions on Claims 60
6.10 Acknowledgement Regarding Scope of Entity Assets 61

ARTICLE 7 PURCHASER’S CONDITIONS 64
7.1 Correctness and Accuracy of Representations and Warranties 64
7.2 Performance of Obligations 64
7.3 Required Approvals Obtained 65
7.4 Material Consents Obtained 65
7.5 No Legal Impediment to Closing 65
7.6 No Injunctions or Restraints 65
7.7 Completion of the Reorganization 65
7.8 IT Related Matters 65

[*****] indicates redacted terms for which confidential treatment has been requested from the SEC. The redacted information has been filed separately with the SEC.

7.9 Vendor’s Closing Deliveries 65
7.10 Payment of Interim Cash Flow Amount 67
7.11 No Damage or Destruction Event 67

ARTICLE 8 VENDOR’S CONDITIONS 67
8.1 Correctness and Accuracy of Representations and Warranties 67
8.2 Performance of Obligations 67
8.3 Required Approvals Obtained 68
8.4 Material Consents Obtained 68
8.5 No Legal Impediment to Closing 68
8.6 No Injunctions or Restraints 68
8.7 Completion of the Reorganization 68
8.8 IT Related Matters 68
8.9 Purchaser’s Closing Deliveries 68

ARTICLE 9 OTHER COVENANTS 69
9.1 Conduct of Business Prior to Closing 69
9.2 Negative Covenants 70
9.3 Credit Support Obligations 72
9.4 Bank Accounts 72

9.5 Access to Material Facilities 73
9.6 Actions to Satisfy Closing Conditions 74
9.7 Preservation of Records 74
9.8 Filings for Required Approvals 74
9.9 HSR Filings 77
9.10 Employee Related Matters 77
9.11 Insurance 77
9.12 Purchase Not Conditional on Financing 78
9.13 Reorganization 78
9.14 Return of Excluded Assets 78
9.15 Delivery of Books and Records 79
9.16 Excluded Owned IP License 80
9.17 IT Related Matters 80
9.18 Confidentiality 80
9.19 Compliance with Privacy Laws 82
9.20 Dispute Resolution 83
9.21 Vendor Standards 84
9.22 Additional Contracts and Litigation Updates 85
9.23 Contracts for NGL Extraction Rights and Gas Supply 85
9.24 Additional Financial Information 86
9.25 Post Closing Cooperation and Access 87
9.26 Leased Rail Cars 87
9.27 Regulatory Matter 87
9.28 Litigation Matter 88
9.29 Covenants in Schedules 88
9.30 Contracts in Non-Purchased Entities 88

ARTICLE 10 INDEMNIFICATION 89
10.1 Mutual Indemnities for Breaches of Representations, Warranties and Covenants; Other Matters 89
10.2 Purchaser Indemnity Relating to Environmental Liabilities and Abandonment and Reclamation Obligations 90
10.3 Purchaser Indemnity Relating to the Business and Other Matters 91
10.4 Vendor Indemnity Relating to Certain Liabilities 91
10.5 Vendor Indemnity Relating to the Non-NGL Business 92
10.6 Procedures Relating to Indemnification Between Vendor and Purchaser 93
10.7 Indemnification Procedures for Third Party Claims (other than Tax Claims) 93
10.8 Holding of Indemnities 95
10.9 Claims Net of Insurance 96
10.10 Mitigation 96
10.11 Adjustment to Purchase Price 96
10.12 Subrogation 96
10.13 Access and Co-operation in Respect of Vendor Indemnified Matters 97
10.14 Assignment of Benefits under Indemnified Litigation Claims 97
10.15 Litigation Support Agreement 98
10.16 No Waiver of Indemnification Rights 98

ARTICLE 11 TAX MATTERS 98
11.1 Liabilities for Taxes 98
11.2 Tax Returns 100
11.3 Remittance of Tax 100
11.4 Tax Refunds 101
11.5 Confidentiality of Tax Information 101
11.6 No Section 338 Election 102
11.7 Tax Claims 102
11.8 Assistance and Cooperation 103
11.9 Coordination with Other Provisions 104
11.10 Tax Changes Post-Closing 105
11.11 Certain Closing Day Transactions 105

ARTICLE 12 TERMINATION AND CLOSING 105
12.1 Termination 105
12.2 Walk Right Threshold 106
12.3 Notice of Termination 107
12.4 [*****] 107
12.5 Deposit 109
12.6 Remedies Exclusive; Specific Performance 109
12.7 Exception to Confidentiality Agreement 109
12.8 Confidential Information 109

[*****] indicates redacted terms for which confidential treatment has been requested from the SEC. The redacted information has been filed separately with the SEC.

ARTICLE 13 GENERAL 110
13.1 Waiver 110
13.2 Public Notices 110
13.3 Assignment 111
13.4 Notices 112
13.5 Further Assurances 113
13.6 No Recourse 113
13.7 Time of the Essence 114
13.8 Amendment 114
13.9 Invalidity 114
13.10 Counterparts 114
13.11 Enforcement 114
13.12 No Third-Party Beneficiaries 114
13.13 Expenses 114
13.14 Removal of Name 115

SHARE PURCHASE AGREEMENT

THIS AGREEMENT is made as of December 1, 2011 between:

Amoco Canada International Holdings B.V.
a corporation incorporated under the laws of the Netherlands
(the "**Vendor**")

- and -

Plains Midstream Canada ULC
a corporation incorporated under the laws of Alberta
(the "**Purchaser**")

RECITALS:

A. Vendor has agreed to sell to Purchaser, and Purchaser has agreed to purchase from Vendor, the Shares on the terms and conditions of this Agreement.

B. Purchaser Guarantor has agreed to guarantee the obligations of Purchaser on the terms set forth in the Purchaser Parent Guarantee.

C. Vendor Guarantor has agreed to guarantee the obligations of Vendor on the terms set forth in the Vendor Parent Guarantee.

IN CONSIDERATION of the covenants, agreements, representations, warranties and payments herein set forth, the Parties covenant and agree as follows:

ARTICLE 1
DEFINITIONS AND INTERPRETATION

1.1 Definitions

Whenever used in this Agreement, the following words and terms shall have the meanings set forth below:

"**Abandonment and Reclamation Obligations**" means any and all past, present and future Liabilities of any of the Purchased Entities or their predecessors or successors in interest (and any and all Losses associated with or related to such Liabilities), whether under Contracts, Previously Owned Asset Agreements or Applicable Law, in any way, directly or indirectly, caused by, arising from, incurred in connection with or relating to any of the following:

(a) the abandonment of assets, including the closing, decommissioning, dismantling or removal of tangibles, equipment and facilities and the plugging and abandonment of wells, and

(b) the restoration, remediation or reclamation of the Environment, including the surface or subsurface of lands performed or to be performed in connection with or as a part of the activities described in item (a) of this definition.

and any and all Claims associated with or relating to any of the foregoing.

"**Accounting Firm**" means Deloitte and Touche LLP, Chartered Accountants or another nationally recognized accounting firm agreed upon by the Parties.

“**Affiliate**” means, as to a Person, any other Person controlling, controlled by or under common control with that Person where “control”, “controlling” or “controlled” means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of another Person, whether through the ownership of voting securities or by contract, partnership agreement, trust arrangement or other means, either directly or indirectly, that results in control in fact, provided however, that direct or indirect ownership of shares of a corporation carrying more than 50% of the voting rights shall constitute control of that corporation, and further provided that:

(a) the Purchased Entities shall be conclusively deemed to be Affiliates of Vendor as to any matter or thing relating to the period prior to Closing Time, and

(b) the Purchased Entities shall be conclusively deemed to be Affiliates of Purchaser as to any matter or thing relating to the period after the Closing Time.

“**Agreement**” means this Share Purchase Agreement, including the recitals and all Schedules and Exhibits hereto, and includes all written instruments supplementing, amending or confirming this Agreement agreed to by the Parties after the date hereof.

“**Alaska Gas Records**” means all documents, information, books and records (including electronic copies thereof) of BP Exploration (Alaska) Inc. (“**BPXA**”), the Corporation or their Affiliates relating to the Alaska gas pipeline projects sponsored by Denali — The Alaska Gas Pipeline LLC (“**Denali**”) or TransCanada Alaska Company, LLC (“**TransCanada**”), including records provided to BPXA, the Corporation or their Affiliates by Denali or TransCanada.

“**Applicable Laws**” means all Laws (including Privacy Laws), other than Environmental Laws, but including any Laws to the extent that they relate to Abandonment and Reclamation Obligations.

“**Base Price**” has the meaning given to that term in Section 3.1.

“**Books and Records**” means original or copies, including electronic copies, of books and records, including financial and accounting records, corporate records, inventory and other asset records, sales and purchase records, customer files, production and other operational data, equipment maintenance data, cost and pricing information, supplier lists, customer lists, business reports, plans and projections, title documents, surveys, files and correspondence that:

(a) are in the possession or under the control of Vendor or its Affiliates,

(b) reflect material transactions that have occurred within a period of five (5) years prior to the date hereof,

(c) relate exclusively to the Business as conducted by the Purchased Entities, and

(d) are necessary for the conduct of the Business after Closing by the Purchased Entities,

but specifically excluding the following (collectively, the “**Excluded Books and Records**”):

(i) any Divestiture Information and any other information pertaining to the sale process leading to the Purchase,

(ii) any information, documents, books and records that relate to or are included in Excluded Assets,

(iii) the Alaska Gas Records,

(iv) financial or other data and information that cannot, with reasonable commercial efforts, be identified by Vendor or be segregated by Vendor or its Affiliates (including the Purchased Entities) from the data, information and records systems of Vendor and its Affiliates,

(v) any such books and records insofar as they relate to pension plans or matters pertaining to pensions for the benefit of any employee or former employee of Vendor or any of its Affiliates (including the Purchased Entities),

(vi) any such books and records insofar as they relate to employees of Vendor or any of its Affiliates other than Entity Employees, and any such books and records insofar as they relate to historical pay, performance, attendance, disciplinary or medical information of Transferred Employees, including personnel files, under Schedule 9.10 Part B except where such information is expressly necessary to deliver new employment terms commensurate with the terms of Schedule 9.10 Part B,

(vii) any such books and records insofar as they are Tax Records of Vendor or of any of its Affiliates or any of the Purchased Entities,

(viii) any such books and records that pertain to risk management matters, except for books and records relating to Futures Transactions that will be outstanding at the Closing Time, and

(ix) any books and records other than those books and records described in (a) through (d) above.

Nothing in this definition shall limit Purchaser’s right to receive the records described in Sections 9.15(a) to (e).

“**Business**” means the business presently and heretofore carried on by the Purchased Entities and their predecessors in interest relating to the purchase, extraction, gathering, fractionation, storage, transportation and wholesale marketing of NGLs.

“**Business Day**” means a day, other than a Saturday or Sunday, on which the principal commercial banks located in Calgary, Alberta, Houston, Texas, Luxembourg, the Netherlands and London, England are open for business during normal banking hours.

“**Canada Transportation Act**” means the *Canada Transportation Act* (Canada).

“**Canada Transportation Act Approval**” means:

(a) Purchaser shall have received a notice from the Minister of Transport pursuant to subsection 53.1(4) of the Canada Transportation Act that the Minister of Transport is of the opinion that the transactions contemplated by this Agreement do not raise issues with respect to the public interest as it relates to national transportation, or

(b) the transactions contemplated by this Agreement shall have been approved by the Governor in Council in accordance with subsection 53.2(7) of the Canada Transportation Act,

and, in either such case, the completion of the transactions contemplated by this Agreement is not prohibited under subsection 53.2(1) of the Canada Transportation Act.

“**Canadian Dollars**” means lawful money of Canada.

“**Canadian Purchased Entities**” has the meaning given to that term in Section 4.25;

“**Claim**” means any action, claim, demand, lawsuit, audit proceeding or arbitration, or any proceeding or investigation by a Governmental Authority including, except where otherwise expressly excluded, a Tax Claim.

“**Closing**” means the closing of the Purchase as contemplated by this Agreement.

“**Closing Consideration**” has the meaning given to that term in Section 3.2(a)(ii).

“**Closing Date**” means, without derogating from the fact that Closing is subject to the satisfaction or waiver, at or before the Closing Time, of each of the conditions set out in Article 7 and Article 8:

(a) if the date on which the Regulatory Condition is satisfied is on or before the seventh (7th) day of a calendar month, then the 1st day of the calendar month following the month in which the Regulatory Condition is satisfied (whether or not a Business Day), or

(b) if the date on which the Regulatory Condition is satisfied is after the seventh (7th) day of a calendar month, then the 1st day of the second calendar month following the month in which the Regulatory Condition is satisfied (whether or not a Business Day) , or

(c) such other date as the Parties may agree upon in writing as the date on which the Closing shall take place;

provided, however, that if the IT Condition has not been satisfied by the Closing Date as defined in (a), (b) or (c) above, either Party shall have the right, on written notice to the other Party

given at least ten (10) Business Days prior to such Closing Date, to extend the Closing Date to the 1st day of the calendar month next following such Closing Date (whether or not a Business Day), and, in like manner, if the IT Condition has not been satisfied by the extended Closing Date, either Party shall have the right, on written notice to the other Party given at least ten (10) Business Days prior to the extended Closing Date, to extend the Closing Date to the 1st day of the calendar month next following the extended Closing Date (whether or not a Business Day).

For the avoidance of doubt, the Closing Date may not be extended by more than two months due to the inability of either Party to satisfy the IT Condition.

“**Closing Document**” means a document or certificate delivered at the Closing Time pursuant to this Agreement.

“**Closing Interim Cash Flow Amount**” has the meaning given to that term in Section 3.4(a).

“**Closing Time**” means 9:00 a.m. (Calgary time)/5:00 p.m. (Central European time) on the Closing Date, or such other time on such date as the Parties may agree upon in writing.

[*****]

“**Code**” means the United States Internal Revenue Code of 1986, as amended.

“**Commissioner**” means the Commissioner of Competition appointed pursuant to the Competition Act or any person authorized to act on behalf of the Commissioner.

“**Competition Act**” means the *Competition Act* (Canada).

“**Competition Act Approval**” means, in respect of the Purchase, that:

(a) an advance ruling certificate pursuant to section 102 of the Competition Act shall have been issued by the Commissioner, or

(b) a "no action letter" in form and substance satisfactory to Purchaser acting reasonably shall have been received from the Commissioner indicating that she does not, at that time, intend to make an application under section 92 of the Competition Act and either:

(i) any applicable waiting period under section 123 of the Competition Act has expired or been terminated, or

(ii) a waiver under section 113(c) of the Competition Act of the obligation to notify the Commissioner and supply information shall have been granted by the Commissioner.

"**Conditions**" means either or both of Vendor's Conditions and Purchaser's Conditions, as applicable.

"**Confidential Contracts**" means those Contracts described or referred to in Schedule 1.1A.

[*****] indicates redacted terms for which confidential treatment has been requested from the SEC. The redacted information has been filed separately with the SEC.

"**Confidential Information**" means, as to any Person, all Trade Secrets and all proprietary and confidential manufacturing, financial, marketing, operational, organizational, know-how, personnel, customer or vendor, technical and other information or data relating to the business of such Person, including, without limitation, all correspondence, memoranda, notes, summaries, analyses, compilations, forecasts, studies, models, extracts of and documents and records reflecting, based upon or derived from such information or data, regardless of who prepares it, as well as all copies and other reproductions thereof, whether in writing or stored or maintained on computer-related or other electronic media.

"**Confidentiality Agreements**" means the Confidentiality Agreement made as of January 28, 2011 between the Corporation and Plains All American Pipeline, L.P. (the "**January 28, 2011 Confidentiality Agreement**"), Consent Agreement Regarding Confidential Information made as of June 15, 2011 between BP Canada Energy Company and AltaGas Extraction and Transmission Limited Partnership; Assignment Agreement And Consent To Disclosure made as of June 21, 2011 among BP Canada Energy Company, Plains All American Pipeline, L.P., and Nova Chemicals Corporation, as amended; Assignment Agreement And Consent To Disclosure made as of June 23, 2011 among BP Canada Energy Company, Plains All American Pipeline, L.P., and Provident Energy Ltd., as amended; Assignment Agreement And Consent To Disclosure made as of June 27, 2011 among BP Canada Energy Company, Plains All American Pipeline, L.P., and Shell Canada Energy, as amended; Assignment Agreement And Consent To Disclosure made as of July 7, 2011 among BP Canada Energy Company, Plains All American Pipeline, L.P., and Imperial Oil, as amended; Assignment Agreement And Consent To Disclosure made as of July 15, 2011 among BP Canada Energy Company, Plains All American Pipeline, L.P., and Dow Chemical Canada ULC, as amended; Assignment Agreement And Consent To Disclosure made as of July 31, 2011 among BP Canada Energy Company, Plains All American Pipeline, L.P., and Inter Pipeline Fund, as amended; and Assignment Agreement and Consent to Disclosure entered into effective November 22, 2011 between BP Canada Energy Company, BP Canada Energy Resources Company, Dome NGL Pipeline Ltd., Kinder Morgan Canada Company, Kinder Morgan Cochin ULC, and Plains All American Pipeline, L.P.

"**Constating Document**" means, in respect of a Person, the articles of incorporation, amalgamation or continuance, bylaws, memorandum of association, partnership agreement or similar constituting document of a Person, as the case may be.

"**Contracts**" means, with respect to any Person, any contracts, leases, licences and contractually binding arrangements, agreements and commitments of that Person, and includes (i) all quotations, orders or tenders for contracts which remain open for acceptance, and (ii) all manufacturers' or suppliers' warranties, guarantees or commitments (express or implied).

"**Corporation**" means BP Canada Energy Company or its successor by amalgamation pursuant to the Reorganization.

"**Covenant Notice Period**" has the meaning given to that term in Section 6.4(b).

"**Credit Support**" has the meaning given to that term in Section 9.3(a).

"**Credit Support Counterparty**" has the meaning given to that term in Section 9.3(a).

"**Damage or Destruction Event**" means damage, destruction, condemnation, expropriation or other casualty loss or impairment of use with respect to any of the Entity Assets.

"**Data Room**" means the virtual data room established by or for Vendor through Merrill Datasite and each physical data room established by or for Vendor, in each such case, containing information, materials and records pertaining to the Business and the Purchased Entities to which Purchaser was granted access.

"**Dedicated ERP Environment**" has the meaning given to that term in Schedule 9.17 hereof.

"**Deposit**" has the meaning given to that term in Section 3.2(a)(i).

"**Disclosed Personal Information**" has the meaning given to that term in Section 9.19(a).

"**Discretionary Inventory**" means "Discretionary Inventory" as described in Schedule 1.1I.

"**Divestiture Information**" means all information, documents, books and records in respect of, relating to or in connection with:

(a) the valuation of any of the Purchased Entities, the shares of any of the Purchased Entities, including the Shares, any of the Entity Assets or the Business or any part thereof,

(b) any advice from Vendor's Counsel, Vendor's Investment Bankers and any other Related Party of Vendor, including the Purchased Entities, with respect to the divestiture of any of the Purchased Entities, the shares of any of the Purchased Entities, including the Shares, any of the Entity Assets or the Business or any part thereof, or

(c) the process and proceedings with respect to any such divestiture,

but excluding any confidentiality agreements entered into by Vendor, or any of the Purchased Entities or any of their respective Affiliates in connection with the proposed sale of the Business.

"**Effective Date**" means October 1, 2011.

"**Effective Time**" means 11:59 p.m. (Calgary time) on September 30, 2011.

"Employee Benefit Arrangements" means all benefit, incentive and compensation schemes, arrangements and policies for the benefit generally of Entity Employees, including share and cash-based incentive and compensation arrangements, and benefits relating to sickness, ill-health, injury, disability, lifestyle, time-off, employee loans, retirement (including pension benefits and retirement benefit plans), death, leaving service or termination of employment.

"**Employment Agreements**" means all employment, severance, change of control, retention, bonus or similar agreements with Entity Employees, whether written or unwritten, including work place rules and policies applicable to and for the benefit of Entity Employees.

"**Employee Obligations**" means obligations to Entity Employees under Employment Agreements and Employee Benefit Arrangements.

"**Encumbrance**" means any lien, mortgage, charge, pledge, hypothecation, security interest or other encumbrance or adverse claim of any kind or character whatsoever.

"**Entity Assets**" means all of the tangible and intangible property (whether real, personal, absolute or contingent, legal or beneficial or mixed), rights, benefits, privileges and other property or assets owned, held or leased by the Purchased Entities at the Closing Time to the extent used by them in connection with the ownership or operation of the Business, including, in any event, all the interests of the Purchased Entities in the Material Facilities, the Leased Entity Assets, the Material Contracts, the Entity IP, the Title and Operating Documents and the Books and Records. For greater certainty, "**Entity Assets**" shall not include any Excluded Assets.

"**Entity Employees**" means the "Employees" as defined in Schedule 9.10 Part A and whose employment transfers with the Business as contemplated by Part A of Schedule 9.10 Part A and the "Transferred Employees" as defined in Schedule 9.10 Part B.

"**Entity IP**" has the meaning given to that term in Section 4.24(a).

"**Environment**" means the components of the earth and includes:

(a) air, land and water,

(b) all layers of the atmosphere,

(c) all organic and inorganic matter and living organisms, and

(d) the interacting natural systems that include components referred to in (a), (b) and (c) above,

and "**Environmental**" means of or in relation to the Environment.

"**Environmental Approvals**" means all Governmental Authorizations issued or required pursuant to Environmental Laws.

"**Environmental Laws**" means all Laws relating in whole or in part to the Environment or the protection thereof, and/or the storage, generation, use, handling, manufacture, processing, transportation, treatment, Release, disposal, reclamation or remediation of Hazardous Substances, but excluding any such Laws to the extent that they relate to Abandonment and Reclamation Obligations.

"**Environmental Liabilities**" means any and all past, present and future Liabilities of any of the Purchased Entities or any of their predecessors or successors in interest (and any and all Losses associated with or relating to such Liabilities) in any way, directly or indirectly, caused by, arising from, incurred in connection with or relating to any of the following:

(a) the manufacture, construction, processing, distribution, use, holding, collection, accumulation, generation, treatment, stabilization, storage, disposal, handling or transportation of Hazardous Substances,

(b) compliance with present and future Environmental Laws and Environmental Approvals,

(c) Releases of Hazardous Substances or other substances, and

(d) the removal, assessment, monitoring, sampling, response, abatement, clean-up, investigation and reporting of contamination or pollution of or other adverse effects on the Environment,

including Liability to third parties for Losses suffered by them in respect thereof, and any and all Claims associated with or relating to any of the foregoing, but excluding Abandonment and Reclamation Obligations (and any and all Claims, Liabilities and Losses associated with or relating to Abandonment and Reclamation Obligations).

"**Environmental Matters**" means any activity, event or circumstance in respect of or relating to Hazardous Substances, including the storage, use, holding, collection, accumulation, assessment, generation, manufacture, processing, treatment, stabilization, disposition, handling, transportation or Release thereof on, at or into the Environment, but excluding any such activity, event or circumstance in respect of or relating to Abandonment and Reclamation Obligations.

"**Environmental Order**" means any order, complaint or notice issued, filed, imposed or consented to by a Governmental Authority relating to actual or alleged non-compliance with Environmental Law.

"**Escrow Agent**" means any Person defined as such under an Escrow Agreement.

"**Escrow Agreement**" means any one or more escrow agreements providing for the holding of the Closing Consideration and the Share Documents pending Closing in accordance with Section 2.1(b) in such form as may be agreed by the Parties.

"**Exchange Rate**" means, with respect to the conversion, translation or exchange of Canadian Dollars into U.S. Dollars or U.S. Dollars into Canadian Dollars, as the case may be, on or for a particular day, the noon spot rate for the applicable currency exchange published by the Bank of Canada on or for such day, or if such day is not a Business Day, on or for the immediately preceding Business Day.

"**Excluded Assets**" means all of the tangible and intangible property (whether real, personal, absolute or contingent, legal or beneficial or mixed), rights, benefits, privileges and other property or assets owned or held by the Purchased Entities or their predecessors to the extent not used by them in connection with the ownership or operation of the Business, including, in any event all property and assets (a) relating to or used in connection with the petroleum and natural gas exploration and production business conducted by Vendor, the Purchased Entities or any of their respective Affiliates or predecessors; or (b) described, referred to or listed in Schedule 1.1B.

"**Excluded Books and Records**" has the meaning given to that term in the definition of "Books and Records".

"**Excluded IP**" means any and all Intellectual Property used by one or more of the Purchased Entities at Closing that is (a) owned by Vendor or any of its Affiliates (other than a Purchased Entity)(the "**Excluded Owned IP**"), including that Excluded Owned IP identified or listed in

Exhibit "A" to Schedule 1.1B, or (b) used by a Purchased Entity pursuant to a license agreement between Vendor or any of its Affiliates (other than a Purchased Entity) and a Person other than Vendor or any of its Affiliates (the "**Excluded Licensed IP**"), including that Excluded Licensed IP identified or listed in Exhibit "B" to Schedule 1.1B; provided that Vendor shall be entitled to revise Schedule 1.1B from time to time prior to Closing to reflect changes in Excluded IP made in the ordinary course of business by Vendor and its Affiliates and, upon delivery of a revised Schedule 1.1B to Purchaser, the revised Schedule 1.1B shall supersede and replace the Schedule 1.1B so revised, and provided further that such changes in Excluded IP shall not result in material reductions or alterations in the functionality of the Dedicated ERP Environment.

"**Existing Credit Support Obligations**" has the meaning given to that term in Section 9.3(a).

"Expert Determination" has the meaning given to that term in Subsection 3.5(a)(i).

"**Final Interim Cash Flow Amount**" has the meaning given to that term in Section 3.4(d).

"**Financial Encumbrance**" means any Encumbrance securing the payment of an amount of money due and owing as at the Closing Time and any Encumbrance securing an obligation to repay borrowed money.

"**Financial Statements**" means the financial statements relating to the Business attached hereto as Schedule 1.1C.

"**Futures Transaction**" means any derivatives transaction (including an agreement with respect thereto) entered into by the Purchased Entities in relation to the Business for the purposes of mitigating commodity, interest or currency risk, which is commonly referred to as a hedge transaction, rate swap transaction, basis swap, forward rate transaction, commodity swap, commodity option, equity or equity index swap, equity or equity index option, bond option, interest rate option, foreign exchange transaction, cap transaction, floor transaction, collar transaction, currency swap transaction, cross-currency rate swap transaction, currency option or any other similar transaction (including any option with respect to any of these transaction) or any combination of these transactions, provided however, for greater clarity, and without limiting the generality of the foregoing, an agreement for the future delivery of a commodity intended to be settled by the delivery of such commodity in the future is not a "Futures Transaction" for the purposes hereof.

"**Governmental Authority**" means any government, regulatory or administrative authority, government department, bureau, agency, commission, board or tribunal or court having jurisdiction on behalf of any nation, province or state or subdivision thereof or any municipality, district or subdivision thereof.

"**Governmental Authorizations**" means all permits, licenses, exemptions, orders, variances, approvals, consents and other authorizations issued by a Governmental Authority under Applicable Law or Environmental Law.

"**Guarantee**", or any derivative thereof, means any guarantee granted by a Purchased Entity to another Person, other than another Purchased Entity, pursuant to which the Purchased Entity guarantees the payment or performance of any indebtedness or other obligation of any other Person, other than another Purchased Entity, and excludes, in any event, (i) indemnities granted

in the Ordinary Course of Business by a Purchased Entity to another Person in a Contract in which such indemnity is incidental to the primary purpose of the Contract, and (ii) Material Contracts listed in Schedule 4.14(a).

"**Hazardous Substance**" means any substance or material that is prohibited, controlled or regulated by any Governmental Authority pursuant to Environmental Laws including pollutants, irritants, contaminants, dangerous goods and substances, toxic or hazardous substances and materials, petroleum and its derivatives and by-products (including NGLs) and other hydrocarbons, all as defined in or pursuant to any Environmental Laws.

"**HSR Act**" means the Hart Scott Rodino Antitrust Improvement Act.

"**IFRS**" means International Financial Reporting Standards.

"**Indemnification Notice**" has the meaning given to that term in Section 10.6.

"**Indemnified Litigation Claims**" means the Vendor Indemnified Litigation Claims and the litigation Claims for which Vendor has indemnified Purchaser pursuant to Section 10.4(c).

"**Indemnified Party**" has the meaning given to that term in Section 10.1(a).

"**Indemnifying Party**" has the meaning given to that term in Section 10.1(a).

"**Information Memorandum**" means the Confidential Information Memorandum dated January 2011 relating to the potential sale of the Business.

"**Intellectual Property**" means all intellectual property rights, arising from or in respect of the following, whether protected, created or arising under Applicable Laws of Canada or the United States or any other jurisdiction or under any international convention: (a) patents and patent applications, including all continuations, divisionals, continuations-in-part, and provisionals, and patents issuing on any of the foregoing, and all reissues, reexaminations, substitutions, renewals and extensions of any of the foregoing (collectively, "**Patents**"), (b) trademarks, service marks, trade names, trade dress, logos, corporate names and other source or business identifiers, together with the goodwill associated with any of the foregoing, and all applications, registrations, renewals and extensions of any of the foregoing, (c) Internet domain names, (d) copyrights, works of authorship and moral rights, and all registrations, applications, renewals, extensions and reversions of any of the foregoing, and (e) confidential and proprietary information, trade secrets and non-public discoveries, concepts, ideas, research and development, technology, know-how, formulae, inventions, compositions, processes, techniques, technical data and information, procedures, designs, drawings, specifications, databases, and other information, including customer lists, supplier lists, pricing and cost information, and business and marketing plans and proposals, in each case, excluding any rights in respect of any of the foregoing that comprise or are protected by Patents (collectively, "**Trade Secrets**").

"**Interest Rate**" means two per cent (2%) per annum.

"**Interim Cash Flow Amount**" means the amount defined in and calculated in accordance with Schedule 1.1M.

"**Interim Financial Statements**" means the interim unaudited financial statements of the Business for the nine month period ended September 30, 2011 included in the Financial Statements.

"**Interim Period**" means the period from and including the Effective Date until and including the day immediately before the Closing Date.

"**Interim Period Cash Flow Statement**" has the meaning given to that term in Section 3.4.

"**Interim Period Financial Statements**" means the unaudited financial statements relating to the Business for the Interim Period.

"**Investment Canada Act**" means the *Investment Canada Act* (Canada).

"**Investment Canada Act Approval**" means the responsible Minister designated pursuant to the Investment Canada Act has sent a notice to Purchaser that he is satisfied that the Purchase is likely to be of net benefit to Canada or is deemed to be so satisfied pursuant to Part IV of the Investment Canada Act.

"**IST Contracts**" means (i) contracts for the purchase, sale or exchange of natural gas, electricity or any transportation or transmission capacity or storage in respect of natural gas or electricity and any swaps, options or other derivatives in respect thereof, (ii) master netting agreements, credit support addenda and other margining agreements in connection with the contracts referred to in (i) above, (iii) brokerage agreements, (iv) agency agreements, (v) asset management agreements, (vi) consultancy agreements, (vii) exchange participation agreements, (viii) electronic subscription agreements, (ix) confidentiality agreements, and (x) any other agreements and arrangements entered into in connection with the natural gas or electricity trading and marketing business currently carried on by the Purchased Entities, in any of the foregoing cases, to which any of the Purchased Entities is a party.

"**IT Condition**" has the meaning given to that term in Section 7.8.

"**KPMG Report**" means, collectively, the report prepared by KPMG dated February 28, 2011 in connection with the sale of the Business entitled "Canadian Natural Gas Liquids Business Due diligence assistance" and the report prepared by KPMG dated March 28, 2011 in connection with the sale of the Business entitled "Canadian Natural Gas Liquids Business Addendum to the due diligence report dated February 28, 2011".

“**Laws**” means all laws, statutes, rules, regulations, official directives and orders of Governmental Authorities (whether administrative, regulatory, legislative, executive or otherwise) including judgments, orders and decrees of courts, commissions or bodies exercising similar functions.

“**Leased Entity Assets**” means all of the tangible and intangible property used and leased by the Purchased Entities in connection with the ownership or operation of the Business including rail cars to the extent transferred to the Purchased Entities pursuant to Schedule 1.1L, all leased real property on or in which the Material Facilities and storage caverns are located and all real property described in Schedule 4.11. For greater certainty, Leased Entity Assets shall not include Excluded Licensed IP.

“**Liabilities**” means liabilities and obligations, whether under common law, in equity, under Applicable Law, Environmental Law or otherwise, whether tortious, contractual, vicarious, statutory or otherwise, whether absolute or contingent, and whether based on fault, strict liability or otherwise.

“**Litigation Support Agreement**” means an agreement substantially in the form attached as Exhibit C.

“**Losses**” means, in respect of a Person and in relation to a matter (including a Liability), any and all losses, damages, costs, expenses, charges (including all penalties, assessments and fines) which that Person suffers, sustains, pays or incurs in connection with that matter and includes reasonable costs of legal counsel (on a solicitor and its own client basis), other professional advisors and consultants incurred in connection therewith and reasonable costs of investigating and defending Claims associated with or relating to that matter, regardless of whether those Claims are sustained.

“**Material Adverse Effect**” means any adverse effect or adverse change (other than as a result of or in respect of matters or changes contemplated or permitted by this Agreement) that, in either such case, results or could reasonably be expected to result in aggregate Losses to the Purchaser and the Purchased Entities in excess of U.S.$150,000,000, but does not include any adverse effect or adverse change caused by or resulting from (i) the Permitted Pre-Closing Actions, (ii) the resignation of any of the Entity Employees, (iii) the fact that the Business is presently supported by Vendor and Vendor’s Affiliates (other than the Purchased Entities) and the withdrawal of that support after Closing, (iv) the termination of any Contracts (other than by Vendor, a Purchased Entity or any Affiliate thereof) (A) for the sale of NGLs, or (B) for the purchase of NGL extraction rights, or (C) for the supply of natural gas and NGLs at field gas processing facilities and straddle plants, in each such case, as a result of the transactions contemplated hereby, (v) general economic conditions or changes therein, (vi) fiscal or monetary policies of Governmental Authorities or changes therein, (vii) changes to the cost or price of services or commodities, (viii) changes in the oil and gas business or the NGLs business generally (including any change or effect resulting from any regulatory action or intervention of general application or from changes to Applicable Law or Environmental Law), (ix) changes in interest rates, currency exchange rates and stock markets generally, (x) changes in Law, or (xi) the announcement or pendency of the transactions contemplated herein.

“**Material Claim**” has the meaning given to that term in Section 6.1.

“**Material Consent**” means any approval or consent required to be described, referred to or listed in Schedule 4.8.

“**Material Contract**” means any Contract that is binding upon any of the Purchased Entities:

(a) under which any of the obligations of any of the parties thereto remains outstanding,

(b) that relates to the conduct of the Business or the operation of the Entity Assets, and

(c) which either:

(i) is an ownership or operating agreement relating to a Material Facility or the Empress II Straddle Plant,

(ii) is an agreement with a remaining term of two (2) years or more for the fractionation, processing or transportation of 5,000 barrels per day or more of NGLs,

(iii) is an agreement with a remaining term of two (2) years or more for the storage of 100,000 barrels or more of NGLs,

(iv) is an agreement for the sale of approximately 10,000,000 U.S. gallons or more of NGLs in either the 2011/2012 contract year or the 2012/2013 contract year,

(v) is an agreement for the purchase of approximately 300,000 barrels or more of NGLs in either the 2011/2012 contract year or the 2012/2013 contract year,

(vi) is an agreement for the purchase or sale of any commodity between Vendor or any Affiliate of Vendor other than a Purchased Entity, on the one hand, and a Purchased Entity, on the other, or

(vii) is an agreement, understanding or arrangement for the purchase of NGL extraction rights, make up gas and fuel gas from, or the sale of residue gas to, the Purchased Entities’ affiliated Integrated Supply and Trading division,

where “2011/2012 contract year” refers to the 12 month period commencing in 2011 and ending in 2012 to which the sale or purchase obligations under the applicable Contract relate and “2012/2013 contract year” refers to the 12 month period commencing in 2012 and ending in 2013 to which the sale or purchase obligations under the applicable Contract relate. For greater certainty Material Contracts shall not include Contracts governing the use of Excluded Licensed IP.

"**Material Facilities**" means the facilities described as "Material Facilities" in Schedule 1.1D and a "**Material Facility**" means any one of the Material Facilities.

"**NGL Inventory**" means "Discretionary Inventory", "Exchange Inventory" and "Neutral Inventory", as described in Schedule 1.1I.

"**NGLs**" means ethane, propane, normal butane, iso-butane, pentanes and heavier hydrocarbons, frac oil, solvent and synthetic crude oil used for batch segregation purposes, or any combination thereof, and other substances found in small quantities in the foregoing substances.

"**Non-NGL Business**" means any business, other than the Business, presently or heretofore carried on by the Purchased Entities and their predecessors in interest, including, any business or activities associated with the Excluded Assets.

"**Notice**" has the meaning given to that term in Section 13.4.

"**Notice Period**" has the meaning given to that term in Section 6.5.

"**Ordinary Course of Business**":

(a) means conduct that is consistent with prudent NGLs industry practice and the current practices of the applicable Purchased Entities and is or are taken in the ordinary course of normal day-to-day operations of the Purchased Entities, and

(b) shall be deemed, in any event, to include:

(i) all reasonably necessary actions taken by any of the Purchased Entities in connection with, in contemplation of or in preparation for the Purchase, the Closing, any Permitted Pre-Closing Action or any other action or transaction contemplated or permitted by this Agreement,

(ii) in respect of any Contract pertaining to the Business, the termination, renegotiation, renewal or amendment thereof in accordance with the usual business practices of the Purchased Entities with respect thereto, and

(iii) the settlement of any Claims and litigation for and in respect of which Vendor has the obligation to indemnify Purchaser hereunder.

"**Outside Date**" means the earlier of (i) if the Regulatory Condition is satisfied on or before the Regulatory Condition Deadline, the Business Date next following the last date to which the Closing Date may be extended in accordance with the definition of "Closing Date", and (ii) if the Regulatory Condition is not satisfied on or before the Regulatory Condition Deadline, the Business Day next following the Regulatory Condition Deadline.

"**Parties**" means, collectively, Vendor and Purchaser, and, individually, either of them.

"**Permitted Contest**" means action taken by any of the Purchased Entities in good faith by appropriate proceedings diligently pursued to contest any Taxes, Claim or Encumbrance, provided that proceeding with that action would not reasonably be expected to risk the occurrence of a Material Adverse Effect.

"**Permitted Encumbrance**" means, in respect of Vendor, any of the Purchased Entities and any of the Entity Assets, as the case may be:

(a) undetermined or inchoate liens and incidental to construction by or current operations of such Person (including liens of carriers, warehousemen, mechanics, materialmen, builders, operators, processors and landlords) which have not been filed pursuant to Applicable Laws or Environmental Laws against such Person or in respect of which no steps or proceedings to enforce such lien have been initiated or which relate to obligations which are not due or delinquent, or if due or delinquent, are being contested by a Permitted Contest,

(b) easements, rights-of-way, covenants, servitudes, licenses, zoning or other similar rights or restrictions in respect of property owned, leased or otherwise held by, or subject to any rights of, that Person, whether or not recorded (including rights-of-way and servitudes for railways, sewers, drains, pipelines, gas and water mains, electric light and power and telephone or telegraph or cable television conduits, poles, wires and cables)

which, either alone or in the aggregate, do not materially detract from the value of such property or materially impair its use in the operation of the business of that Person,

(c) any lien or trust arising in connection with workers' compensation, unemployment insurance, pension or employment laws or regulations,

(d) the right reserved to or vested in any Governmental Authority by the terms of any lease, easement, license, franchise, grant or permit held by such Person or by any statutory provision to terminate any such lease, easement, license, franchise, grant or permit or to require annual or other periodic payments as a condition of the continuance thereof,

(e) liens for Taxes, assessments or other charges or levies by Governmental Authorities which are not at the time delinquent or, if delinquent, are being contested by a Permitted Contest,

(f) rights of general application reserved to or vested in any Governmental Authority to levy Taxes on any of the Entity Assets or the income therefrom, or to limit, control or regulate any of the Entity Assets or operations in respect of the Entity Assets in any manner,

(g) all reservations, limitations, provisos and conditions in the original grants or transfers from the Crown or any unit of federal, provincial, state or local government of any lands and premises or any interests therein and all statutory exceptions, qualifications and reservations in respect of title, including those provided for in any applicable statute governing title to real property,

(h) public and statutory liens not yet due arising by operation of law,

(i) the terms and conditions of, and Encumbrances arising under, the Title and Operating Documents, including provisions for penalties, suspensions and forfeitures arising under or pursuant to any of the Title and Operating Documents,

(j) rights of first refusal, rights of first offer and/or options, applicable to the Entity Assets which are not triggered by the Purchase,

(k) the rights of third parties to purchase NGLs pursuant to sale contracts entered into in the Ordinary Course of Business,

(l) Encumbrances contained in any agreement for the purchase, sale or transportation of natural gas or NGLs entered into in the Ordinary Course of Business,

(m) any defects or deficiencies in title to the Entity Assets disclosed by Vendor or any of Vendor’s Affiliates to Purchaser on or before the date hereof or that are specifically waived in writing by Purchaser,

(n) Encumbrances:

(i) to secure obligations on surety or appeal bonds and other obligations of a like nature, or

(ii) to secure performance of tenders, statutory obligations, leases and licenses,

provided that each of those liens is entered into in the Ordinary Course of Business and only secures sums not overdue or sums being contested by a Permitted Contest,

(o) judgment liens, but only for so long as enforcement of such judgment liens is not allowed (whether by appeal, bonding, order of a court, agreement or otherwise),

(p) any Encumbrance which secures Purchase Money Obligations,

(q) security given by Vendor or any of the Purchased Entities to a public utility or any Governmental Authority when required by such utility or Governmental Authority in connection with the operation of the Business or the Entity Assets, which individually or in the aggregate do not materially detract from the value of the Entity Assets or materially impair the use of the Entity Assets in the operation of the Business,

(r) leases, including equipment leases, entered into the Ordinary Course of Business,

(s) the terms and conditions of, and Encumbrances arising under, any and all Contracts pertaining to the Business, including Material Contracts,

(t) obligations under Applicable Laws, Environmental Laws and Abandonment and Reclamation Obligations,

(u) any cash collateral which secures outstanding letters of credit or bankers’ acceptances under banking facilities,

(v) zoning entitlement and other land use laws, rules or regulations,

(w) Encumbrances with respect to capital leases,

(x) Encumbrances securing obligations of any of the Purchased Entities to any of the other Purchased Entities,

(y) any Encumbrance filed or registered, or in respect of which notation has been made, at any land titles, land registry and/or recorder’s office, or in any public registry in any jurisdiction in which any of the Entity Assets are located, or at any of the personal property registries in Alberta, Saskatchewan, Manitoba, Ontario and Nova Scotia, and any Encumbrance reflected in the real property records of any applicable Governmental Authority in the United States in which any of the Entity Assets are located,

(z) Encumbrances in favour of, held by, or created by, Purchaser or any of Purchaser’s Affiliates,

(aa) Encumbrances described or referred to in Schedule 1.1E or any other Schedule attached hereto,

(bb) any extension, renewal or replacement (or successive extensions, renewals or replacements), as a whole or in part, of any Encumbrance referred to in the preceding subparagraphs, so long as any extension, renewal or replacement of such Encumbrance is limited to all or any part of the same property that secured the Encumbrance extended, renewed or replaced (plus improvements on such property) and the indebtedness or obligation secured thereby is not increased,

(cc) any Encumbrance held by a Person encumbering the Entity Assets, or any part or portion thereof, in respect of which Vendor delivers a valid written release or no interest letter to Purchaser at or prior to Closing,

(dd) Claims relating to title to the Entity Assets described or referred to in Schedule 1.1E, Schedule 1.1H (but only for those claims listed under the heading "Claims Related to NGL Business") or Schedule 4.22(a), and

(ee) the limited ownership interest of Shell Canada Limited or its successor provided for in the Agreement for the Purchase and Sale of Natural Gas Liquids, dated March 8, 1989, as amended, and the Agreement for the Construction, Ownership and Operation of Natural Gas Liquids Facilities, dated April 1, 1990, as amended, each made between Amoco Canada Petroleum Company Ltd. and Shell Canada Limited relating to:

(i) Fort Saskatchewan and Edmonton Storage,

(ii) Superior Storage, and

(iii) Sarnia Storage and Fractionation,

as defined in Schedule 1 to the first agreement described above;

provided, however, notwithstanding the foregoing, Financial Encumbrances shall not be "Permitted Encumbrances".

"**Permitted Pre-Closing Actions**" means any of the following:

(a) the Reorganization and any and all steps and actions contemplated thereby,

(b) the transfer of Excluded Assets by any of the Purchased Entities to any Affiliate of Vendor, including the assignment of the IST Contracts by any of the Purchased Entities to an Affiliate of Vendor,

(c) the transfer of assets related to the Business to any of the Purchased Entities by any Affiliate of Vendor, provided such transfer shall not be materially adverse to the Business,

(d) the settlement of accounts between Purchased Entities, on the one hand, and Vendor and its Affiliates (other than the Purchased Entities) on the other and all steps and transactions related thereto, and

(e) anything done or not done with the written consent of Purchaser.

"**Person**" means any individual, sole proprietorship, partnership, limited partnership, corporation, limited or unlimited liability company, unincorporated association, unincorporated syndicate, unincorporated organization, trust, body corporate, Governmental Authority or other entity, and a natural person in such person's capacity as trustee, executor, administrator or other legal representative.

"**Personal Information**" means identifiable information about an Entity Employee.

"**Previously Owned Asset Agreements**" means any Contracts, whether an ownership or operating agreement, a purchase and sale agreement or any other type of agreement, to which a Purchased Entity or any predecessor thereof is a party and which relates to a Previously Owned Asset. For the avoidance of doubt, "**Previously Owned Asset Agreements"** includes that certain [*****].

"**Previously Owned Assets**" means all of the tangible and intangible property (whether real, personal, absolute or contingent, legal or beneficial or mixed), rights, benefits, privileges and other property or assets previously owned or held by the Purchased Entities or their predecessors in interest and that were used by them in connection with the Business. For the avoidance of doubt, "**Previously Owned Assets**" includes [*****].

"**Privacy Laws**" means any and all Laws relating to privacy and the collection, use and disclosure of Personal Information, including the *Personal Information Protection and Electronic Documents Act* (Canada) and/or any comparable provincial law (including the *Personal Information Protection Act* (Alberta)).

"**Purchase**" means the purchase by Purchaser of the Shares from Vendor as contemplated by this Agreement.

"**Purchase Money Obligations**" means any debt or other obligations of any of the Purchased Entities created or assumed to finance any part of the purchase price of real or tangible personal property, including any extensions, renewals or refunding of any such debt.

"**Purchase Price**" has the meaning given to that term in Section 3.1.

"**Purchase Price Allocation**" has the meaning given to that term in Section 3.6.

"**Purchased Entities**" means the Corporation and each of the other corporations and entities listed in Schedule 1.1F.

"**Purchaser Guarantor**" means Plains All American Pipeline, L.P.

"**Purchaser Indemnified Abandonment and Reclamation Obligations**" means Abandonment and Reclamation Obligations in any way, directly or indirectly, caused by, arising from, incurred in connection with or relating to:

(a) the Business,

[*****] indicates redacted terms for which confidential treatment has been requested from the SEC. The redacted information has been filed separately with the SEC.

(b) the ownership or operation of any of the Entity Assets, including Abandonment and Reclamation Obligations incurred under Previously Owned Asset Agreements that relate to Entity Assets, or

(c) any of the activities carried out in connection with the Business,

provided, however, that "**Purchaser Indemnified Abandonment and Reclamation Obligations**" shall not include any matter for which and to the extent that Vendor is liable to Purchaser under the indemnities contained in Section 10.1(a) for a breach of the representations and warranties set forth in Sections 4.21 only, Section 10.4, or Section 10.5.

"**Purchaser Indemnified Environmental Liabilities**" means Environmental Liabilities in any way, directly or indirectly, caused by, arising from, incurred in connection with or relating to:

(a) the Business,

(b) the ownership or operation of any of the Entity Assets, including Environmental Liabilities incurred under Previously Owned Asset Agreements that relate to Entity Assets, or

(c) any of the activities carried out in connection with the Business,

provided, however, that "**Purchaser Indemnified Environmental Liabilities**" shall not include any matter for which and to the extent that Vendor is liable to Purchaser under the indemnities contained in Section 10.1(a) for a breach of the representations and warranties set forth in Sections 4.21 only, Section 10.4, or Section 10.5.

"**Purchaser Indemnified Parties**" has the meaning given to that term in Section 10.1(a)

"**Purchaser Parent Guarantee**" means the guarantee executed and delivered to Vendor by Purchaser Guarantor concurrently with the execution and delivery of this Agreement.

"**Purchaser's Counsel**" means Bennett Jones LLP.

"**Purchaser's Conditions**" has the meaning given to that term in Article 7.

"**Purchaser's ICF Objection**" has the meaning given to that term in Section 3.4(b).

"**Purchaser's Objection**" has the meaning given to that term in Section 3.3(b).

"**Purchaser's Process Agent**" has the meaning given to that term in Section 9.20.

"**Regulatory Condition**" has the meaning given to that term in Section 7.3.

"**Regulatory Condition Deadline**" means June 30, 2012.

"**Related Party**" means, in reference to a Party or the Purchased Entities, as the case may be:

(a) its Affiliates,

(b) its directors, officers and employees,

(c) its Affiliates' directors, officers and employees,

(d) its Representatives, and

(e) its Affiliates' Representatives.

"**Release**" means any actual, alleged or threatened release, escape, spill, emission, leaking, seepage, pumping, injection, deposit, disposal, discharge, dispersal, leaching or migration of a Hazardous Substance on, into or through the Environment.

"**Reorganization**" means the transactions and other matters described or referred to in Schedule 1.1G and any changes thereto which would not reasonably be expected to materially and adversely affect the value of the Business to Purchaser.

"**Representatives**" means, in reference to a Person, its representatives, agents, legal counsel, consultants and advisors and, in reference to Vendor, includes Vendor's Counsel and Vendor's Investment Bankers.

"**Required Approvals**" means the Competition Act Approval, the Investment Canada Act Approval and the Canada Transportation Act Approval.

"**Senior Officers**" means with respect to:

(a) Vendor, a managing director of Vendor;

(b) the Corporation, the President and the Secretary of the Corporation; and

(c) Purchaser, the President and the Secretary of Purchaser.

"**Share Documents**" has the meaning given to that term in Section 7.9(a).

"**Shares**" means all of the issued and outstanding common shares in the capital of the Corporation at the Closing Time.

"**Tax**" or "**Taxes**" means all taxes, duties, fees, premiums, assessments, imposts, levies and other charges of any kind whatsoever imposed by any Governmental Authority, together with all interest, penalties, fines, additions to tax or other additional amounts imposed in respect thereof (including the failure to withhold, collect or remit any tax), including those levied on, or measured by, or referred to as, income, gross receipts, profits, capital, large corporation, capital gain, alternative minimum, transfer, land transfer, sales, goods and services, harmonized sales, use, value-added, excise, stamp, withholding, business, franchising, property, employer health, payroll, employment, health, social services, education and social security tax, all surtaxes, all customs duties and import and export taxes, and all employment insurance, health insurance and Canada and other Governmental Authority pension plan and workers compensation premiums or contributions, but for greater certainty does not include the Cash Tax Adjustment as defined in Schedule 1.1M.

"**Tax Act**" means the *Income Tax Act* (Canada).

"**Tax Benefit**" has the meaning given to that term in Section 11.1(d).

"**Tax Claim**" has the meaning given to that term in Section 11.7(a).

"**Tax Rate**" has the meaning given to that term in Section 11.1(d).

"**Tax Records**" means any and all Tax Returns and working papers relating to the preparation of Tax Returns, correspondence with Tax authorities in relation to Tax matters and all paper and electronic files and data related thereto.

"**Tax Returns**" includes all returns, reports, declarations, elections, designations, notices, filings, forms, information returns, remittances and similar statements filed or required to be filed with a Governmental Authority or provided or required to be provided to any Governmental Authority in respect of Taxes.

"**Third Party Claim**" means any Claim made against a Party or any of its Related Parties by another Person other than the other Party or any of the other Party's Related Parties.

"**Title and Operating Documents**" means:

(a) certificates of title, deeds, leases, documents granting underground storage rights, rights-of-way, easements, including pipeline easements, licenses, road use agreements, permits and other contracts granting surface interests and other documents of title,

(b) purchase and sale agreements,

(c) agreements for the construction, ownership and operation of facilities,

(d) agreements providing for the gathering, measurement, processing, compression or transportation of NGLs,

(e) operating agreements and procedures,

(f) trust declarations and other agreements, and

(g) agreements for the purchase, sale, fractionation, extraction or storage of natural gas and NGLs or the purchase or sale of crude oil, natural gas and synthetic crude oil,

by virtue of which the Entity Assets are held or which pertain to the ownership, development or operation of the Entity Assets.

"**Trade Secrets**" has the meaning given to that term in the definition of Intellectual Property.

"**Transition Services Agreement**" means an agreement substantially in the form attached as Exhibit D.

"**Treaty-Protected Property**" has the meaning given to that term in subsection 248(1) of the Tax Act.

"**United States Dollars**", "**U.S. Dollars**" and "**U.S. $**" means lawful money of the United States of America.

"**U.S.**" or "**United States**" means the United States of America.

"**U.S. GAAP**" means accounting principles generally accepted in the United States of America.

"**U.S. Purchased Entities**" has the meaning given to that term in Section 9.15.

"**Vendor Fundamental Representations**" has the meaning given to that term in Section 6.4(a).

"**Vendor Guarantor**" means BP Corporation North America Inc.

"**Vendor Indemnified Abandonment and Reclamation Obligations**" means Abandonment and Reclamation Obligations in any way, directly or indirectly, caused by, arising from, incurred in connection with or relating to:

(a) the Non-NGL Business,

(b) the ownership or operation of any of the Excluded Assets or any of the other properties and assets owned or operated by the Purchased Entities or their predecessors used in connection with the Non-NGL Business,

(c) any of the activities carried out by the Purchased Entities or their predecessors in connection with the Non-NGL Business, or

(d) the ownership or operation of any of the Previously Owned Assets,

excluding Abandonment and Reclamation Obligations under the Previously Owned Asset Agreements that relate to the Entity Assets.

"**Vendor Indemnified Environmental Liabilities**" means Environmental Liabilities in any way, directly or indirectly, caused by, arising from, incurred in connection with or relating to:

(a) the Non-NGL Business,

(b) the ownership or operation of any of the Excluded Assets or any of the other properties and assets owned or operated by the Purchased Entities or their predecessors used in connection with the Non-NGL Business,

(c) any of the activities carried out by the Purchased Entities or their predecessors in connection with the Non-NGL-Business, or

(d) the ownership or operation of any of the Previously Owned Assets,

excluding Environmental Liabilities incurred under the Previously Owned Asset Agreements that relate to the Entity Assets.

"**Vendor Indemnified Litigation Claims**" means those Claims described, referred to or listed in Schedule 1.1H.

"**Vendor Indemnified Matters**" means and refers to any Liability, Loss or Claim in respect of which Vendor is obligated to indemnify a Purchaser Indemnified Party hereunder.

"**Vendor Indemnified Parties**" has the meaning given to that term in Section 10.1(a).

"**Vendor Parent Guarantee**" means the guarantee executed and delivered to Purchaser by Vendor Guarantor concurrently with the execution and delivery of this Agreement.

"**Vendor's Conditions**" has the meaning given to that term in Article 8.

"**Vendor's Counsel**" means Fraser Milner Casgrain LLP.

"**Vendor's ICF Review Period**" has the meaning given to that term in Section 3.4(c).

"**Vendor's Insurance**" has the meaning given to that term in Section 9.11.

"**Vendor's Investment Bankers**" means Credit Suisse Securities (Europe) Limited and its Affiliates.

"**Vendor's Process Agent**" has the meaning given to that term in Section 9.20.

"**Vendor's Review Period**" has the meaning given to that term in Section 3.3(c).

"**Warranty Notice Period**" has the meaning given to that term in Section 6.4(a).

"**Working Capital Amount**" means the amount, whether positive or negative, calculated as of the Effective Time for the Purchased Entities to the extent only that such amount (and the components thereof referred to below) relates to the Business or the Entity Assets, equal to the aggregate of:

(a) cash on hand or on deposit with banks or other depositories,

(b) accounts receivable and accrued receivables, including any Tax receivable (other than amounts that are, or relate to, income Taxes) and including any account receivable or accrued receivable from or owed by any of the Affiliates of a Purchased Entity, less the allowance for doubtful accounts,

(c) prepaid expenses including prepaid Taxes, Tax instalments paid to Governmental Authorities, amounts on deposit with Governmental Authorities relating to Tax matters, reassessments or appeals and operating advances, but in all cases excluding amounts that are, or relate to, income Taxes,

(d) Discretionary Inventory and Exchange Inventory, and

(e) other current assets not described above, including any mark-to-market balance sheet amounts of financial derivatives contracts,

minus

(f) U.S. $185,212,000,

(g) accounts payable and accrued current liabilities, including any Tax payable (other than amounts that are, or relate to, income Taxes), including the accrued Exchange Inventory liability and including any account payable or accrued liability to or payable to any of the Affiliates of a Purchased Entity,

(h) accrued Taxes relating to any period ended at or before the Effective Time, whether or not the same have become due, and calculated on the assumption that each of the Purchased Entities had a fiscal year for purposes of the relevant tax legislation ending at the Effective Time, but in all cases excluding amounts that are, or relate to, income Taxes,

(i) other current liabilities not described above, including any mark-to-market balance sheet amounts of financial derivative contracts, but specifically excluding provisions for Abandonment and Reclamation Obligations and Environmental Liabilities included in the Interim Financial Statements,

(j) liabilities identified on the balance sheet in the Interim Financial Statements as “Noncurrent liabilities — Other payables”, and

(k) any other liabilities of the Purchased Entities as of the Effective Time as determined in accordance with IFRS.

For the purposes of this definition:

(i) Discretionary Inventory and Exchange Inventory shall be valued in accordance with Schedule 1.1I.

(ii) inventory, other than NGL Inventory, shall be valued at book value,

(iii) for clarity, Tax receivables and Tax payables will include receivables and payables for or in respect of goods and services and harmonized sales taxes due to or from the Purchased Entities, but not recovered or paid at the Effective Time,

(iv) accounting provisions for deferred income taxes shall not be treated as a current asset or a current liability and will not affect the calculation of the Working Capital Amount,

(v) all amounts shall be calculated on a consolidated basis without duplication for the Purchased Entities in accordance with IFRS,

(vi) any contingent Tax liabilities contemplated by Section 4.25(e) shall not be taken into account in calculating the Working Capital Amount,

(vii) amounts in respect of any item that is otherwise expressed in a currency other than U.S. Dollars shall be translated into U.S. Dollars at the Exchange Rate on September 30, 2011, and

(viii) the Working Capital Amount shall not include the value of NGL Inventory other than Discretionary Inventory, and shall exclude amounts in respect of the Excluded Assets.

1.2 Certain Rules of Interpretation

In this Agreement (including the Schedules):

(a) all references to a time are references to local time in Calgary, Alberta,

(b) except as otherwise expressly provided herein, all references to money amounts are to United States Dollars,

(c) references to an Article, Section or Schedule mean and refer to the specified Article, Section or Schedule of or to this Agreement,

(d) descriptive headings or titles of Articles, Sections and Schedules have been inserted solely for convenience of reference and are not intended as complete or accurate descriptions of the content of those Articles, Sections or Schedules, and shall not be used in interpreting those Articles, Sections or Schedules,

(e) use of words in the singular or plural shall include the other, or with a particular gender shall include any other gender, and shall not limit the scope or exclude the application of any provision of this Agreement to any Person or Persons or circumstances as the context otherwise permits;

(f) whenever a provision of this Agreement requires an approval or consent by a Party to this Agreement:

(i) unless otherwise provided herein, that approval or consent may not be unreasonably withheld, conditioned or delayed, and

(ii) if notification of that approval or consent (or the refusal of that approval or consent) is not delivered within the applicable time limit, then, unless otherwise expressly specified herein, the Party whose consent or approval is required shall be conclusively deemed not to have provided its approval or consent,

(g) except as otherwise expressly provided herein, time periods within or following which any payment is to be made or act is to be done shall be calculated by excluding the day on which the period commences and including the day on which the period ends, and by extending the period to the next Business Day following, if the last day of the period is not a Business Day,

(h) except as otherwise expressly provided herein, whenever any payment is to be made or action to be taken under this Agreement is required to be made or taken on a day other than a Business Day, that payment shall be made or action taken on the next Business Day following that day,

(i) where the words “including” or “includes” appear in this Agreement, including the Schedules, those words mean “including (or includes) without limitation”,

(j) any references herein to an agreement, instrument or writing shall be a reference to that agreement, instrument or writing, as amended from time to time prior to the date hereof,

(k) any reference herein to a law, statute, regulation or other enactment shall be a reference to that law, statute, regulation or enactment as amended, replaced or superseded from time to time, and

(l) all references in this Agreement to the words “herein”, “hereby”, “hereof”, “hereto”, and words of similar meaning refer to this Agreement as a whole and not to any particular Article, Section or Schedule except as otherwise expressly provided herein.

1.3 Knowledge

(a) Unless and to the extent specifically provided otherwise, any reference in this Agreement (including in the Schedules) to “the knowledge” or to “the best of the knowledge” of Vendor or to any matter of which Vendor is “aware” or expressions of similar meaning will be deemed to mean the actual knowledge or awareness of the individuals named in Part 1 of Schedule 1.3 without any obligation on those individuals to make investigation or inquiry.

(b) Unless and to the extent specifically provided otherwise, any reference in this Agreement to “the knowledge” or to “the best of the knowledge” of Purchaser or to any matter of which Purchaser is “aware” or expressions of similar meaning will be deemed to mean the actual knowledge or awareness of the individuals named in Part 2 of Schedule 1.3, without any obligation on those individuals to make investigation or inquiry.

1.4 Entire Agreement

Other than the Confidentiality Agreements, this Agreement, including the Schedules and Exhibits hereto, constitutes the entire agreement among the Parties pertaining to the subject matter of this Agreement and supersedes all prior agreements, understandings, negotiations and discussions, whether oral or written, of the Parties.

1.5 Governing Law

This Agreement and any non-contractual obligation arising out of or in connection with this Agreement shall be governed by and interpreted in accordance with the laws of Alberta and the laws of Canada applicable therein, and shall be treated in all respects as an Alberta contract.

1.6 Accounting Principles

Except as otherwise expressly provided herein:

(a) references to generally accepted accounting principles means a reference to those principles as they are stated from time to time, and

(b) all accounting terms not otherwise defined in this Agreement have the meanings assigned to them,

in accordance with IFRS.

1.7 Currency Conversion

Except as otherwise expressly provided herein,

(a) all amounts referred to herein with respect to the calculation, but not the payment, of any Liabilities, Losses and Claims that would otherwise normally be denominated, quantified or calculated in Canadian Dollars shall, for purposes of this Agreement, be converted to U.S. Dollars at the Exchange Rate as of the date on which the Loss, Liability or Claim is suffered, sustained or incurred by or made against the relevant Person, and

(b) all amounts referred to herein with respect to payments required to be made in U.S. Dollars that would otherwise normally be denominated in Canadian Dollars shall, for purposes of this Agreement, be converted to and paid in U.S. Dollars at the Exchange Rate as of the date of payment.

1.8 Disclosure

Reference to any matter on any Schedule shall not be deemed to be an acknowledgement by Vendor, or to otherwise imply, that the matter meets or exceeds any applicable threshold of materiality or any other relevant threshold.

1.9 Parol Evidence

All:

(a) proposed unsigned drafts of this Agreement and of documents delivered pursuant to this Agreement, and

(b) comments thereon provided or made by any Party or its advisors directly in connection with the negotiation of this Agreement and the transactions contemplated hereby,

are confidential and agreed to have been and to be made on a “without prejudice” basis, such that in any legal proceeding the subject or outcome of which materially involves or depends on the interpretation of this Agreement or any such document, none of the Parties shall:

(c) enter any of the said comments or drafts in evidence in any such proceeding,

(d) make any of the said comments or drafts available to any party to such proceeding, or

(e) refer to any of the said comment or drafts in any such proceeding,

unless required by Law.

1.10 Schedules

The Schedules and Exhibits to this Agreement, as listed below, are attached to and are an integral part of this Agreement:

SCHEDULES

Schedule 1.1A	Confidential Contracts
Schedule 1.1B	Excluded Assets
Schedule 1.1C	Financial Statements
Schedule 1.1D	Material Facilities
Schedule 1.1E	Other Permitted Encumbrances
Schedule 1.1F	Purchased Entities, Authorized Capital and Jurisdiction of Incorporation or Formation
Schedule 1.1G	Reorganization
Schedule 1.1H	Vendor Indemnified Litigation Claims
Schedule 1.1I	Valuation of NGL Inventory
Schedule 1.1L	Leased Rail Cars
Schedule 1.1M	Interim Period Cash Flow Amount
Schedule 1.3	Individuals Having Knowledge
Schedule 3.2(d)	Canadian Withholding Tax Matters
Schedule 3.3(a)	Working Capital Statement

Schedule 4.5(e)	Conflicts with Constating Documents, Etc.
Schedule 4.7	Governmental Authorizations
Schedule 4.8	Material Consents
Schedule 4.10	Exceptions to Ordinary Course of Business, Compliance with Applicable Laws and Environmental Laws and No Material Change
Schedule 4.11	Leased Entity Assets
Schedule 4.13(b)	Defaults Under Governmental Authorizations
Schedule 4.14(a)	Material Contracts
Schedule 4.14(c)	Defaults Under Material Contracts
Schedule 4.15	Powers of Attorney
Schedule 4.16	Futures Transactions
Schedule 4.17	Certain Material Obligations and Authorizations for Expenditure
Schedule 4.18	Guarantees
Schedule 4.19	Indebtedness for Borrowed Money
Schedule 4.21(a)	Environmental Orders
Schedule 4.22(a)	Open Litigation Claims
Schedule 4.24(a)	Entity IP
Schedule 4.24(c)	IP Infringement Claims, Etc.
Schedule 4.25(a)	Tax Audits
Schedule 4.25(d)	Tax Objections and Appeals
Schedule 6.10(f)	Pre-Closing Curative Matters
Schedule 9.10	Employee Matters
Schedule 9.11	Vendor’s Insurance
Schedule 9.17	IT Related Matters
Schedule 9.24(a)	Accounting Information Required After Signing of the Agreement
Schedule 9.24(b)	Additional Financial Information
Exhibit A	[Intentionally Deleted]
Exhibit B	Form of Excluded Owned IP License
Exhibit C	Form of Litigation Support Agreement
Exhibit D	Form of Transition Services Agreement

1.11 Interpretation if Closing Does Not Occur

If Closing does not occur, each provision of this Agreement which presumes that Purchaser has acquired the Shares shall be construed as having been contingent on Closing having occurred.

1.12 Conflicts

Except as otherwise expressly provided herein, if there is any conflict or inconsistency between a provision of the body of this Agreement and that of a Schedule or a Closing Document, the provision of the body of this Agreement shall prevail.

ARTICLE 2
PURCHASE AND SALE

2.1 Actions by Vendor and Purchaser Regarding Purchase

(a) Subject to Section 2.1(b) and the other terms and conditions of this Agreement, at the Closing Time:

(i) Vendor shall sell the Shares to Purchaser and Purchaser shall purchase the Shares from Vendor,

(ii) Purchaser shall pay the Purchase Price to Vendor, and

(iii) each Party shall deliver to the other Party all documents required to be delivered by it pursuant to Article 7 or Article 8, as the case may be.

(b) The Parties agree that if the Closing Date is not a Business Day, then:

(i) the Closing Consideration and the documents required to be delivered pursuant to Article 7 and Article 8 shall be delivered as follows:

(A) the Closing Consideration shall be delivered by Purchaser, and the Share Documents shall be delivered by Vendor, to one or more of the Escrow Agents;

(B) the documents required to be delivered pursuant to Section 7.9 by Vendor, other than the Share Documents, shall be delivered by Vendor to Purchaser's Counsel; and

(C) the documents required to be delivered pursuant to Section 8.9 by Purchaser shall be delivered by Purchaser to Vendor's Counsel;

in each case on the Business Day immediately preceding the Closing Date to be held in escrow by the Escrow Agents, Purchaser's Counsel or Vendor's Counsel as the case may be pursuant to the Escrow Agreements by the Escrow Agents and by counsel upon mutually agreed upon escrow conditions, in each case, giving effect to the terms of this Section 2.1(b),

(ii) at the Closing Time, if the Vendor's Conditions have been satisfied or waived by the Vendor in accordance with this Agreement, Vendor shall so notify each of the Escrow Agent and Purchaser's Counsel in writing (with a copy to the Purchaser), and, in like manner, if the Purchaser's Conditions have been satisfied or waived by Purchaser in accordance with this Agreement, Purchaser shall so notify each of the Escrow Agent and Vendor's Counsel in writing (with a copy to the other Vendor),

(iii) if the Vendor's Conditions and the Purchaser's Conditions have been satisfied or waived by the applicable Party and notice thereof given by both Parties in writing as contemplated by Section 2.1(b)(ii), then on the Business Day next following the Closing Date, the Escrow Agent and Vendor's Counsel, as applicable, shall release to Purchaser the Share Documents and the other Closing Documents to which Purchaser is entitled hereunder, and the Escrow Agents and Purchaser's Counsel, as applicable, shall release to Vendor the Closing Consideration and the other Closing Documents to which Vendor is entitled hereunder, provided that no Closing Documents, including the Share Documents, shall be released from escrow until Vendor has confirmed receipt of the Closing Consideration and has so notified the Escrow Agents and Purchaser's Counsel (which Vendor agrees to do promptly upon receiving confirmation of receipt of the Closing Consideration) at which time such Closing Documents, including the Share Documents, shall be released to the Parties as provided above.

(iv) upon release of the documents and payments as contemplated by and in accordance with Section 2.1(b)(iii), Closing shall be deemed to have occurred at the Closing Time and legal title to and beneficial ownership of the Shares shall be deemed to have passed to Purchaser at the Closing Time and all right, title and interest in and to the Closing Consideration shall be deemed to have passed to Vendor at the Closing Time, and

(v) if notices by both Purchaser and Vendor are not given pursuant to Section 2.1(b)(ii) at the Closing Time, then, on the Business Day next following the Closing Date, the Escrow Agent and Vendor's Counsel, as applicable, shall return to Purchaser the Closing Consideration and the other Closing Documents delivered by Purchaser in escrow, and the Escrow Agent and Purchaser's Counsel, as applicable, shall return to Vendor the Share Documents and the other Closing Documents delivered by Vendor in escrow, without prejudice to the right of either Party to seek such remedies as may be available to it under Article 12 as a result of Closing having failed to occur.

2.2 Place of Closing

The Closing shall take place at the Closing Time at the principal business office of Vendor in Rotterdam, Netherlands, and the offices of Vendor's Counsel in Calgary, Alberta, or at such other place as may be agreed upon in writing by Vendor and Purchaser. The Closing Documents referred to in Section 7.9(a) to (d) and Section 8.9(b) shall be delivered at Rotterdam, Netherlands and the remaining Closing Documents shall be delivered in Calgary, Alberta.

2.3 Tender

Any tender of documents or money under this Agreement may be made on the Parties or their respective counsel and, except as otherwise expressly provided herein, money shall be tendered by wire transfer of immediately available funds to the account specified by the Party to which payment is being made. Notwithstanding anything to the contrary herein contained, Closing shall be deemed not to have occurred until, in respect of any wire transfer of funds to be effected at or before the Closing Time, the recipient of such wire transfer shall have received confirmation from its bank of the receipt of such funds.

2.4 Escrow Agreement

The Parties shall use their utmost good faith to negotiate and enter into one or more Escrow Agreements and agree upon escrow arrangements among counsel providing for the matters contemplated in Section 2.1(b) within fifteen (15) Business Days of the date hereof.

ARTICLE 3
PURCHASE PRICE

3.1 Purchase Price

The amount payable by Purchaser to Vendor for the Shares (the "**Purchase Price**") shall be an amount equal to U.S.$1,665,800,000 (the "**Base Price**"), plus an amount equal to the Base Price multiplied by the Interest Rate multiplied by a fraction the numerator of which is the number of days from and including the Effective Date to but excluding the Closing Date and the denominator of which is 365.

The Purchase Price shall be subject to adjustment as expressly provided herein.

3.2 Payment of Purchase Price and Interim Cash Flow Amount

(a) The Purchase Price shall be paid by Purchaser to Vendor as follows:

(i) on execution and delivery of this Agreement, Purchaser shall pay to Vendor, or such other Person as Vendor directs in writing, U.S.$50,000,000 (the "**Deposit**"), provided however, that if this Agreement is executed on a day other than a Business Day or after-hours on a Business Day, Purchaser shall deliver the Deposit to Vendor, or such other Person as Vendor directs in writing, at the designated bank account before 12:00 noon (Calgary time) on the next Business Day, failing which Vendor may terminate this Agreement, and

(ii) subject to Section 2.1(b), at the Closing Time, Purchaser shall pay to Vendor, or such other Person as Vendor directs in writing, an amount (the "**Closing Consideration**") equal to the Purchase Price minus the Deposit, together with all interest accrued on the Deposit net of any withholding tax applicable to such interest.

Subject to Section 2.1(b), at the Closing Time, the Deposit, together with all interest accrued thereon net of any applicable withholding tax applicable to such interest in accordance with Section 3.2(b), shall be retained by Vendor and applied towards payment of the Purchase Price.

(b) The Deposit shall accrue interest at the Interest Rate. Vendor will withhold and remit to the applicable Governmental Authority tax on such interest unless Purchaser provides appropriate documentation before the Closing Time that such withholding is not required.

(c) Each of the Parties agrees to the terms and conditions set forth in Schedule 3.2(d). Subject to compliance by Vendor with the terms and conditions set forth in Schedule 3.2(d), no amount of the Purchase Price, or any adjustments thereto, shall be subject to any withholding on account of Taxes or otherwise.

(d) At least five (5) Business Days before the Closing Date, Vendor shall deliver to Purchaser wire transfer instructions for the payment of the Closing Consideration.

(e) Vendor shall cause the Closing Interim Cash Flow Amount (if positive) to be paid to the Corporation by wire transfer of immediately available funds to the Corporation not later than the Business Day immediately before the Closing Date. At least five (5) Business Days before the Closing Date, Vendor shall establish a bank account in the name of the Corporation for this purpose and, subject to Closing occurring, at the Closing Time the signing authority for such account shall be changed from Vendor's representatives to Purchaser's representatives. Vendor shall be entitled to cause the Corporation to pay to Vendor, prior to the Closing Date, the Closing Interim Cash Flow Amount (if negative).

3.3 Post Closing Adjustment to the Working Capital Amount

(a) Schedule 3.3(a) contains a statement (the "**Working Capital Statement**") setting forth the Working Capital Amount as determined by Vendor as at the Effective Time. Within thirty (30) Business Days of the date hereof, Vendor will deliver to Purchaser general ledger detail for each line item in the Working Capital Statement and provide Purchaser with such additional detail with respect thereto as reasonably requested by Purchaser within a reasonable period of time following the request, but in no event later than 10 Business Days following such request.

(b) If, after the date hereof, Purchaser disputes Vendor's determination of the Working Capital Amount as set forth in the Working Capital Statement, Purchaser will so notify Vendor, in writing, within 90 days of the receipt of the general ledger detail described in Section 3.3(a) (the "**Purchaser's Objection**"). The Purchaser's Objection will set forth a specific description of the basis of the dispute and the adjustments to the Working Capital Statement that Purchaser believes should be made. If Purchaser does not deliver a Purchaser's Objection within that 90 day period, the Working Capital Statement shall be deemed to be conclusive and binding on the Parties.

(c) Vendor will have 60 days (the "**Vendor's Review Period**") from receipt of the Purchaser's Objection to review the Purchaser's Objection and respond to it in writing. If Vendor does not respond in writing to the Purchaser's Objection within the Vendor's Review Period, the Working Capital Statement shall be adjusted in accordance with the Purchaser's Objection and shall be deemed to be conclusive and binding on the Parties. If Vendor does respond in writing within the Vendor's Review Period, then the Parties will thereafter attempt in good faith to reach an agreement with respect to any matters in dispute. If Vendor and Purchaser reach such agreement, the Working Capital Statement shall be adjusted in accordance with such agreement and shall be deemed to be conclusive and binding on the Parties. If Vendor and Purchaser are unable to resolve the matters in dispute within fifteen (15) days following the end of the Vendor's Review Period, either Vendor or Purchaser may notify the other in writing of their wish to have the matter finally resolved by Expert Determination pursuant to Section 3.5.

(d) In the event the Working Capital Amount set out in the Working Capital Statement as finally settled pursuant to this Section 3.3 or Section 3.5, as the case may be, is greater than U.S.$10,000,000, Purchaser shall pay to Vendor, and the Purchase Price shall be increased by, the amount by which the Working Capital Amount is greater than zero. In the event the Working Capital Amount set out in the Working Capital Statement as finally settled pursuant to this Section 3.3 or Section 3.5, as the case may be, is less than negative U.S.$10,000,000, Vendor shall pay to Purchaser, and the Purchase Price shall be decreased by, the amount by which the Working Capital Amount is less than zero. No payment shall be required to be made under this Section 3.3(d) unless Closing occurs.

(e) Any payment required pursuant to Section 3.3(d) shall be made within fifteen (15) Business Days following the final determination of the Working Capital Amount in accordance with this Section 3.3 or Section 3.5, together with interest thereon at the Interest Rate from and including the Effective Date to but excluding the date of payment. No further adjustments shall be made to the Purchase Price with respect to the Working Capital Amount. Any such payment (excluding the part thereof that is interest) shall be treated by Vendor and Purchaser as an adjustment to the Purchase Price. Any interest paid by Purchaser shall be regarded as interest payable in consideration of the delayed payment of the Purchase Price at Closing.

(f) Vendor and Purchaser shall cooperate, and shall cause the Purchased Entities to cooperate, with each other, to facilitate the settlement of the Working Capital Statement in accordance with this Section 3.3 or Section 3.5. During the period of time from and after the date hereof through to the time the Working Capital Amount is finally determined in accordance with this Section 3.3 or Section 3.5, Vendor or Purchaser shall afford, and cause the Purchased Entities to afford, to the Accounting Firm, the Parties and the Parties' Related Parties, in connection with the settlement of the Working Capital Statement as contemplated by this Section 3.3 or Section 3.5, reasonable access during normal business hours to all the Books and Records, properties, personnel and work papers in their possession relevant thereto.

(g) For greater certainty, no adjustment pursuant to this Section 3.3 shall be subject to any of the thresholds, deductibles or caps set forth in Articles 6 or 10.

(h) The Parties acknowledge and agree that the final determination of the Working Capital Amount may not occur until after Closing and any dispute with respect to the Working Capital Statement shall not delay Closing.

3.4 Interim Cash Flow Adjustment

(a) Vendor shall prepare the Interim Period Financial Statements on a basis consistent with the Financial Statements and on a basis that fairly presents, in all material respects, the financial condition and results of operations for the Business as at the date thereof, and for the Interim Period. Vendor shall also prepare a draft statement (the "**Interim Period Cash Flow Statement**") setting forth the calculation, for the purpose of Closing, of the Interim Cash Flow Amount in accordance with Schedule 1.1M (the "**Closing Interim Cash Flow Amount**"). Vendor shall deliver the draft Interim Period Financial Statements and a draft Interim Period Cash Flow Statement to Purchaser not later than five (5) Business Days prior to the Closing Date. The draft Interim Period Financial Statements and the draft Interim Period Cash Flow Statement shall, to the extent necessary, use estimates made in good faith by Vendor. Vendor shall deliver final Interim Period Financial Statements and a final Interim Period Cash Flow Statement not later than the later of: (i) sixty (60) days after the Closing Date, and (ii) fourteen (14) days after the Working Capital Statement is finally settled pursuant to Section 3.3 or Section 3.5. Purchaser shall provide, and shall cause the Purchased Entities to provide, all such access to books and records and personnel as Vendor reasonably requires to prepare the final Interim Period Financial Statements and a final Interim Period Cash Flow Statement.

(b) If Purchaser disputes Vendor's determination of the Interim Cash Flow Amount as set forth in the final Interim Period Cash Flow Statement, Purchaser will so notify Vendor, in writing, within 180 days from the date on which Vendor delivers to Purchaser the final Interim Period Cash Flow Statement (the "**Purchaser's ICF Objection**"). The Purchaser's ICF Objection shall set forth a specific description of the basis of the dispute and the adjustments to the Interim Period Cash Flow Statement that Purchaser believes should be made. If Purchaser does not deliver a Purchaser's ICF Objection within that 180 day period, the final Interim Period Cash Flow Statement shall be deemed to be conclusive and binding on the Parties.

(c) Vendor will have 90 days ("**Vendor's ICF Review Period**") from receipt of the Purchaser's ICF Objection to review the Purchaser's ICF Objection and respond to it in writing. If Vendor does not respond in writing to the Purchaser's ICF Objection within the Vendor's ICF Review Period, the final Interim Period Cash Flow Statement shall be adjusted in accordance with the Purchaser's ICF Objection and shall be deemed to be conclusive and binding on the Parties. If Vendor does respond in writing within the Vendor's ICF Period, then the Parties will thereafter attempt in good faith to reach an agreement with respect to any matters in dispute. If Vendor and Purchaser reach such agreement, the final Interim Period Cash Flow Statement shall be adjusted in accordance with such agreement and shall be deemed to be conclusive and binding on the Parties. If Vendor and Purchaser are unable to resolve the matters in dispute within fifteen (15) days

following the end of the Vendor's ICF Period, either Vendor or Purchaser may notify the other in writing of their wish to have the matter finally resolved by Expert Determination pursuant to Section 3.5.

(d) In the event the Interim Cash Flow Amount set out in the final Interim Period Cash Flow Statement as finally settled pursuant to this Section 3.4 or Section 3.5 (the "**Final Interim Cash Flow Amount**") is greater than the Closing Interim Cash Flow Amount, Vendor shall cause to be paid to the Corporation the amount by which the Final Interim Cash Flow Amount is greater than the Closing Interim Cash Flow Amount. In the event the Final Interim Cash Flow Amount is less than the Closing Interim Cash Flow Amount, Purchaser shall pay Vendor, or cause the Corporation to pay to Vendor, the amount by which the Final Interim Cash Flow Amount is less than the Closing Interim Cash Flow Amount.

(e) Any payment required pursuant to Section 3.4(d) shall be made within fifteen (15) Business Days following the final determination of the Interim Period Cash Flow Amount in accordance with this Section 3.4 or Section 3.5, together with interest thereon at the Interest Rate from and including the Effective Date to but excluding the date of payment. Any such payment (excluding the part thereof that is interest) shall be treated by Vendor and Purchaser as an adjustment to the Purchase Price. No further adjustments shall be made to the Purchase Price with respect to the Interim Period Cash Flow Amount. Any interest paid by Purchaser shall be regarded as interest payable in consideration of the delayed payment of the Purchase Price at Closing.

(f) Vendor and Purchaser shall cooperate, and Purchaser shall cause the Purchased Entities to cooperate, with each other, to facilitate the settlement of the final Interim Period Cash Flow Statement in accordance with this Section 3.4 or Section 3.5. During the period of time from and after the Closing Date through to the time the Interim Period Cash Flow Amount is finally determined in accordance with this Section 3.4 or Section 3.5, Vendor and Purchaser shall afford, and Purchaser shall cause the Purchased Entities to afford, to the Accounting Firm, the Parties and the Parties' Related Parties, in connection with the settlement of the final Interim Period Cash Flow Statement as contemplated by this Section 3.4 or Section 3.5, reasonable access during normal business hours to all of the Books and Records, properties, personnel and work papers relevant thereto.

(g) For greater certainty, no adjustment pursuant to this Section 3.4 shall be subject to any of the thresholds, deductibles or caps set forth in Articles 6 or 10.

3.5 Expert Determination

(a) If Vendor and Purchaser are unable to resolve matters in dispute as contemplated in Section 3.3(c) or 3.4(c) within 15 days following the end of the Vendor's Review Period or Vendor's ICF Review Period, as the case may be, either Vendor or Purchaser may notify the other in writing that the dispute shall be referred for resolution by the Accounting Firm in which case the Accounting Firm shall determine, only with respect to the remaining differences so submitted, whether and to what extent, if any, the Working Capital Statement or the final Interim Period Cash Flow Statement, as the case

may be, requires adjustment. Notwithstanding Section 9.20, which shall not apply to this Section 3.5, any dispute arising pursuant to Section 3.3(c) or 3.4(c) referred to the Accounting Firm in accordance with this Section 3.5 shall be resolved in accordance with the following:

(i) The Accounting Firm shall act as an expert (and not as an arbitrator) in making its determination (the "**Expert Determination**"). Any applicable law relating to arbitration shall not apply to the Accounting Firm or to the Expert Determination or the procedure by which the Expert Determination is reached. For the avoidance of doubt, the Expert Determination shall not be referable to arbitration pursuant to Section 9.20.

(ii) Within 5 Business Days of receiving the Accounting Firm's written confirmation and acknowledgement of its appointment to act as expert in the Expert Determination, Vendor and Purchaser shall each prepare and deliver to the Accounting Firm: (A) a written statement (such statement not to exceed 10 pages) addressing the matters in dispute; and (B) any relevant supporting documents. Vendor and Purchaser shall at the same time deliver to the respective other Party copies of its materials provided to the Accounting Firm.

(iii) The Accounting Firm shall be entitled to make a determination and issue its decision based only on the written statements and supporting documents received from Vendor and Purchaser.

(iv) For the avoidance of doubt, there shall be no unilateral communications between either Vendor or Purchaser and the Accounting Firm at any time during the Expert Determination.

(v) The Accounting Firm may obtain independent professional, legal and/or technical advice as it considers is reasonably required and it advises Vendor and Purchaser of its intention in advance of obtaining such assistance.

(vi) Vendor and Purchaser shall request that the Accounting Firm make its determination within twenty (20) Business Days after the Accounting Firm has delivered to Vendor and Purchaser the Accounting Firm's written confirmation and acknowledgement of its appointment to act as expert in the Expert Determination. Such determination shall be made in writing and shall include reasonable details regarding the reasons for the Accounting Firm's determination.

(vii) In resolving any disputed item, the Accounting Firm must not assign a value to that item greater than the greatest value for that item claimed by either Vendor or Purchaser or less than the smallest value for that item claimed by either Vendor or Purchaser. The Accounting Firm shall not have the jurisdiction to award any form of damages or costs or to award specific performance, injunctive relief or any other equitable relief, nor will the Accounting Firm have the authority to modify or amend, in any respect, the provisions of this Agreement or any related agreements.

(viii) Vendor and Purchaser agree that subject to Subsections 3.5(a)(ix) and 3.5(a)(x) below, any Expert Determination decision of the Accounting Firm made in accordance with this Section 3.5 shall be deemed to be agreed to and to be conclusive, final and binding on Vendor and Purchaser and may, where permitted and following the expiry of the ten (10) day period referred to in Section 3.5(a)(x), be filed in any court of competent jurisdiction and enforced by Vendor or Purchaser as a final judgment of such court.

(ix) Vendor or Purchaser may only challenge the Expert Determination decision of the Accounting Firm (A) for manifest error or fraud on the part of the Accounting Firm; (B) for failure by the Accounting Firm to disclose any relevant interest or duty which materially conflicts with its function as expert and/or which may prejudice the Expert Determination; or (C) by reason of the Accounting Firm having, in the Expert Determination, decided on any matter that is not, by the terms of this Section 3.5, expressly within the jurisdiction of the Accounting Firm. Notwithstanding Section 9.20 of this Agreement, any challenge permitted to be made in respect of an Expert Determination decision of the Accounting Firm shall be made in the court of competent jurisdiction sitting in Calgary, Alberta.

(x) The Accounting Firm may, on its own initiative or at the written request of a Party (which must also be given to the other Party) correct, in a revised and replacement Expert Determination, any mathematical or typographical errors, in the Expert Determination, provided that no such correction shall be made unless it is made and the revised and replacement Expert Determination is delivered to the Parties within ten (10) days following the day upon which the Expert Determination decision was delivered to the Parties.

(xi) For the avoidance of doubt: (A) Section 9.20 of this Agreement shall not apply to challenges to Expert Determination decisions; and (B) apart from challenges to Expert Determination decisions of the Accounting Firm and the resolution of the disputes provided for in Section 8.5 of the Litigation Support Agreement**,** Vendor and Purchaser do not submit to the jurisdiction of the Alberta courts for purposes of resolving any disputes or disagreements that may arise out of, pursuant to or in connection with this Agreement.

(xii) Vendor and Purchaser will each pay one half of the fees and disbursements incurred by the Accounting Firm concerning any Expert Determination referred to the Accounting Firm.

(b) The Working Capital Statement or the final Interim Period Cash Flow Statement, as the case may be, shall be revised to reflect any revisions as agreed to by the Parties or as determined by the Accounting Firm.

3.6 Purchase Price Allocation

Prior to the Closing Time, Vendor and Purchaser shall use reasonable and good faith efforts to agree in writing to an allocation of the Purchase Price consistent with Section 1060 of the Code and the U.S. Treasury regulations thereunder (the "**Purchase Price Allocation**"). In the event

that agreement on Purchase Price Allocation is not reached by the Closing Time, neither Vendor nor Purchaser shall have any further obligation to attempt to agree on a Purchase Price Allocation.

ARTICLE 4
REPRESENTATIONS AND WARRANTIES OF VENDOR

Vendor represents and warrants to Purchaser that:

4.1 Incorporation and Registration

(a) Vendor is a duly incorporated corporation, validly existing under the laws of the Netherlands.

(b) Vendor Guarantor is a duly incorporated corporation and is validly existing under the laws of the State of Indiana.

(c) At the Closing Time, each of the Purchased Entities will be a corporation or other entity duly incorporated or formed and validly existing under the laws of the jurisdiction of its incorporation or formation as set forth in Schedule 1.1F and will have all necessary corporate or other power and capacity to own and lease its property and assets and to carry on the business conducted by it.

(d) At the Closing Time, each of the Purchased Entities will, in all material respects, be in good standing under the laws of the jurisdiction of its incorporation or formation and neither the nature of the business of, nor the locations or character of the property and assets owned or leased by, any of the Purchased Entities will require any of the Purchased Entities to be registered, licensed or otherwise qualified as an extra-provincial or foreign corporation in any jurisdiction where it is not so registered, licensed or qualified.

4.2 Capitalization and Ownership

(a) At the Closing Time, the Corporation shall be a direct wholly-owned subsidiary of Vendor and each of the other Purchased Entities shall be a direct or indirect wholly-owned subsidiary of the Corporation.

(b) Other than the other Purchased Entities and the ownership of ten (10) shares in the capital of Alberta One-Call Corporation (representing a 10.96% equity ownership interest therein), at the Closing Time, the Corporation shall have no subsidiaries.

4.3 Right to Sell Shares

(a) At the Closing Time, Vendor shall have the exclusive right to sell, assign and transfer the Shares as provided in this Agreement.

(b) At the Closing Time, any restrictions on the transfer of the Shares that are set out in the Constating Documents of the Corporation will have been complied with so as to permit the transfer of the Shares to Purchaser.

(c) On the completion of the Purchase, Purchaser shall acquire from Vendor good legal and beneficial title to the Shares free and clear of all Encumbrances other than restrictions on transfers set out in the Constating Documents of the Corporation and any Encumbrances arising out of any action taken by Purchaser or any of its Affiliates.

(d) As of the date hereof, no person, other than Purchaser pursuant to this Agreement, has any agreement or option or any right or privilege (whether by Law, pre-emptive or contractual) capable of becoming an agreement or option for the purchase or acquisition from Vendor of any of the Shares.

(e) At the Closing Time, no person, other than Purchaser pursuant to this Agreement, shall have any agreement or option or any right or privilege (whether by Law, pre-emptive or contractual) capable of becoming an agreement or option for the purchase or acquisition from Vendor of any of the Shares.

4.4 Shares of Purchased Entities

(a) At the Closing Time, the authorized capital of each of the Purchased Entities, other than Dome Petroleum LLC and 123456 Delaware LLC, shall be as set forth in Schedule 1.1F and the Shares shall be the only issued and outstanding shares in the capital of the Corporation.

(b) At the Closing Time, all of the issued and outstanding shares or member interests (as applicable) of the Purchased Entities shall have been duly and validly issued and shall be outstanding as fully paid and non-assessable shares or member interests, as the case may be.

(c) At the Closing Time, all of the issued and outstanding shares of the Corporation shall be held by Vendor, and all of the issued and outstanding shares and member interests (as the case may be) of the other Purchased Entities shall be held by the Corporation or one or more of the directly or indirectly wholly-owned subsidiaries of Corporation, in each case free and clear of all Encumbrances other than restrictions on transfers set out in the Constating Documents of the Purchased Entities and any Encumbrances arising out of any action taken by Purchaser or any of its Affiliates.

(d) At the Closing Time, there will be no contract, option or other right (including preferential or other similar rights) of any Person binding upon, or which may become binding upon, the registered and beneficial owner of the shares or member interests (as applicable) of the Purchased Entities to sell, assign, pledge, charge, mortgage or transfer or in any other way dispose of or encumber any such shares other than, in the case of the Shares, rights in favour of Purchaser pursuant to this Agreement.

(e) At the Closing Time, there will be no securities convertible, exchangeable or exercisable into, or rights, options or warrants to purchase or otherwise acquire, any unissued shares or other ownership interests in the capital of any of the Purchased Entities.

(f) There exists no shareholder or other agreement or declaration which affects the transferability of the Shares, and there exists no voting trust agreement, unanimous shareholder agreement, share pooling agreement or other Contract restricting or otherwise relating to voting or dividend rights with respect to the Shares or the shares or member interests (as applicable) of any of the Purchased Entities.

4.5 Due Authorization

(a) Vendor has all necessary corporate power, authority and capacity to enter into this Agreement and to carry out its obligations hereunder.

(b) Vendor Guarantor has all necessary corporate power, authority and capacity to enter into the Vendor Parent Guarantee and to carry out its obligations under the Vendor Parent Guarantee.

(c) The execution and delivery of this Agreement and the performance of Vendor’s obligations under this Agreement have been duly authorized by all necessary corporate action on the part of Vendor.

(d) The execution and delivery of the Vendor Parent Guarantee and the performance of Vendor Guarantor’s obligations under the Vendor Parent Guarantee have been duly authorized by all necessary corporate action on the part of Vendor Guarantor.

(e) Except as described or referred to in Schedule 4.5(e), and subject to satisfaction of the Regulatory Condition, neither the execution and delivery of this Agreement by Vendor, nor the performance of Vendor’s obligations under this Agreement, nor the consummation of the Reorganization will conflict with, or result in the violation, termination or breach of, or render Vendor or the Purchased Entities in default of, or result in the termination or in a right of termination of, or accelerate the performance required by, or result in being declared void, voidable or without further binding effect, any of the terms, conditions or provisions of:

(i) the Constating Documents of Vendor or any of the Purchased Entities,

(ii) any material Contract to which Vendor is a party or by which Vendor is bound,

(iii) any Applicable Laws, Environmental Laws or Governmental Authorizations applicable to Vendor.

(f) Neither the execution and delivery of the Vendor Parent Guarantee by Vendor Guarantor, nor the performance of Vendor Guarantor's obligations under the Vendor Parent Guarantee will conflict with, or result in the violation or breach of, or render Vendor Guarantor in default of, or result in the termination or cancellation or in a right of termination or cancellation of, or accelerate the performance required by, or result in being declared void, voidable or without further binding effect, any of the terms, conditions or provisions of:

(i) the Constating Documents of Vendor Guarantor,

(ii) any material Contract to which Vendor Guarantor is a party or by which Vendor Guarantor is bound, or

(iii) any Applicable Laws, Environmental Laws or Governmental Authorizations applicable to Vendor Guarantor.

4.6 Enforceability of Obligations

(a) This Agreement constitutes a legal, valid and binding obligation of Vendor, enforceable against Vendor in accordance with its terms, subject to bankruptcy, winding-up, insolvency, moratorium, arrangement, reorganization and other similar laws affecting creditors' rights generally and to general principles of equity.

(b) The Vendor Parent Guarantee constitutes a legal, valid and binding obligation of Vendor Guarantor, enforceable against Vendor Guarantor in accordance with its terms, subject to bankruptcy, winding-up, insolvency, moratorium, arrangement, reorganization and other similar laws affecting creditors' rights generally and to general principles of equity.

4.7 Required Approvals

Except as described or referred to in Schedule 4.7, and except for the Required Approvals and any Governmental Authorizations normally granted by the relevant Governmental Authority after Closing, and except for Governmental Authorizations the failure of which to obtain, either individually or in the aggregate, would not reasonably be expected to have a Material Adverse Effect, no Governmental Authorizations are:

(a) required on the part of Vendor in connection with the Purchase or Vendor's performance of its obligations under this Agreement,

(b) required on the part of the Purchased Entities in connection with the Purchase or to preserve the rights of the Purchased Entities under any existing Governmental Authorizations, or

(c) required on the part of Vendor Guarantor in connection with the performance of its obligations under the Vendor Parent Guarantee.

4.8 Material Consents

Schedule 4.8 describes, refers to or lists all approvals or other consents required to be obtained under Material Contracts as a result of the transactions contemplated herein so as to (i) preserve the rights of the Purchased Entities under such Material Contracts, or (ii) not trigger any rights of any Person under any Material Contract that could vest if a change in control of any Purchased Entity occurs.

4.9 Financial Statements

The Financial Statements (subject to usual year-end adjustments in the case of the Interim Financial Statements and taking into account the basis on which the Financial Statements were prepared as described in the notes to the annual financial statements contained in the Financial Statements and the other notes to the Financial Statements):

(a) are complete and accurate in all material respects, and

(b) fairly present, in all material respects, the financial condition and results of operations for the Business as at the respective dates of, and for the respective periods referred to in, such financial statements,

in accordance with IFRS consistently applied during the periods presented.

Purchaser acknowledges that as at the dates of and for the periods referred to in the Financial Statements certain Excluded Assets were included in the Business as at such dates and for such periods.

4.10 Business Carried on in the Ordinary Course; Compliance with Applicable Laws and Environmental Laws

Except as described or referred to in Schedule 4.10, or as otherwise permitted or contemplated by this Agreement (including the Permitted Pre-Closing Actions), since September 30, 2011 to the date hereof:

(a) the Business has been carried on in the Ordinary Course of Business,

(b) the Business has been conducted in compliance, in all material respects, with all Applicable Laws and Environmental Laws,

(c) none of the Purchased Entities has acquired or disposed of or agreed to acquire or dispose of any Entity Assets other than in the Ordinary Course of Business, nor have any of the Purchased Entities incurred or assumed or agreed to incur or assume any liabilities other than in the Ordinary Course of the Business, and

(d) there has been no material adverse change in the financial condition or in the assets or liabilities of the Business arising from developments specific to the Business not generally affecting other entities similarly situated in the NGLs industry in Canada or the United States.

4.11 Entity Assets

(a) Except for Permitted Encumbrances and those Encumbrances created after the date hereof in compliance with Sections 9.1 or 9.2:

(i) Vendor does not warrant title to the Entity Assets, but does warrant that the Purchased Entities own their interests in the Entity Assets (which, in the case of the Material Facilities, are the undivided percentage ownership interests set forth in Schedule 1.1D and, in the case of the real property or leases thereof on or in which the Material Facilities that are operated by one of the Purchased Entities are located (other than pipeline rights of way and easements), are the undivided percentage ownership interests set forth in Schedule 4.11) (collectively the "**said interests**"), free and clear of all Encumbrances and Claims created by, through or under Vendor or any of its Affiliates or any of the Purchased Entities, and

(ii) neither Vendor nor the Purchased Entities have committed any act or omission whereby any of the said interests of the Purchased Entities to the Entity Assets or any part or portion thereof may be cancelled or determined.

(b) Schedule 4.11 sets forth a true and complete list of (i) all leased real property on or in which the Material Facilities and storage caverns are located that are Leased Entity Assets excluding pipeline rights of way and easements, and (ii) the leases under which they are held, other than the real property and leases referred to in Section 4.11(a).

4.12 Operation of Entity Assets

The Entity Assets, in respect of which any of the Purchased Entities is the operator, and, to Vendor's knowledge, as at the date hereof, the Entity Assets, in respect of which none of the Purchased Entities is the operator, have been operated in accordance with good NGLs industry practice in Canada or, where applicable, the United States in effect at the time that the operations were conducted except to the extent failure to have done so would not reasonably be expected to have a Material Adverse Effect.

4.13 Governmental Authorizations; Compliance Therewith

(a) The Purchased Entities hold all Governmental Authorizations required under Applicable Law to own or operate the Entity Assets owned or operated by them except to the extent failure to hold same would not reasonably be expected to have a Material Adverse Effect.

(b) Except as described or referred to in Schedule 4.13(b), to Vendor's knowledge, none of the Purchased Entities is in default under any Governmental Authorization referred to in Section 4.13(a) except to the extent such defaults, individually or in the aggregate, would not reasonably be expected to have a Material Adverse Effect.

4.14 Material Contracts

(a) Schedule 4.14(a) includes, as at November 30, 2011, a complete and accurate list of all Material Contracts, a copy of each of which, other than the Confidential Contracts, has been made available to the Purchaser.

(b) Each of the Material Contracts (excluding non-contractual understandings and arrangements and any Material Contracts which have not been fully executed by the parties thereto) is enforceable in accordance with its terms, subject to bankruptcy, winding-up, insolvency, moratorium, arrangement, reorganization and other similar laws affecting creditors' rights generally, and to general principles of equity.

(c) Except as described or referred to in Schedule 4.14(c), none of the Purchased Entities, and, to the knowledge of Vendor, no other party to any Material Contract, is in default under any Material Contract, except to the extent such defaults, individually or in the aggregate, would not reasonably be expected to have a Material Adverse Effect.

4.15 Powers of Attorney

Except to the extent referred to, described or listed herein or in Schedule 4.15, at the Closing Time, no Person will hold any outstanding power of attorney granted by any of the Purchased Entities other than powers of attorney granted by one Purchased Entity to one or more of the other Purchased Entities or the Entity Employees or as may have been provided under the Title and Operating Documents and the Material Contracts.

4.16 Futures Transactions

At the Closing Time, none of the Purchased Entities will be party to any Futures Transaction, either as principal or surety, except as described, referred to or listed in Schedule 4.16.

4.17 Certain Material Obligations and Authorizations for Expenditure

(a) Except as described, referred to or listed in Schedule 4.17, and except in respect of any Permitted Pre-Closing Actions, activities in the Ordinary Course of Business and obligations under Material Contracts, none of the Purchased Entities is a party to or bound by any Contract:

(i) to acquire any shares or other securities of any corporation, partnership interests in any partnerships or any other equity interests in any other Person,

(ii) to merge or consolidate with any other Person,

(iii) to sell or acquire any assets relating to the Business having a fair market value, individually, in excess of U.S.$1,000,000, or

(iv) to otherwise capitalize or invest in any business.

(b) Except as described, referred to or listed in Schedule 4.17, and except for those individual authorizations for expenditure relating to the Business which do not require expenditures by any of the Purchased Entities in an amount in excess of U.S.$1,000,000 (net to any Purchased Entity), as at the date of this Agreement, none of the Purchased Entities is in receipt of any outstanding authorization for expenditure in respect of jointly owned assets pursuant to which expenditures are required to be made in respect of the Business.

4.18 Guarantees

Except as described or referred to in Schedule 4.18, at the Closing Time, none of the Purchased Entities will be a party to any Guarantee.

4.19 Borrowed Money

Except as described or referred to in Schedule 4.19, and except for any indebtedness owed to another Purchased Entity at the Closing Time, none of the Purchased Entities will, at the Closing Time, have any indebtedness for borrowed money.

4.20 Minute Books

The minute books of each of the Purchased Entities are complete and accurate in all material respects.

4.21 Environmental Matters

(a) Except as described or referred to in Schedule 4.21(a):

(i) as at the date hereof, neither Vendor nor any of the Purchased Entities has received any outstanding Environmental Order which gives rise to Purchaser Indemnified Environmental Liabilities and which either requires any work, repairs, construction or capital expenditures or has not been complied with in all material respects, except, in either such case, for any Environmental Orders the failure with which to have complied, individually or in the aggregate, would not reasonably be expected to have a Material Adverse Effect,

(ii) the Purchased Entities are in compliance with Environmental Laws in respect of the operation of the Entity Assets and the Business except to the extent failure to be in compliance would not reasonably be expected to have a Material Adverse Effect,

(iii) all known spills or similar incidents pertaining to or affecting the Entity Assets or the Business have been reported to the appropriate Governmental Authority to the extent required by Applicable Law except to the extent failure to have done so would not reasonably be expected to have a Material Adverse Effect, and

(iv) all waste disposal pertaining to or affecting the Entity Assets or the Business has been and is being conducted in accordance with Environmental Laws except to the extent failure to do so would not reasonably be expected to have a Material Adverse Effect.

(b) Except as specifically set forth in this Section 4.21, Vendor makes no representations or warranties with respect to any Environmental Matters, any Environmental Liabilities or any Abandonment and Reclamation Obligations, and no other provision of this Agreement shall in any way be interpreted as providing for or making any such representations or warranties.

4.22 Litigation and Unsatisfied Judgements (other than Tax)

(a) As of November 30, 2011, Schedule 1.1H and Schedule 4.22(a), together, set forth a list of all open litigation Claims, other than Tax Claims, that have been served on, or, to Vendor's knowledge, that are threatened in writing against, any of the Purchased Entities where the amounts claimed or threatened exceeds or could reasonably be expected to exceed $300,000. Vendor makes no representation or warranty with respect to the validity or potential outcome of any of those Claims.

(b) There are no unsatisfied judgments against any of the Purchased Entities or any consent decrees or injunctions to which any of the Purchased Entities is subject.

4.23 Employee Matters

(a) (i) All material terms of all Employment Agreements with the Purchased Entities or their Affiliates with respect to all of the Entity Employees have been disclosed or made available to Purchaser other than those terms contemplated by Section 4.23(a)(ii), (ii) Vendor will, not later than thirty (30) days after the date of this Agreement, have provided Purchaser with all material current information related to the terms of employment of the Entity Employees, including without limitation for each Entity Employee their salary or wage, vacation entitlement and accumulated but unused vacation entitlement under the Employee Benefit Arrangements of Vendor and its applicable Affiliates, to enable the Purchaser to form and communicate to the Entity Employees terms of employment from and after Closing that meet the terms of Schedule 9.10 Part A and Schedule 9.10 Part B; historical information, including but not limited to, performance, disciplinary, attendance, medical records and personnel files generally will only be provided for Canadian Entity Employees at Closing and will not be provided for U.S. Entity Employees, (iii) copies of all written Employment Agreements between the Purchased Entities and Entity Employees which contain a fixed term of employment (but not including, for clarity, employment agreements in letter form with employees which do not contain a fixed term of employment) have been made available to Purchaser, and (iv) none of the Employment Agreements between the Purchased Entities and the Entity Employees provide for change of control payments (which, for clarity, shall not include safety and operations bonuses payable on closing of the Purchase).

(b) All material terms of all Employee Benefit Arrangements of Vendor and its applicable Affiliates have been disclosed to or made available to Purchaser.

(c) At the Closing Time, the Purchased Entities will be in compliance in all material respects with all Employee Obligations.

(d) The Purchased Entities are not party to or bound by or subject to any collective bargaining agreement or similar arrangement with any labour union or employee association other than any agreement or arrangement, or a description of the material terms thereof, which has been disclosed or made available to Purchaser.

(e) No collective bargaining agreement is being negotiated by any of the Purchased Entities and there are no labour certification proceedings outstanding in respect of any of the employees of any of the Purchase Entities, and, to the knowledge of Vendor, there are no attempts to organize or certify any Entity Employees.

(f) There are no material claims or complaints, other than those in the Ordinary Course of Business, against any of the Purchased Entities relating to employment standards, occupational health and safety, human rights, privacy, labour relations, workers compensation, pay equity or employment equity, and none of the Purchased Entities is subject to any strikes, labour disputes or grievances.

(g) The Purchased Entities have complied in all material respects with all Applicable Laws relating to employment and occupational health and safety, and there are no material

liens or trust obligations of the Purchased Entities arising in connection with workers' compensation, employment insurance, or pension or employment Laws.

(h) Appendix A of Part A of Schedule 9.10 and Appendix B of Part B of Schedule 9.10 contain, as of the date hereof, a complete and accurate record in all material respects of all the information listed in such Appendices with respect to the Entity Employees.

4.24 Intellectual Property

(a) Schedule 4.24(a) describes, refers to or lists (i) all material Intellectual Property that will be owned by a Purchased Entity at the Closing Time, and (ii) all material Intellectual Property that will be used by a Purchased Entity under a license agreement between a Purchased Entity and a Person other than Vendor or any of its Affiliates at the Closing Time (collectively, "**Entity IP**"). Vendor shall be entitled to revise Schedule 4.24(a) from time to time prior to Closing to reflect changes in Entity IP made in the Ordinary Course of Business by Vendor and its Affiliates and, upon delivery of a revised Schedule 4.24(a) to Purchaser, the revised Schedule 4.24(a) shall supersede and replace the Schedule 4.24(a) so revised, provided that such changes in Entity IP shall not result in material reductions or alterations in the functionality of the Dedicated ERP Environment.

(b) Except for Excluded IP, the Entity IP is all of the material Intellectual Property that will be required by the Purchased Entities to carry on the Business immediately following Closing substantially as such Business was carried on by the Purchased Entities immediately prior to Closing.

(c) Except as set forth in Schedule 4.24(c), as at the date hereof:

(i) neither Vendor nor any of its Affiliates is party to any action or proceeding which involves a Claim by any of them that the use of any Intellectual Property by a third party infringes or misappropriates any Entity IP,

(ii) neither Vendor nor any of its Affiliates is a party to any action or proceeding, and, to Vendor's knowledge, no such action or proceeding is threatened, which involves a Claim by a third party that the use of any Entity IP infringes or misappropriates the Intellectual Property of such third party, and

(iii) neither Vendor nor any of its Affiliates is party to any action or proceeding and, to Vendor's knowledge, no such action or proceeding is threatened, which involves a Claim by a third party challenging the validity or enforceability of any Entity IP.

4.25 Taxes

For the Purchased Entities that are incorporated or formed in Canada (the "**Canadian Purchased Entities**"), the representations and warranties in this Section 4.25: (i) apply only in respect of taxation years or periods ending before the Closing Date that are within the "normal reassessment period", as defined in subsection 152(3.1) of the Tax Act, of a Purchased Entity, and (ii) in respect of taxation years for any period ending before the Closing Date that are beyond the "normal reassessment period" of a Purchased Entity, apply only if the person filing a

Tax Return of a Purchased Entity in respect of such taxation year has made a misrepresentation or committed a fraud described in subparagraph 152(4)(a)(i) of the Tax Act, filed a waiver under subparagraph 152(4)(a)(ii) of the Tax Act, or if the assessment is made within the period and conditions specified under subparagraph 152(4)(b)(ii) or 152(4)(b)(iii) or the Tax Act. For Dome Petroleum LLC and 123456 Delaware LLC, the representations and warranties in this Section 4.25 apply only in respect of any period for which the applicable period of limitations has not expired.

(a) Vendor has caused the Purchased Entities to duly and timely:

(i) file all Tax Returns required to be filed by them and those Tax Returns are true, complete and accurate in all material respects,

(ii) pay all Taxes (including instalments) due and payable by them, and

(iii) collect or withhold and timely remit to the appropriate Governmental Authorities all Taxes required to be collected or withheld by them,

and, except as provided in Schedule 4.25(a), as at the date hereof, there are no audits pending or threatened in writing by any Governmental Authority against any of the Purchased Entities in respect of Taxes.

(b) Each of the Purchased Entities, other than Dome Petroleum LLC and 123456 Delaware LLC, is a taxable Canadian corporation (as defined in the Tax Act). No election has been filed under U.S. Treasury Reg. §301.7701-3(c) to classify Dome Petroleum LLC or 123456 Delaware LLC as an association for U.S. tax purposes.

(c) Each of the Purchased Entities, other than Dome Petroleum LLC and 123456 Delaware LLC, is duly registered under Subdivision (d) of Division V of Part IX of the *Excise* Tax Act (Canada) with respect to the goods and services tax and similar applicable provincial or territorial Tax legislation.

(d) Except as provided in Schedule 4.25(d), as at the date hereof, no material matter is under objection or appeal with any Governmental Authority relating to Taxes of any of the Purchased Entities.

(e) Vendor has disclosed to Purchaser all known contingent Tax liabilities that, as at the date hereof, would be reflected in the financial statements of any of the Purchased Entities prepared in accordance with IFRS and that could prompt a material assessment or reassessment of Taxes with respect to the Purchased Entities.

(f) The Purchased Entities have paid all material amounts to applicable Governmental Authorities required to be paid under the Canada Pension Plan and applicable employment insurance, employment pension plan and employee health insurance legislation in the relevant provinces and territories of Canada and any relevant foreign jurisdiction, and have withheld or collected and remitted in a timely manner to the applicable Governmental Authorities all material amounts of Taxes required to be withheld or collected and remitted by them. None of the Purchased Entities has

received any requirement from any Governmental Authority pursuant to section 224 of the Tax Act which remains unsatisfied in any respect.

(g) None of the Purchased Entities has, or will have, an obligation to file any Tax Return or to pay any Tax under the laws of any jurisdiction other than Canada or the United States as a result of Entity Assets owned or activities conducted on or before the Closing Date in Canada or the United States.

(h) Vendor is not a foreign person for purposes of Section 1445 of the Code.

4.26 Treaty-Protected Property

The Shares are Treaty-Protected Property in respect of which Vendor will provide a Treaty Exemption Certificate or Certificate of Proposed Disposition as contemplated in Schedule 3.2(d).

4.27 Commissions and Fees

Neither Vendor nor any of the Purchased Entities has incurred any liability or obligation, contingent or otherwise, for brokerage fees, finder's fees, agent's commissions or other similar forms of compensation with respect to the transactions contemplated hereby for which Purchaser or any of its Affiliates or the Purchased Entities may be liable.

4.28 [*****].

ARTICLE 5
REPRESENTATIONS AND WARRANTIES OF PURCHASER

Purchaser represents and warrants to Vendor that:

5.1 Incorporation

(a) Purchaser is a duly incorporated corporation and is as at the date hereof validly existing under the laws of the Province of Alberta and will as at the Closing Date validly exist under the laws of the Province of Nova Scotia.

(b) Purchaser Guarantor is a limited partnership duly organized and validly existing under the laws of the State of Delaware.

5.2 Due Authorization

(a) Purchaser has all necessary corporate power, authority and capacity to enter into this Agreement and to carry out its obligations under this Agreement.

(b) Purchaser Guarantor has all necessary power, authority and capacity to enter into the Purchaser Parent Guarantee and to carry out its obligations under the Purchaser Parent Guarantee.

[*****] indicates redacted terms for which confidential treatment has been requested from the SEC. The redacted information has been filed separately with the SEC.

(c) The execution and delivery of this Agreement and the performance of Purchaser’s obligations under this Agreement have been duly authorized by all necessary corporate action on the part of Purchaser.

(d) The execution and delivery of the Purchaser Parent Guarantee and the performance of Purchaser Guarantor’s obligations under the Purchaser Parent Guarantee have been duly authorized by all necessary partnership action on the part of Purchaser Guarantor.

(e) Subject to the receipt of all Required Approvals, neither the execution and delivery of this Agreement by Purchaser, nor the performance of Purchaser’s obligations under this Agreement will conflict with, or result in the violation or breach of, or render Purchaser in default of, or result in the termination or cancellation or in a right of termination or cancellation of, or accelerate the performance required by, or result in being declared void, voidable or without further binding effect, any of the terms, conditions or provisions of:

(i) the Constating Documents of Purchaser,

(ii) any material Contract to which Purchaser is a party or by which Purchaser is bound, or

(iii) any Applicable Laws, Environmental Laws or Governmental Authorizations applicable to Purchaser.

(f) Neither the execution and delivery of the Purchaser Parent Guarantee by Purchaser Guarantor, nor the performance of Purchaser Guarantor’s obligations under the Purchaser Parent Guarantee will conflict with, or result in the violation or breach of, or render Purchaser Guarantor in default of, or result in the termination or cancellation or in a right of termination or cancellation of, or accelerate the performance required by, or result in being declared void, voidable or without further binding effect, any of the terms, conditions or provisions of:

(i) the Constating Documents of Purchaser Guarantor,

(ii) any material Contract to which Purchaser Guarantor is a party or by which Purchaser Guarantor is bound, or

(iii) any Applicable Laws, Environmental Laws or Governmental Authorizations applicable to Purchaser Guarantor.

5.3 Enforceability of Obligations

(a) This Agreement constitutes a legal, valid and binding obligation of Purchaser, enforceable against Purchaser in accordance with its terms, subject to bankruptcy, winding-up, insolvency, moratorium, arrangement, reorganization and other similar laws affecting creditors’ rights generally and to general principles of equity.

(b) The Purchaser Parent Guarantee constitutes a legal, valid and binding obligation of Purchaser Guarantor, enforceable against Purchaser Guarantor in accordance with its

terms, subject to bankruptcy, winding-up, insolvency, moratorium, arrangement, reorganization and other similar laws affecting creditors’ rights generally and to general principles of equity.

5.4 Investment Canada Act

Purchaser is a non-Canadian within the meaning of the Investment Canada Act.

5.5 Governmental Authorizations

Except for the Required Approvals, no Governmental Authorizations are required on the part of Purchaser or Purchaser Guarantor in connection with the Purchase or on the part of Purchaser in connection with the performance of its obligations under this Agreement or on the part of Purchaser Guarantor in connection with the performance of its obligations under the Purchaser Parent Guarantee.

5.6 Commissions and Fees

Purchaser has not incurred any liability or obligation, contingent or otherwise, for any brokerage fees, finder’s fees, agent’s commissions or similar forms of compensation with respect to this Agreement or the transactions contemplated hereby for which Vendor or any of Vendor’s Affiliates may be liable.

5.7 Purchaser as Principal

Purchaser is an accredited investor as defined in National Instrument 45-106 — *Prospectus and Registration Exemptions* and is acquiring the Shares in its capacity as principal, and is not purchasing the Shares for the purpose of resale or distribution to a third party.

5.8 Sufficient Funds

Purchaser now has, and will at the Closing Time have, immediately available funds which, together with funds available to Purchaser pursuant to committed credit facilities, in respect of which complete and accurate copies of all publicly available agreements pertaining thereto have been made available to Vendor, are sufficient to pay all amounts payable by Purchaser hereunder. The Purchase by Purchaser is not contingent or dependent on any financing.

5.9 Purchaser Guarantor

Purchaser Guarantor has long term senior unsecured debt outstanding (being senior unsecured debt with a maturity of no less than one (1) year from the date on which such debt was incurred) rated not less than Investment Grade by two of S&P, Fitch and Moody’s, or an equivalent issuer rating. “**Investment Grade**” means at least “BBB-”, with respect to Standard & Poors and Fitch, and “Baa3”, with respect to Moody’s. “**S&P**” means Standard & Poor’s, a division of the McGraw-Hill Companies, Inc., “**Fitch**” means Fitch Ratings Ltd. and “**Moody’s**” means Moody’s Investors Service, Inc.

ARTICLE 6
REGARDING MATERIAL CLAIMS, REPRESENTATIONS, WARRANTIES AND COVENANTS

6.1 Material Claims

(a) For purposes of this Agreement, “**Material Claim**” means, in respect of any single incorrect or inaccurate representation or warranty made by Vendor in this Agreement or any single breach of any single covenant, that there has occurred or there could reasonably be expected to occur, as a result thereof, Losses to Purchaser or the Purchased Entities in excess of U.S.$1,000,000. For purposes of determining whether any single incorrect or inaccurate representation or warranty or any single breach of any single covenant is a Material Claim, Purchaser may aggregate individual Claims, Liabilities or Losses if such Claims, Liabilities or Losses arise out of the same incident, including any single incident, the Loss in respect of which continues over a period of time; provided that incidents of the same kind that occur at different times or at different locations, for purposes of this Section 6.1(a), may not be aggregated.

(b) Other than in respect of:

(i) the Vendor Fundamental Representations (and the indemnity in Section 10.1(a) related thereto),

(ii) the representations and warranties contained in Section 4.25 and Section 4.26 (and the indemnity in Section 10.1(a) related thereto),

(iii) the indemnities in Section 10.4(a), Section 10.4(c) and Section 10.5,

(iv) the indemnity and other provisions in Article 11,

(v) payments under Section 3.3(e) (as a result of adjustments to the Working Capital Statement) and payments under Section 3.4(e) (as a result of adjustments to the final Interim Period Cash Flow Statement), and

(vi) payment or reimbursement of out of pocket costs or expenses by Vendor to Purchaser contemplated in Sections 9.7, 9.13, 9.14, 10.7(b), 10.7(c), 10.7(d), 10.13(b), 11.7(b), 11.7(e) and 11.8(b).

Purchaser and the other Purchaser Indemnified Parties shall not be entitled to make any Claim (including under any indemnity of Vendor herein) against Vendor under this Agreement or in respect of the transactions contemplated hereby (whether now existing or hereafter arising and whether in contract, tort or equity, or under statute, or for breach of other duties or obligations) unless each such Claim is a Material Claim.

(c) For purposes of Section 6.1(a), including for purposes of:

(i) determining whether any breach of a representation or warranty of Vendor has occurred, and

(ii) calculating the amount of any Losses relating thereto, Vendor's representations and warranties shall be read and applied without regard to, and shall be deemed not to be qualified by, any reference in the text thereof to "materiality", "material", "materially", "material respects", "Material Adverse Effect" or similar materiality qualifiers set forth herein (other than the word "Material" in the expressions "Material Claim", "Material Consent", "Material Contract" or "Material Facility", as part of the defined term); provided, however, that the term "material respects" or the word "material", as applicable, shall continue to apply as a modifier with respect to the required content of the Schedules contemplated by Section 4.23(h) and Section 4.24(a).

6.2 Deductible in respect of Claims

(a) Other than in respect of:

(i) the Vendor Fundamental Representations (and the indemnity in Section 10.1(a) related thereto),

(ii) the representations and warranties contained in Section 4.25 and Section 4.26 (and the indemnity in Section 10.1(a) related thereto),

(iii) the indemnities in Section 10.4(a), Section 10.4(c) and Section 10.5,

(iv) the indemnity and other provisions in Article 11,

(v) payments under Section 3.3(e) (as a result of adjustments to the Working Capital Statement) and payments under Section 3.4(e) (as a result of adjustments to the final Interim Period Cash Flow Statement),

(vi) payment or reimbursement of out of pocket costs or expenses by Vendor to Purchaser contemplated in Sections 9.7, 9.13, 9.14, 10.7(b), 10.7(c), 10.7(d), 10.13(b), 11.7(b), 11.7(e) and 11.8(b), and

(vii) any payments required to be made by Vendor pursuant to Section 6.10(f).

Purchaser and the other Purchaser Indemnified Parties shall not be entitled to make any Claim under this Agreement or in respect of the transactions contemplated hereby (whether now existing or hereafter arising and whether in contract, tort or equity, or under statute, or for breach of other duties or obligations) unless the aggregate amount of all Material Claims as a result of all incorrect or inaccurate representations and warranties and all breaches of covenants of Vendor contained in this Agreement (including any Material Claims for indemnity arising out of those incorrect or inaccurate representations or warranties and those breaches of covenants) is equal to or greater than 2% of the Base Price, in which case Purchaser shall only be entitled (subject to Section 6.3) to recover the Losses related to those Material Claims in excess of 2% of the Base Price.

(b) For purposes of Section 6.2(a), including for purposes of:

(i) determining whether any breach of a representation or warranty of Vendor has occurred, and

(ii) calculating the amount of any Losses relating thereto,

Vendor's representations and warranties shall be read and applied without regard to, and shall be deemed not to be qualified by, any reference in the text thereof to "materiality", "material", "materially", "material respects", "Material Adverse Effect" or similar materiality qualifiers set forth herein (other than the word "Material" in the expressions "Material Claim", "Material Consent", "Material Contract" or "Material Facility", as part of the defined term); provided, however, that the term "material respects" or the word "material", as applicable, shall continue to apply as a modifier with respect to the required content of the Schedules contemplated by Section 4.23(h) and Section 4.24(a).

6.3 Limitation of Liability

Notwithstanding anything in this Agreement to the contrary, except in respect of:

(a) Claims under the indemnities contained in Section 10.1(a) for a breach of the representations and warranties set forth in Sections 4.25 and 4.26 only,

(b) Claims under the indemnities contained in Section 10.4(a), Section 10.4(c) and Section 10.5, and

(c) Claims under the indemnity and other provisions in Article 11, including in respect of Tax Claims,

none of which shall be subject to the following limitation on liability in this Section 6.3, the maximum cumulative Liability of Vendor in the aggregate in respect of:

(d) all Material Claims relating to incorrect or inaccurate representations and warranties that are Vendor Fundamental Representations (and the indemnities related thereto) shall be limited to an amount equal to the Purchase Price minus the amount of all Liabilities of Vendor referred to in Section 6.3(e), and

(e) all Material Claims relating to:

(i) incorrect or inaccurate representations and warranties in this Agreement (other than Vendor Fundamental Representations (and the indemnities related thereto)); and

(ii) breaches of covenants, including the covenant in Section 6.10 (and the indemnities related thereto);

shall be limited to U.S.$400,000,000.

6.4 Survival of Vendor's Representations, Warranties, Covenants and Indemnities and Limitations on Claims

(a) The representations and warranties of Vendor set forth in Sections 4.1, 4.2, 4.3, 4.4, 4.5, 4.6 and 4.28 (collectively, the "**Vendor Fundamental Representations**") shall survive the Closing indefinitely. The representations and warranties of Vendor set forth in Article 4, other than Vendor Fundamental Representations and subject to the proviso in this Section 6.4(a) in respect of Section 4.25 and Section 4.26, shall survive the Closing for the benefit of Purchaser for a period of eighteen (18) months from Closing (the "**Warranty Notice Period**"), after which time they shall terminate and, unless Purchaser shall have delivered to Vendor within the Warranty Notice Period a notice setting forth in reasonable detail the alleged inaccuracies in such representations and warranties and Purchaser's good faith estimate of the Losses arising therefrom, Purchaser shall no longer be entitled to rely upon those representations and warranties, and indemnities related thereto, in any manner whatsoever in the assertion of any Material Claim against Vendor hereunder or otherwise, provided that, in respect of the representations and warranties set forth in Sections 4.25 and 4.26 and the indemnities related thereto, the Warranty Notice Period shall be 120 days after the later of:

(i) the last date on which an assessment or reassessment for Taxes under the Tax Act or under any other Applicable Laws or Environmental Laws imposing Taxes can be made against the applicable Purchased Entity in respect of the dates or periods covered by those representations and warranties,

(ii) the date on which the period for an appeal from an assessment, reassessment or other determination of those Taxes has expired and that appeal has not been filed,

(iii) the date on which an agreement to settle an assessment, reassessment or other determination of those Taxes becomes binding, and

(iv) the date on which a judgment of a court of competent jurisdiction in respect of those Taxes becomes final and from which no right of appeal exists.

(b) The covenants of Vendor set forth in Sections 9.1, 9.2, 9.5, 9.6, 9.8, 9.9 and 9.16 and the indemnity in Section 10.4(b) shall survive the Closing for the benefit of Purchaser for a period of eighteen (18) months from Closing (the "**Covenant Notice Period**") after which time they shall terminate and, unless Purchaser shall have delivered to Vendor within the Covenant Notice Period a notice setting forth in reasonable detail the alleged breaches of such covenants by Vendor and Purchaser's good faith estimate of the Losses arising therefrom, Purchaser shall no longer be entitled to rely upon those covenants, and indemnities related thereto, in any manner whatsoever in the assertion of any Material Claim against Vendor hereunder or otherwise. The covenants of Vendor contained in this Agreement, other than those set forth in Sections 9.1, 9.2, 9.5, 9.6, 9.8, 9.9 and 9.16 and the indemnity in Section 10.4(b), shall survive the Closing and shall continue in full force and effect for the benefit of Purchaser in accordance with the terms thereof.

6.5 Survival of Purchaser's Representations, Warranties, Covenants and Indemnities

The representations and warranties of Purchaser set forth in Sections 5.1, 5.2 and 5.3 (collectively, the "**Purchaser Fundamental Representations**") shall survive the Closing indefinitely. The representations and warranties of Purchaser set forth in Article 5, other than Purchaser Fundamental Representations, shall survive the Closing for the benefit of Vendor for a period of eighteen (18) months from Closing (the "**Notice Period**"), after which time they shall terminate and, unless Vendor shall have delivered to Purchaser within the Notice Period a notice setting forth in reasonable detail the alleged breaches of or inaccuracies in such representations and warranties and Vendor's good faith estimate of the Losses arising therefrom, Vendor shall no longer be entitled to rely upon those representations and warranties, and indemnities related thereto, in any manner whatsoever in the assertion of any Claims against Purchaser hereunder or otherwise. The covenants of Purchaser contained in this Agreement shall survive the Closing and shall continue in full force and effect for the benefit of Vendor in accordance with the terms thereof.

6.6 No Consequential Damages

Neither Party will, in any circumstances whatsoever, be liable under this Agreement to the other Party or any of its Affiliates for indirect, incidental, consequential, exemplary or punitive damages suffered, sustained, paid, incurred or claimed by the other Party or the other Party's Related Parties. However, nothing in this Agreement shall in any way limit the right of any Indemnified Party to be indemnified pursuant to Article 10 for any and all indirect, incidental, consequential, exemplary or punitive damages of any nature or kind whatsoever that are part of any Third Party Claim.

6.7 No Other Representations, Warranties or Covenants of Vendor

Purchaser acknowledges to and agrees with Vendor as follows:

(a) Neither Vendor, nor any Purchased Entity, nor anyone acting on its or their behalf (including any of its or their Related Parties) has made or makes any representation, warranty, covenant or agreement, express or implied, to or with Purchaser except as expressly set forth in this Agreement and the Closing Documents delivered by Vendor, and this Agreement and such Closing Documents contain all the representations, warranties, covenants and agreements of Vendor relating to the Purchase, including with respect to the Shares, the Purchased Entities, the Entity Assets, the Previously Owned Assets and the Business.

(b) No oral or other statements or representations (whether express or implied) by any Person have induced or influenced Purchaser to enter into this Agreement or to agree to any of its terms, or have been relied on in any way by Purchaser as being accurate or have been taken into account by Purchaser as being important to Purchaser's decision to enter into this Agreement or agree to any of its terms.

(c) Except for those representations, warranties or covenants set forth herein or in any Closing Documents, without limiting the generality of Sections 6.7(a) or (b), no representation, warranty, covenant or agreement has been made by Vendor, any of the

Purchased Entities or anyone acting on its or their behalf (including any of its or their Related Parties) in or in relation to:

(i) any data or information provided or made available to Purchaser by Vendor's Investment Bankers, on plant or site visits, in management presentations, in meetings with management or employees or otherwise, including, any statement contained in the Information Memorandum, the KPMG Report, the Data Room or any other written material made available to Purchaser or its Related Parties,

(ii) any forecasts, projections or estimates (including any contained in the Information Memorandum, management presentations or any related break-out sessions) as to the future of the Business (including any revenue or profits which may be derived from the Business or the Entity Assets) provided by Vendor or any of the Purchased Entities or any of their Related Parties to Purchaser or any of Purchaser's Representatives,

(iii) any oral statement by any Person,

(iv) the value of the Business, the Shares, the Purchased Entities, the Entity Assets or the future cash flow from the Business, the Purchased Entities or the Entity Assets,

(v) the Environmental condition of any Entity Asset or Previously Owned Asset, any Environmental Matter, any Environmental Liability or any Abandonment and Reclamation Obligation,

(vi) any operations information or any economic evaluations,

(vii) title to the Entity Assets,

(viii) Liabilities, including Environmental Liabilities, Abandonment and Reclamation Obligations, Claims related to the Entity Assets or the Previously Owned Assets or any operations related to the Entity Assets or the Previously Owned Assets,

(ix) the past, present or future exercise of any regulatory, administrative or ministerial discretion under any Applicable Law, Environmental Law or Governmental Authorization,

(x) the past, present or future performance, operation, ownership or profitability of the NGLs industry in North America,

(xi) the existence of any present or future business opportunities of any of the Purchased Entities of any type whatsoever, including in respect of the NGLs industry in North America, or

(xii) the state or condition of the Entity Assets (which are acknowledged by Purchaser to be on an "as-is" basis), including the physical condition, the fitness for a particular purpose or the merchantability thereof, the existence or

absence of latent or patent defects therein, the quality thereof, the Environmental condition thereof, or any other aspect or characteristic thereof or relating thereto.

(d) Subject to the provisions of this Agreement, and except for the Confidential Contracts, Vendor has provided Purchaser with the opportunity to conduct all such enquiries, investigations and due diligence regarding the Shares, the Purchased Entities, the Entity Assets and the Business and all such other matters as Purchaser considered necessary or desirable in connection with the completion of the Purchase in accordance with this Agreement and Purchaser has entered into this Agreement as a result of its own due diligence, investigations, enquiries, advice and knowledge and the representations, warranties and covenants contained only in this Agreement. Except as otherwise expressly provided herein, Purchaser assumes full business and financial risk in connection with the Purchase, including in respect of the Entity Assets and the Business.

(e) Purchaser has knowledge and experience in the NGLs industry generally and is capable of evaluating the merits associated with entering into and performing its obligations under this Agreement.

(f) Except for its rights under this Agreement, any Contract to which Purchaser or any of its Affiliates is a party and the Closing Documents, Purchaser hereby waives all rights and remedies (whether now existing or hereafter arising and including all common law, tort, contractual, equitable and statutory rights and remedies) against Vendor, Vendor's Related Parties and the Purchased Entities in respect of the Shares, the Purchased Entities, the Entity Assets, the Previously Owned Assets and the Business, any and all representations or statements or information or data made or furnished to Purchaser or anyone acting on Purchaser's behalf, and any other matter pertaining to or otherwise relating to the transactions contemplated hereby (whether made or furnished by or on behalf of Vendor and whether made or furnished orally or by electronic, faxed, written or other means).

6.8 No Other Representation, Warranties or Covenants of Purchaser

Vendor acknowledges to and agrees with Purchaser that neither Purchaser nor anyone acting on its behalf (including any of its Related Parties) has made or makes any representation, warranty, covenant or agreement, express or implied, to or with Vendor except as expressly set forth in this Agreement and in the Closing Documents delivered by Purchaser, and this Agreement and such Closing Documents contain all the representations, warranties, covenants and agreements of Purchaser relating to the Purchase. No oral or other statements or representations (whether express or implied) by any Person have induced or influenced Vendor to enter into this Agreement or to agree to any of its terms, or have been relied on in any way by Vendor as being accurate or have been taken into account by Vendor as being important to Vendor's decision to enter into this Agreement or agree to any of its terms.

6.9 Restrictions on Claims

(a) Purchaser acknowledges to and agrees with Vendor that Vendor will not be liable for, and Purchaser will not make or advance, any Claim (other than a Tax Claim) under this

Agreement or in respect of the transactions contemplated hereby to the extent that the Claim is based on or arises from:

(i) any fact, matter, circumstance or event which is disclosed herein or in any Material Contract that is listed, described or referred to on Schedule 4.14(a),

(ii) any fact, matter, circumstance or event, which, as of the date hereof, to the actual knowledge of the individuals named in Clause (a) of Part 2 of Schedule 1.3, (i) constituted a breach of any of Vendor's representations or warranties, or (ii) was a material error in, or material omission from, the Schedules or other disclosure made in writing to Purchaser by Vendor for purposes of this Agreement, and which Purchaser failed to disclose to Vendor prior to the date hereof,

(iii) any fact, matter, circumstance or event for which and to the extent that an adequate provision therefor has been made in the Financial Statements or Working Capital Statement,

(iv) any fact, matter, circumstance or event which is, or is the basis for, a Permitted Encumbrance,

(v) any breach of this Agreement which would not have occurred but for the retrospective application of any change in Applicable Law or Environmental Law enacted subsequent to the date hereof, provided that the foregoing shall not relieve Vendor or any of the Purchased Entities from complying with Applicable Law or Environmental Law, or

(vi) any act, omission, transaction or arrangement or matter by, of or on behalf of, or in relation to Purchaser or any of the Purchased Entities on or after the Closing Date, or

(vii) anything done or not done with Purchaser's written consent (including by email) after the date hereof.

(b) Subject to Article 11 in respect of Taxes and Tax Claims, any and all Claims under this Agreement or otherwise in respect of the transactions contemplated hereby shall only be made, and any and all remedies related thereto shall only be available, under, in accordance with and subject to the provisions of Article 10 and Article 12.

(c) All disclosures in this Agreement (including in the Schedules to this Agreement), are to be taken as relating to each of Vendor's representations, warranties, covenants and agreements in this Agreement to the extent that the relationship is reasonably apparent, and to Vendor's indemnities provided in this Agreement.

6.10 Acknowledgement Regarding Scope of Entity Assets

(a) Vendor acknowledges to and agrees with Purchaser that the Entity Assets together with certain Excluded Assets comprise substantially all of the assets, tangibles, contracts, intangibles, properties, rights and interests used to generate the cash flows reflected in

the Financial Statements. If within eighteen (18) months of Closing, Purchaser notifies Vendor in writing that it believes one or more of the assets, tangibles, contracts, intangibles, properties, rights and interests used to generate any portion of the cash flows reflected in the Financial Statements was not owned by a Purchased Entity at Closing ("**Non-Transferred Entity Asset**"), the following provisions shall apply:

(i) if such Non-Transferred Entity Asset can be transferred or conveyed to the Corporation or applicable Purchased Entity with minimal cost or burden to Vendor, Vendor will cause such Non-Transferred Entity Asset to be so transferred or conveyed; and

(ii) if Section 6.10(a)(i) is not applicable and the Loss to Purchaser or the Purchased Entities of not owning or being in possession of such Non-Transferred Entity Asset at Closing is or is reasonably expected to be U.S.$1,000,000 or more,

Vendor will use all commercially reasonable efforts to execute and deliver, or to cause to be executed and delivered, to the Purchased Entities such instruments of conveyance and take such other actions as Purchaser may reasonably request to convey title to and ownership of, and to put Purchaser or the Purchased Entities in possession of, such Non-Transferred Entity Asset.

(b) If Vendor is unable, after all commercially reasonable efforts, to convey title to and ownership of, and to put Purchaser or the Purchased Entities in possession of, any Non-Transferred Entity Asset described in Section 6.10(a)(ii) above, then Vendor and Purchaser will attempt to agree on a reasonable amount of compensation due Purchaser, subject to the limitations in Article 6, as a result of the fact that the Non-Transferred Asset was not owned by a Purchased Entity at Closing, taking into account, without limitation, the loss of net benefit to the Purchased Entities. If the Parties are unable to agree on the foregoing matters of compensation, then the matter shall be referred to arbitration in accordance with Section 9.20. Any compensation paid to Purchaser pursuant to this Section shall be an adjustment to the Purchase Price.

(c) If Vendor is able to convey title to and ownership of, and to put Purchaser or the Purchased Entities in possession of, such Non-Transferred Entity Asset, then Vendor and Purchaser will attempt to agree on a reasonable amount of compensation due Purchaser, subject to the limitations in Article 6, as a result of the fact that the Non-Transferred Asset was not owned by a Purchased Entity at Closing, taking into account, without limitation, the loss of net benefit to the Purchased Entities. If the Parties are unable to agree on the foregoing matters of compensation, then the matter shall be referred to arbitration in accordance with Section 9.20. Any compensation payable as a result of this provision will be treated as a Purchase Price adjustment.

(d) Except as provided in Section 6.10(f) below, nothing in this Section 6.10 shall, however, have the effect of providing Purchaser with any additional right or remedy with respect to any defect in title to any Entity Asset consisting of real property interests described in Schedule 4.11 and Purchaser's rights with respect to any such defect in title shall be limited to such rights as Purchaser may have for breach of the representation and warranty of Vendor in Section 4.11.

(e) Purchaser acknowledges and agrees that the following shall not form part of the Entity Assets and shall not be subject to the covenant in Section 6.10(a): Commodity Sales & Marketing Services currently provided by Purchased Entities' Integrated Supply & Trading Division; All rail logistics & support services provided to the Business by any Affiliate of the Purchased Entities; All technical, engineering and other support services or arrangements provided to the Business by any Affiliate of the Purchased Entities relating to wells; All pipeline services or arrangements provided to the Business by any Affiliate of the Purchased Entities, including but not limited to regulatory compliance guidance, regulatory filings and aviation patrols; All engineering services arrangements provided to the Business by any Affiliate of the Purchased Entities, including but not limited to the technical expertise provided from time-to-time for project management, decision-making and technical standards support.

(f) With respect to the matters described on Schedule 6.10(f), Vendor shall: (a) use commercially reasonable efforts to cure or resolve such matters; and (b) with respect to any such matters that have been or are hereafter cured or resolved, provide evidence of such cure or resolution to Purchaser. The Purchaser will not do or omit to do anything that would have the effect of preventing or frustrating the Vendor from curing or resolving any matter described in Schedule 6.10(f). With respect to any such matters that Vendor is unable to cure or resolve by the first anniversary of the Closing Date or such other date as Vendor and Purchaser may agree upon with respect any of the matters described in Schedule 6.10(f) (herein referred to as an "Uncured Matter"), Vendor and Purchaser agree as follows:

(i) Vendor and Purchaser will attempt to agree on the amount of the Loss suffered since the Closing Date by Purchaser or the Purchased Entities attributable to such Uncured Matter, which Loss shall be determined taking into account all factors that are relevant to the financial losses and diminution in value suffered by the applicable Purchased Entity as a result of such Uncured Matter, including the extent, if any, to which such Uncured Matter (A) has or will negatively impact the cash flows from the facility to which the applicable property relates, (B) prevents the applicable Purchased Entity from using and enjoying the applicable real property in the same fashion that it has been used and enjoyed in connection with the normal operation of the Business prior to the date hereof, (C) constitutes a matter that would be viewed by a reasonable and prudent operator of a similar business in the applicable geographic area as a matter that impacts the value of the applicable property and (D) adversely impacts the resale value of the affected property;

(ii) If the amount of such Loss is U.S. $1,000,000 or more, such Uncured Matter shall be treated as a Material Claim hereunder and as a Material Claim described in Section 6.3(e)(ii) for the purpose of Section 6.3 (except that the limitation set forth in Section 6.2 shall not apply to any such Material Claims) and Vendor and Purchaser will attempt to agree on a reasonable amount of compensation due Purchaser as a result of such Uncured Matter and the Loss associated therewith;

(iii) If Vendor and Purchaser are unable to agree upon the amount of Loss of an Uncured Matter or the amount of compensation due Purchaser or the applicable Purchased Entity in connection therewith, the matter shall be referred to arbitration in accordance with Section 9.20;

(iv) Any amounts paid to Purchaser pursuant to this Section shall be treated as an adjustment to the Purchase Price; and

(v) This Section 6.10(f) shall be the sole and exclusive remedy of Purchaser with respect to the matters set forth in Schedule 6.10(f) and the Purchaser shall have no rights or remedies for breach of the representation and warranty in Section 4.11 with respect to the matters described in Schedule 6.10(f). Purchaser acknowledges that nothing in this Section shall obligate Vendor to cure any matters constituting Permitted Encumbrances.

ARTICLE 7
PURCHASER'S CONDITIONS

Subject to Section 12.2, the obligation of Purchaser to complete the Purchase in accordance with this Agreement shall be subject to the satisfaction of, or compliance with, at or before the Closing Time, each of the following conditions (collectively, the "**Purchaser's Conditions**") in this Article 7, each of which is acknowledged to be inserted for the exclusive benefit of Purchaser and may be waived by Purchaser in whole or in part.

7.1 Correctness and Accuracy of Representations and Warranties

Subject to Section 12.2,

(a) the Vendor Fundamental Representations shall be true and correct in all respects as at the Closing Time with the same effect as if made at and as of the Closing Time except to the extent any such representation and warranty is affected by actions or omissions consented to or waived by Purchaser or otherwise permitted or contemplated by this Agreement including the Permitted Pre-Closing Actions, and

(b) the representations and warranties of Vendor, other than the Vendor Fundamental Representations, shall be true and correct in all material respects as at the Closing Time with the same effect as if made at and as of the Closing Time (unless any such representation and warranty is expressly made as of the date hereof or as of a specific date, in which case such representation and warranty shall have been true and correct, in all material respects, as of the date hereof or such specific date only, as the case may be, and except to the extent any such representation and warranty is affected by actions or omissions consented to or waived by Purchaser or otherwise permitted or contemplated by this Agreement including the Permitted Pre-Closing Actions).

7.2 Performance of Obligations

Subject to Section 12.2, Vendor shall have performed or complied with, in all material respects, all its obligations, covenants and agreements under this Agreement required to be performed or complied with by Vendor at or before the Closing Time (except as to such obligations, covenants

and agreements qualified by materiality, in which case Vendor shall have performed or complied with such obligations, covenants and agreements in all respects), except for the obligation in Section 3.2(e), which must be fully performed without exception or qualification.

7.3 Required Approvals Obtained

The Required Approvals shall have been obtained and shall not have been revoked and, if applicable, the waiting period required by the HSR Act shall have expired or the applicable Governmental Authority of the United States shall have otherwise agreed to permit Closing to occur (the "**Regulatory Condition**").

7.4 Material Consents Obtained

All Material Consents shall have been obtained on terms and conditions that shall not reasonably be expected to result in a Material Adverse Effect.

7.5 No Legal Impediment to Closing

There shall not be in effect any Applicable Law or Environmental Law which enjoins, materially restricts, prohibits or makes illegal the Purchase provided the Regulatory Condition has been satisfied.

7.6 No Injunctions or Restraints

No restraining order, injunction or other order or decree issued by any Governmental Authority of competent jurisdiction enjoining, restraining or otherwise preventing the completion of the Purchase in accordance with this Agreement shall be in effect, provided however, that Purchaser shall use commercially reasonable efforts to prevent the entry of any such restraining order, injunction or other order or decree and to cause any such restraining order, injunction or other order or decree that may be entered to be vacated or otherwise rendered of no effect, provided however, neither Purchaser nor its Affiliates shall be required to sell, divest, dispose of, or hold separate any material portion of its or their business or assets.

7.7 Completion of the Reorganization

Before the Closing Date, the Reorganization, including all steps and transactions contemplated thereby (other than any filing or other matter that would routinely be completed after closing of the Reorganization), shall have been completed substantially in accordance with its terms.

7.8 IT Related Matters

All matters contemplated by Schedule 9.17 to be completed on or prior to Closing shall have been completed in all material respects (the "**IT Condition**").

7.9 Vendor's Closing Deliveries

Subject to Section 2.1(b), at or before the Closing Time, Vendor shall have delivered to Purchaser the following, in form and substance satisfactory to Purchaser, acting reasonably:

(a) one or more share certificates representing the Shares, duly endorsed in blank for transfer, or accompanied by irrevocable stock transfer powers of attorney duly executed in blank by the holder of record, together with evidence satisfactory to Purchaser (acting reasonably) that Purchaser or its nominee(s) has been entered on the books of the Corporation as the registered holder of the Shares (collectively, the "**Share Documents**"),

(b) certified copies of:

(i) the Constating Documents of Vendor, each of the Purchased Entities and Vendor Guarantor,

(ii) all resolutions of the board of directors of Vendor approving the entering into of this Agreement and the completion of the Purchase, resolutions of the Vendor Guarantor approving the entering into of the Vendor Parent Guarantee and resolutions of the board of directors of the Corporation approving the transfer of the Shares, and

(iii) an incumbency certificate of Vendor and Vendor Guarantor in respect of the individuals executing this Agreement on behalf of Vendor and the Vendor Parent Guarantee on behalf of Vendor Guarantor and any Closing Documents delivered by Vendor or Vendor Guarantor, together with their specimen signatures,

(c) certificates of status issued by the appropriate Governmental Authority with respect to Vendor and each of the Purchased Entities which are corporations and in respect of which certificates of status are obtainable from the applicable Governmental Authority in the jurisdiction in which Vendor or such Purchased Entity is incorporated,

(d) a certificate from a Senior Officer of Vendor confirming the matters set forth in Sections 7.1(a) and (b) and Section 7.2, subject to Section 12.2, except to the extent otherwise described in such certificate, which certificate shall be given by such Senior Officer in his capacity as a Senior Officer of Vendor and not in his personal capacity and without personal liability on the part of such Senior Officer,

(e) a duly executed release and resignation, effective as of the Closing Time, of each director and officer of the Purchased Entities,

(f) a receipt for payment of the Closing Consideration,

(g) copies of the Required Approvals obtained by Vendor,

(h) a copy of the Litigation Support Agreement duly executed by Vendor,

(i) a copy of the Transition Services Agreement duly executed by Vendor,

(j) a DVD containing the contents of the virtual Data Room as at the date hereof,

(k) a list of any bank accounts or bank arrangements relating to or used in connection with the Business not closed or assigned to Vendor's Affiliates other than the Purchased Entities at or prior to Closing and such documents as Purchaser shall reasonably request to evidence that the directors, officers and other signing authorities in respect of such bank accounts have relinquished control over any such bank accounts, together with such reasonable supporting documentation as may be required by the banks or other financial institutions with which such bank accounts are maintained as are requested by Purchaser, and

(l) any other documents reasonably required to be delivered by Vendor to Purchaser at the Closing Time pursuant to this Agreement.

7.10 Payment of Interim Cash Flow Amount

The Vendor shall have caused to be paid to the Corporation the Interim Cash Flow Amount, if a positive amount, contemplated by Section 3.2(e).

7.11 No Damage or Destruction Event

Subject to Section 12.2, there shall have been no Damage or Destruction Event in relation to the Entity Assets.

ARTICLE 8
VENDOR'S CONDITIONS

The obligation of Vendor to complete the Purchase in accordance with this Agreement shall be subject to the satisfaction of, or compliance with, at or before the Closing Time, each of the following conditions (collectively, the "**Vendor's Conditions**") in this Article 8, each of which is acknowledged to be inserted for the exclusive benefit of Vendor and may be waived by Vendor in whole or in part.

8.1 Correctness and Accuracy of Representations and Warranties

The representations and warranties of Purchaser contained in Article 5 shall be correct and accurate in all material respects (except as to such representations and warranties qualified by materiality, in which case such representations and warranties shall be correct and accurate in all respects) as at the Closing Time with the same effect as if made at and as of the Closing Time (unless any such representation and warranty is made as of a date other than the date hereof, in which case such representation and warranty shall be correct and accurate in all material respects or correct and accurate in all respects, as the case may be, as of such other date and except to the extent any such representation and warranty is affected by actions or omissions consented to or waived by Vendor or permitted or contemplated by this Agreement).

8.2 Performance of Obligations

Purchaser shall have performed or complied with, in all material respects, all its obligations, covenants and agreements under this Agreement required to be performed or complied with by Purchaser prior to or at the Closing Time in all material respects (except as to such obligations, covenants and agreements qualified by materiality, in which case Purchaser shall have performed or complied with such obligations, covenants and agreements in all respects).

8.3 Required Approvals Obtained

The Regulatory Condition shall have been satisfied.

8.4 Material Consents Obtained

All Material Consents shall have been obtained on terms and conditions that shall not reasonably be expected to result in a Material Adverse Effect.

8.5 No Legal Impediment to Closing

There shall not be in effect any Applicable Law or Environmental Law which enjoins, materially restricts, prohibits or makes illegal the Purchase provided the Regulatory Condition has been satisfied.

8.6 No Injunctions or Restraints

No restraining order, injunction or other order or decree issued by any Governmental Authority of competent jurisdiction enjoining, restraining or otherwise preventing the completion of the Purchase in accordance with this Agreement shall be in effect, provided however, that Vendor shall use commercially reasonable efforts to prevent the entry of any such restraining order, injunction or other order or decree and to cause any such restraining order, injunction or other order or decree that may be entered to be vacated or otherwise rendered of no effect, provided however, neither Vendor nor its Affiliates shall be required to sell, divest, dispose of, or hold separate any material portion of its or their business or assets.

8.7 Completion of the Reorganization

All steps and transactions necessary to give effect to the Reorganization prior to the Closing Date (other than any filing or other matter that would routinely be completed after closing of the Reorganization) that are dependent on the actions of Persons other than the Vendor and its Affiliates, shall have been completed so as to permit the Reorganization to be completed substantially in accordance with its terms.

8.8 IT Related Matters

The IT Condition shall have been satisfied.

8.9 Purchaser's Closing Deliveries

Subject to Section 2.1(b), at or before the Closing Time, Purchaser shall have delivered to Vendor the following, in form and substance satisfactory to Vendor, acting reasonably:

(a) the Closing Consideration by wire transfer in accordance with Section 2.3 and the wire transfer instructions contemplated by Section 3.2(d),

(b) a receipt acknowledging the delivery of the certificate for the Shares,

(c) certified copies of:

(i) the Constating Documents of Purchaser and Purchaser Guarantor,

(ii) all resolutions of the board of directors of Purchaser approving the entering into of this Agreement and the completion of the Purchase contemplated by this Agreement and resolutions of the Purchaser Guarantor approving the entering into of the Purchaser Parent Guarantee, and

(iii) incumbency certificates of Purchaser and Purchaser Guarantor in respect of the individuals executing this Agreement on behalf of Purchaser and the Purchaser Parent Guarantee on behalf of Purchaser Guarantor and any Closing Documents delivered by Purchaser or Purchaser Guarantor, together with their specimen signatures,

(d) certificates of status with respect to Purchaser and Purchaser Guarantor issued by the appropriate Governmental Authority,

(e) a certificate from a Senior Officer of Purchaser confirming the matters set forth in Sections 8.1 and 8.2, except to the extent otherwise described in such certificate, which certificate shall be given by such Senior Officer in his capacity as a Senior Officer of Purchaser and not in his personal capacity and without personal liability on the part of such Senior Officer,

(f) releases of each of the directors and officers of each of the Purchased Entities from any liability to any of the Purchased Entities and Purchaser,

(g) copies of the Required Approvals obtained by Purchaser,

(h) a copy of the Litigation Support Agreement duly executed by Purchaser,

(i) a copy of the Transitions Services Agreement duly executed by Purchaser, and

(j) any other documents reasonably required to be delivered by Purchaser to Vendor at the Closing Time pursuant to this Agreement.

ARTICLE 9
OTHER COVENANTS

9.1 Conduct of Business Prior to Closing

Except for Permitted Pre-Closing Actions and except as otherwise contemplated or permitted by this Agreement, Vendor shall, from the date of this Agreement until the Closing Time, cause the Purchased Entities to do the following:

(a) conduct the Business in the Ordinary Course of Business,

(b) except as to any continuing non-compliance referred to in Schedule 4.21(a) and provided the Vendor causes the Purchased Entities to use reasonable efforts to remedy such non-compliance, comply in all material respects with all Applicable Laws and Environmental Laws applicable to the Business, and

(c) comply in all material respects with all Material Contracts and notify Purchaser upon the entering into of any new Material Contracts.

9.2 Negative Covenants

Except for:

(a) Permitted Pre-Closing Actions,

(b) any act or omission to act undertaken in the Ordinary Course of Business,

(c) any act or omission to act undertaken pursuant to and in accordance with Material Contracts or any other Contract pertaining to the Business,

(d) anything contemplated or permitted by this Agreement,

(e) any act or omission to act undertaken in an emergency in order to prevent loss of life, injury to persons or damage to or loss of property,

(f) any act or omission to act undertaken with the written consent of Purchaser, and

(g) anything required to be done or not done by Applicable Law, Environmental Law or Governmental Authorizations,

(h) any cash transfers from a Purchased Entity to Vendor or any Affiliate of Vendor, and

(i) anything done or not done in relation to the Excluded Assets or the Non-NGL Business,

any and all of which shall be permitted notwithstanding Sections 9.2(j) to (u) below, Vendor shall not permit any of the Purchased Entities to do, or agree to do, any of the following from the date of this Agreement until the Closing Time:

(j) carry on the Business otherwise than in the Ordinary Course of Business or in a manner that will result in a violation of any Applicable Laws or Environmental Laws;

(k) amend, in any material respect, the Constating Documents or bylaws of the Purchased Entities,

(l) except exclusively as among or between the Purchased Entities:

(i) issue any shares or other securities in the capital thereof,

(ii) issue any securities convertible, exchangeable or exercisable into, or issue or grant any rights, options or warrants to purchase or otherwise acquire, any unissued shares or other securities in the capital thereof,

(iii) sell or otherwise dispose of any shares or other ownership interests it may hold in the capital of any other Purchased Entity,

(iv) issue any securities convertible, exchangeable or exercisable into, or issue or grant any rights, options or warrants to purchase or otherwise acquire, any shares or other ownership interests it may hold in the capital of any other Purchased Entity, or

(v) merge, amalgamate or consolidate with or into any other Person,

(m) except as among or between the Purchased Entities, dispose of any of the Entity Assets having a fair market value, individually, in excess of $1,000,000,

(n) except as among or between the Purchased Entities, acquire any assets which, when acquired become Entity Assets, having a fair market value, individually, in excess of $1,000,000 or have the Purchased Entities incur or assume, or agree to have the Purchased Entities to incur or assume, any liabilities, other than in the Ordinary Course of Business,

(o) create or permit the creation of any new Encumbrance on the Entity Assets other than Permitted Encumbrances,

(p) except as required under a mail ballot or similar procedure under any Contract, make any single capital expenditure in relation to the Business in excess of $1,000,000, provided that, in the event Vendor seeks Purchaser's consent to any capital expenditure, in seeking Purchaser's consent, Vendor shall be entitled to seek consent for related groups of expenditures and submit investment memos or other documentation supporting the business case for such expenditures and Purchaser shall respond to Vendor's request within five (5) Business Days or be deemed to have granted its consent, and also provided that, if Purchaser withholds its consent for an expenditure and Vendor deems that the expenditure is necessary to maintain the safety and integrity of the Entity Assets, then the Purchased Entities may, acting reasonably, make such necessary expenditure and the making of such expenditure shall not be a breach of this Section 9.2(p),

(q) amend in any material respect or terminate before the end of the term thereof any Material Contract or any Title and Operating Document,

(r) enter into any Contract relating to the Business:

(i) with an Affiliate of Vendor (other than another Purchased Entity) unless the terms thereof are at least as favourable to the Purchased Entity as those terms that would generally be available from unrelated third parties, or

(ii) with a term in excess of one (1) year,

(s) quitclaim, decommission, abandon or allow to expire any of the Entity Assets except:

(i) Entity Assets which have become obsolete, or

(ii) where the rights of any of the Purchased Entities to those Entity Assets have expired or terminated,

(t) take any action which would result in the resignation or replacement of any Purchased Entity as operator of any of the Entity Assets, or

(u) settle any Claims or litigation other than any Claims or litigation for or in respect of which Vendor has the obligation to indemnify Purchaser hereunder.

If any of the Purchased Entities makes expenditures or takes actions necessary to prevent loss of life or injury to individuals, damage to or loss of property, Vendor shall give notice to Purchaser of those expenditures or actions and Vendor's estimate of the amounts expended or to be expended in connection therewith as soon as reasonably possible in the circumstances.

9.3 Credit Support Obligations

(a) Vendor shall be entitled to arrange for the release of any and all letters of credit, guarantees, credit support or other financial assurance ("**Credit Support**") outstanding at the Closing Time provided by Vendor or any of its Affiliates (other than the Purchased Entities) to any Person ("**Credit Support Counterparty**") for the benefit of any of the Purchased Entities ("**Existing Credit Support Obligations**").

(b) To facilitate Vendor's arrangement for the release of any Existing Credit Support Obligations, at Vendor's request, Purchaser shall, at or prior to the Closing Time, use commercially reasonably efforts to furnish such Credit Support as may be required by the Credit Support Counterparties as a condition for the release of Vendor or any of its Affiliates (other than the Purchased Entities) from the Existing Credit Support Obligations provided in connection with or relating to the Business.

(c) Notwithstanding Section 9.3(a) or (b), if any Credit Support Counterparty refuses, for any reason, to release Vendor or any of its Affiliates (other than the Purchased Entities) from any Existing Credit Support Obligation provided in connection with or relating to the Business, Purchaser shall be liable for and indemnify and hold Vendor and its Affiliates harmless from and against any and all Loss or Liability incurred by Vendor or its Affiliates (other than the Purchased Entities) arising under or in respect of such Existing Credit Support Obligations provided in connection with or relating to the Business.

(d) Not later than (30) Business Days after the date hereof, Vendor shall provide Purchaser with a list of all Existing Credit Support Obligations in connection with or relating to the Business.

9.4 Bank Accounts

(a) Vendor shall be entitled to cause the Purchased Entities to close or assign to any of Vendor's Affiliates, at any time at or prior to Closing, any and all bank accounts and other banking arrangements of or made by any of the Purchased Entities.

(b) With respect to any bank accounts or banking arrangements relating to or used in connection with the Business not so closed or assigned at or prior to Closing, Vendor shall provide Purchaser at Closing with a list of such accounts and arrangements and such documents as Purchaser may reasonably request at least five (5) Business Days prior to the Closing Date so as to evidence the fact that any individual having signing

authority in respect of such accounts prior to Closing shall not have such signing authority after Closing.

9.5 Access to Material Facilities

(a) Vendor shall cause the Purchased Entities to permit Purchaser and its Representatives, between the date of this Agreement and the Closing Time, on reasonable notice to the Senior Officers of the Corporation, to have reasonable access during normal business hours to the Material Facilities to the extent the Purchased Entities are permitted to grant access thereto and to senior personnel employed in connection with the operation of such facilities provided that:

(i) such access shall not unreasonably interfere with the operation of the Business in the Ordinary Course of Business,

(ii) such access shall be supervised by personnel of the Purchased Entities,

(iii) such access shall be in accordance with the rules, regulations and policies of the Purchased Entities,

(iv) such access shall be subject to the terms of the Confidentiality Agreements and subject to any releases or other agreements required by the operator of any of the Material Facilities,

(v) Purchaser and its Representatives shall not operate equipment, conduct testing, sample materials, perform Phase II environmental audits or conduct any invasive activities during such access,

(vi) Purchaser shall be responsible for arranging, at its own cost, transportation to and from the Material Facilities, and

(vii) such access shall be at the sole risk and expense of Purchaser and its Representatives.

Purchaser hereby releases Vendor Indemnified Parties from, and shall be liable for and indemnify, defend and hold harmless Vendor Indemnified Parties from and against, any and all Liability, Losses and Claims arising out of or connected with such access by Purchaser and its Representatives to the Material Facilities or employees or travel to or from, or presence on, the Material Facilities in connection with the transactions contemplated by this Agreement.

(b) Notwithstanding Section 9.5(a), Vendor shall not be required to cause any of the Purchased Entities to provide access to any Material Facilities or employees:

(i) where doing so is prohibited by any Applicable Law (including the Competition Act), Environmental Law or Governmental Authorizations,

(ii) where doing so would present a safety concern in the reasonable opinion of personnel of Vendor or of any of the Purchased Entities, or

(iii) where doing so would cause Vendor or any of its Affiliates, including the Purchased Entities, to be in violation of any confidentiality or other obligation to another Person provided that Vendor shall use commercially reasonable efforts to obtain the consent of any such Person that may be required in relation to the grant of access to the Material Facilities or employees.

9.6 Actions to Satisfy Closing Conditions

Without derogating from any Party’s rights or obligations under this Agreement, it is agreed that Vendor shall act in good faith and use all commercially reasonable efforts to satisfy, or cause to be satisfied, all of the Conditions set forth in Article 7, and Purchaser shall act in good faith and use all commercially reasonable efforts to satisfy, or cause to be satisfied, all of the Conditions set forth in Article 8. Each of Purchaser and Vendor shall act in good faith in determining whether or not a Condition in its favour has been satisfied.

9.7 Preservation of Records

Purchaser shall take all reasonable steps to preserve and keep the Books and Records until the later of:

(a) the seventh (7th) anniversary of the date of this Agreement,

(b) the date on which all Claims for which Vendor has any liability hereunder have been finally settled, and

(c) the date after which such Books and Records are no longer required to be preserved or kept under any Applicable Law, Environmental Law or Governmental Authority or pursuant to Section 11.8,

Purchaser shall make those Books and Records available to Vendor and its Representatives (and allow Vendor and its Representatives to make copies thereof at Vendor’s expense) as may be reasonably required by Vendor and its Representatives in connection with a Claim by Purchaser or any other Person against Vendor or any of its Affiliates under or relating to this Agreement, the Purchase or the other transactions contemplated hereby.

9.8 Filings for Required Approvals

Without limiting the provisions of Section 9.6:

(a) Purchaser shall be primarily responsible for the carriage of applications for the Required Approvals,

(b) Purchaser and Vendor shall, and shall use all commercially reasonable efforts to cause their respective directors, officers, employees and Representatives to:

(i) within fourteen (14) Business Days after the date of this Agreement make the filings required of Purchaser, Vendor, any of the Purchased Entities or any of their Affiliates to obtain the Required Approvals,

(ii) comply at the earliest practicable date with any request for additional information or documentary material received by Purchaser, Vendor, any of the Purchased Entities or any of their Affiliates from the applicable Governmental Authority, and

(iii) consult and cooperate in connection with any investigation, review or other inquiry in each case concerning the Purchase commenced by any Governmental Authority,

(c) each Party shall:

(i) promptly give notice to the other Party of any material communication received by that Party or its Affiliates from any Governmental Authority regarding the Purchase,

(ii) promptly, upon request, furnish to the other Party such information and assistance as the other Party may reasonably request in connection with its preparation of any filing or submission which is necessary to receive any Required Approval,

(iii) keep the other Party reasonably informed as to the status of the proceedings related to obtaining the Required Approvals, including providing the other Party with copies of all related applications and notifications,

(iv) where necessary and appropriate in the circumstances, furnish the other Party in advance with a copy of any material correspondence, filings and communication between it and its Affiliates and their respective Representatives, on the one hand, and the applicable Governmental Authority, on the other hand, with respect to this Agreement and the Purchase, and provide the other Party a reasonable opportunity to comment thereon and consider those comments in good faith, and

(v) not participate in any substantive meeting or discussion with any Governmental Authority in respect of any filings, investigation or inquiry concerning the Purchase, whether oral or in person, unless it consults with the other Party in advance and, to the extent permitted by the applicable Governmental Authority, gives the other Party the opportunity to attend and participate at any such meeting or discussion and if that participation is either declined or not permitted, to furnish promptly thereafter a memorandum setting forth the material terms of that meeting or those discussions,

(d) Purchaser shall be responsible for any filing fee, along with any applicable Taxes, to a Governmental Authority required in relation to obtaining a Required Approval,

(e) Purchaser shall advise Vendor promptly in advance of any understandings, undertakings or agreements which Purchaser proposes to make or enter into with any Governmental Authority (other than in relation to the Investment Canada Act Approval or with the Commissioner) in connection with the Purchase,

(f) without limiting the foregoing provisions of this Section 9.8, Purchaser agrees to use commercially reasonable efforts to obtain the Required Approvals as soon as practicable,

(g) notwithstanding the foregoing provisions of this Section 9.8:

(i) competitively sensitive information of a Party will be provided on a privileged and confidential basis only to the external legal counsel or external expert of the other Party and shall not be shared by such counsel or expert with any other Person, and

(ii) the plans of Purchaser as set forth in the application for review and other information filed with Industry Canada in connection with securing the Investment Canada Act Approval, including draft and final undertakings, and communications concerning the substance of the plans and undertakings will not be provided to Vendor or Vendor's Counsel, provided however that if the Minister designated pursuant to the Investment Canada Act either (A) sends a notice to Purchaser pursuant to subsection 23(1) of the said Act that he is not satisfied that the Purchase is likely to be of net benefit to Canada or (B) sends a Notice to Purchaser pursuant to subsection 22 (1) of the said Act extending the 45 day waiting period and has not within the time period ending 15 days prior to the expiry of the extended waiting period issued the Investment Canada Act Approval, Purchaser will promptly disclose that it has received the said notice pursuant to subsection 23 (1) or has not received the Investment Canada Act Approval, as the case may be, and Purchaser's Counsel shall provide to Vendor's Counsel, on a privileged and confidential "external counsel only" basis:

(A) the last draft of Purchaser's undertakings proposed to the Investment Review Division in connection with obtaining the Investment Canada Act Approval, and

(B) a synopsis of relevant communications on Behalf of Purchaser and the Investment Review Division relating to the said proposed undertakings.

(iii) proposed consent agreements, undertakings or remedies the Purchaser proposes to the Commissioner in order to obtain the Competition Act Approval including draft and final forms, and communications concerning the substance thereof will not be provided to Vendor or Vendor's Counsel provided however if the Competition Act Approval has not been issued by the Commissioner within a time period ending at the earlier of:

(A) 45 days after the date of the commencement of the service standard designated for the Purchase by the Commissioner in accordance with the Fee and Service Standards Handbook for Mergers and Merger-Related Matters, and

(B) the date on which the Commissioner advises of her preliminary conclusions with respect to the Purchase,

then Purchaser will promptly disclose that a Competition Act Approval has not been received and Purchaser's Counsel shall Provide to Vendor's Counsel, on a privileged and confidential "external counsel only" basis:

(C) the last draft of Purchaser's consent agreements, undertakings or remedies proposed, if any, to the Commissioner in connection with obtaining the Competition Act Approval; and

(D) a synopsis of relevant communications on behalf of Purchaser and the Commissioner relating to the said proposed consent agreements, undertakings or remedies.

9.9 HSR Filings

If a filing is required pursuant to the HSR Act in connection with the transactions contemplated by this Agreement, as promptly as practicable and in any event not more than fourteen (14) Business Days after the date of this Agreement, both Parties shall file with the U.S. Federal Trade Commission and the U.S. Department of Justice, as applicable, the required notification and report forms and shall as promptly as practicable furnish any supplemental information that may be requested in connection therewith. Purchaser shall direct, but the Parties shall cooperate with each other concerning, all proceedings in connection with obtaining the termination of the HSR waiting period, if applicable. Each Party shall bear its own costs associated with compliance with the HSR Act. Purchaser will bear any filing fees in connection with any filings required pursuant to the HSR Act for the purposes of this Section 9.9,

Notwithstanding the foregoing provisions of this Section 9.9 and the obligations of Vendor and Purchaser in Section 9.6, neither Purchaser, Vendor nor any of their respective Affiliates shall be required to sell, divest, dispose of, or hold separate any material portion of its or their business or assets or enter into or terminate any material contract or agreement, or otherwise make a material modification to their respective business conduct to satisfy their obligations to act in good faith and take commercially reasonable efforts to have the waiting period expire under the HSR Act.

9.10 Employee Related Matters

Each of the Parties agrees to the terms and conditions set forth in Schedule 9.10.

9.11 Insurance

Purchaser acknowledges that the insurance set forth in Schedule 9.11 is maintained or provided by the Purchased Entities ("**Vendor's Insurance**") and that, from and after Closing, in respect of events occurring after Closing, the Purchased Entities may no longer have the benefit of Vendor's Insurance. Purchaser acknowledges that certain Entity Assets, pursuant to agreements applicable to such assets, are required to be insured in accordance with such agreements. Vendor shall use all reasonable commercial efforts to maintain such Vendor's Insurance until Closing.

9.12 Purchase Not Conditional on Financing

Nothing in this Agreement shall make Purchaser's obligation to complete the Purchase, including Purchaser's obligation to make the payments referred to in Sections 2.1, 3.2 or 3.3 on a timely basis, conditional on Purchaser being able to obtain or complete any financing for the Purchase.

9.13 Reorganization

Purchaser acknowledges that the Reorganization will be concluded a short time prior to the Closing Date and that specific conveyances, notices of assignment, assignment and novation agreements, notices to and filings with Governmental Authorities and other documents required for, or of advantage to, Vendor and its Affiliates in connection with the Reorganization ("**post-Closing documents**") will be prepared and circulated by Vendor or the applicable Affiliate of Vendor for execution by the Purchased Entities or their successors who are Affiliates of a Purchased Entity and, as necessary, filed after Closing. Purchaser will, upon the request of Vendor or its Affiliates, and at Vendor's sole expense, after Purchaser has been afforded a reasonable opportunity to review such post-Closing documents, grant a limited power of attorney to an individual designated by Vendor who will execute such post-Closing documents on behalf of the Purchased Entities or their successors who are Affiliates of a Purchased Entity and Purchaser will permit Vendor and its Affiliates to file or deliver such documents in the name of the Purchased Entities or their successors who are Affiliates of a Purchased Entity as required to consummate the Reorganization.

9.14 Return of Excluded Assets

Purchaser acknowledges that it is the intention of the Parties that all Excluded Assets owned or held by the Purchased Entities shall be conveyed or otherwise transferred by the Purchased Entities to Vendor or one or more of Vendor's Affiliates (other than the Purchased Entities) prior to Closing. Purchaser shall cause each of the Purchased Entities and its and their Affiliates to fully cooperate with Vendor after Closing to effect such intention, including promptly executing and delivering to Vendor any and all conveyances or transfers or other documents required by Vendor or any of its Affiliates in connection therewith. Purchaser hereby, on its own behalf and on behalf of each of the Purchased Entities, grants to Vendor and Vendor's Affiliates an irrevocable power of attorney to prepare, execute, deliver and file any such conveyances, transfers and other documents as are or may be required or advisable in accordance with industry practice to give effect to the foregoing.

In the event that Purchaser or any of its Affiliates becomes aware of the fact (in respect of which Purchaser shall forthwith advise Vendor), or is advised by Vendor or any of its Affiliates in writing, that any Excluded Assets remain in the possession of any of the Purchased Entities or any of their Affiliates after Closing, Purchaser shall cause the Purchased Entities or their Affiliates, as the case may be, to forthwith put any and all such

Excluded Assets into the possession of Vendor or an Affiliate of Vendor designated by Vendor, and Vendor shall fully reimburse Purchaser or its applicable Affiliate for all actual out of pocket costs, including Taxes payable, incurred in doing so.

Purchaser shall and shall cause its Affiliates (including the Purchased Entities) to forthwith return, or at Vendor's request, destroy in a secure manner, any and all documents, data and

records in its or their possession reflecting or comprising Excluded Assets, including Excluded Books and Records (together with all copies thereof), and, in the event of a request for such destruction, promptly provide Vendor with a certificate of a Senior Officer of Purchaser confirming such destruction.

9.15 Delivery of Books and Records

Except as otherwise provided in Schedule 9.17, Vendor shall deliver to Purchaser:

(a) as soon as reasonably practicable, but no later than the earlier of the 90th day following the date hereof and the 15th Business Day prior to Closing:

(i) upon the reasonable request of Purchaser, copies of Canadian Tax Returns for the Canadian Purchased Entities pertaining to the Business for the fiscal year of 2010 and copies of the U.S. Tax Records for the Purchased Entities incorporated or formed in the United States (the "**U.S. Purchased Entities**") pertaining to the Business for the fiscal year of 2010;

(ii) subject to Section 9.19 and Vendor's policies, and the communication to the Entity Employees listed in Appendix A to Schedule 9.10 Part A of their terms and conditions commensurate with Schedule 9.10 Part A, such payroll information for Entity Employees listed in Appendix A to Schedule 9.10 Part A as Purchaser reasonably requires;

(iii) copies of active land records for any surface right or storage leases requiring payment within six months of Closing; and

(iv) all Material Contracts (other than Confidential Contracts and confidential Material Contracts executed after the date hereof) that have not been provided to Purchaser prior to the date hereof and any Material Contract entered into on or after the date hereof.

(b) within 15 days following Closing, Vendor shall deliver to Purchaser, in respect of each of the Purchased Entities, financial accounting records including general ledger detail support for the month end immediately preceding Closing and balance sheet account reconciliations for all balance sheet account balances for the month immediately preceding the month in which the Closing occurs, provided Purchaser has provided Vendor and its Affiliates with such access to books and records and cooperation of personnel of the Purchased Entities as Vendor may reasonably request to do so,

(c) within 10 Business Days after a Tax Return is filed for a Purchased Entity, copies of Canadian Tax Returns for a Canadian Purchased Entity in respect of that Tax Return and copies of U.S. Tax Records for a U.S. Purchased Entity in respect of that Tax Return relating to any period after 2010,

(d) within 90 days following Closing, the Books and Records (other than those books and records described in Sections 9.15(a) and 9.15(b)), and

(e) within 10 Business Days of a request by Purchaser, copies of all Tax Records of the Purchased Entities prior to Closing that Purchaser reasonably requests in connection with any dispute relating to such periods, or for the purpose of preparing audited financial statements in accordance with U.S. GAAP.

Vendor shall be entitled to retain copies of any of the Books and Records delivered pursuant to this Section 9.15. The Books and Records may be delivered to Purchaser in electronic format stored on computer-related or other electronic media, provided however, that Vendor shall only be required to deliver data comprising Books and Records in the format in which such data is stored or maintained by Vendor or its applicable Affiliate at the time such data is delivered to Purchaser. Vendor shall use commercially reasonable efforts to provide such Books and Records as are in paper format at the date hereof to Purchaser as soon as reasonably practicable following Closing.

9.16 Excluded Owned IP License

On or before the Closing Date, at the request of Purchaser, Vendor or its applicable Affiliate will grant to the Purchased Entities a non-exclusive, paid-up right and license to access and use Excluded Owned IP (including source code) solely in connection with the operation of the Business by the Purchased Entities, provided however, that no license shall be required to be granted under this Section 9.16 to any such Excluded Owned IP which Vendor in its sole discretion and in good faith determines provides Vendor or any of its Affiliates (other than the Purchased Entities) significant competitive advantage to the businesses or operations of Vendor or any of its Affiliates (other than the Purchased Entities). Such license will be made effective on Closing and shall be substantially in the form of Exhibit B.

9.17 IT Related Matters

Each of the Parties agrees to the terms and conditions set forth in Schedule 9.17. At Closing, each of Vendor and Purchaser shall enter into the Transition Services Agreement.

9.18 Confidentiality

(a) After Closing, Vendor shall, and shall cause each of its Related Parties to, except to the extent otherwise expressly permitted by this Agreement, maintain in strict confidence all, and not use for commercial purposes (commercial purposes to not include any use thereof in connection with the preparation or audit of the financial statements of Vendor or any of its Affiliates after Closing or any such similar uses) or disclose any, Confidential Information concerning the Entity Assets and the Business. It is understood that Vendor shall not have any liability hereunder with respect to information that (i) is in or, through no fault of Vendor or any of its Related Parties, comes into the public domain, (ii) Vendor or any of its Related Parties is required to disclose by Applicable Law, Environmental Law or Governmental Authority, (iii) is or becomes available to Vendor or any of its Related Parties from a source (other than Purchaser or any of its Related Parties) which, to Vendor's knowledge, is not prohibited from disclosing such information by a legal, contractual or fiduciary obligation, or (iv) is disclosed by Vendor or any of its Related Parties with the consent of Purchaser or any of its Related Parties.

(b) Notwithstanding Section 9.18(a), Purchaser acknowledges that: (i) Vendor and its Affiliates are involved in widespread oil and gas activities and receive information and data from many different sources relating thereto, (ii) Vendor makes no representation or covenant that Vendor or its Affiliates will not continue such activities and continue to pursue opportunities involving such activities including activities and opportunities to which the Confidential Information referred to in Section 9.18(a) relates, (iii) Vendor's or its Affiliates' knowledge of such Confidential Information will not preclude Vendor or its Affiliates from such activities or from pursuing opportunities involving such activities, and (iv) the respective directors, officers, employees, agents and other representatives of Vendor and its Affiliates may retain mental impressions of such Confidential Information and shall not be precluded from working on projects involving any such activities or opportunities including activities and opportunities to which such Confidential Information relates because of their mental impressions. However, Vendor acknowledges that the intent of this Agreement is to ensure the confidentiality of such Confidential Information and to preclude the intentional use of such Confidential Information other than for the purposes permitted elsewhere in this Agreement.

(c) In the event that Vendor or any of its Related Parties is required by Applicable Law, Environmental Law or Governmental Authority to disclose any information contemplated by Section 9.18(a), Vendor shall, if permitted by Applicable Law, Environmental Law or Governmental Authority, promptly notify Purchaser in writing so that Purchaser may seek a protective order and/or other motion to prevent or limit the production or disclosure of such information. If such motion has been denied, or such disclosure is in any event so required, then the Person required to disclose such information may disclose only such portion of such information which, based on advice of Vendor's outside legal counsel, is required by Applicable Law, Environmental Law or Governmental Authority to be disclosed (provided that the Person required to disclose such information shall use all reasonable efforts to preserve the confidentiality of the remainder of such information). Vendor shall continue to be bound by its obligations pursuant to this Section 9.18 for any information that is not required to be disclosed, or that has been afforded protective treatment, pursuant to such motion.

(d) Purchaser shall, and shall cause each of its Related Parties to, maintain in strict confidence all, and not use or disclose any, Confidential Information concerning Vendor or any of Vendor's Related Parties (other than the Purchased Entities) which is not related to the Business or the Entity Assets and which Purchaser is not purchasing in connection with the transactions contemplated by this Agreement, which, for greater certainty, shall include any and all Confidential Information relating to the Excluded Assets and the operation thereof. It is understood that Purchaser shall not have any liability hereunder with respect to information that (i) is in or, through no fault of Purchaser or any of its Related Parties, comes into the public domain, (ii) Purchaser or any of its Related Parties is required to disclose by Applicable Law, Environmental Law or Governmental Authority, (iii) is or becomes available to Purchaser or any of its Related Parties from a source (other than Vendor or any of its Related Parties) which, to the best of Purchaser's knowledge, is not prohibited from disclosing such information by a legal, contractual or fiduciary obligation, or (iv) is disclosed by Purchaser or any of its Related Parties with the consent of Vendor or any of its Related Parties.

(e) In the event that Purchaser or any of its Related Parties is required by Applicable Law, Environmental Law or Governmental Authority to disclose any information contemplated by Section 9.18(d), Purchaser shall, if permitted by Applicable Law, Environmental Law or Governmental Authority, promptly notify Vendor in writing so that Vendor may seek a protective order and/or other motion to prevent or limit the production or disclosure of such information. If such motion has been denied, or such disclosure is in any event so required, then the Person required to disclose such information may disclose only such portion of such information which, based on advice of Purchaser's outside legal counsel, is required by Applicable Law, Environmental Law or Governmental Authority to be disclosed (provided that the Person required to disclose such information shall use all reasonable efforts to preserve the confidentiality of the remainder of such information). Purchaser shall continue to be bound by its obligations pursuant to this Section 9.18 for any information that is not required to be disclosed, or that has been afforded protective treatment, pursuant to such motion.

(f) Notwithstanding anything to the contrary contained herein, the obligations set forth in this Section 9.18:

(i) shall survive the Closing or the termination of this Agreement, and

(ii) shall continue for a period of four (4) years from the date hereof and shall then terminate.

(g) Nothing herein shall derogate from the rights and obligations of the Parties under the Confidentiality Agreements which shall continue in full force and effect, notwithstanding the provisions hereof, in accordance with its terms.

(h) This Section 9.18 shall not be applicable to disclosure, communication or provision of information to a Governmental Authority pursuant to a Tax audit, appeal or litigation.

9.19 Compliance with Privacy Laws

(a) Vendor acknowledges and confirms that Vendor and the Purchased Entities have complied, in all material respects, with Privacy Laws which govern the collection, use and disclosure of Personal Information disclosed to Purchaser pursuant to or in connection with this Agreement (the “**Disclosed Personal Information**”). Vendor hereby covenants and agrees, until Closing, to advise Purchaser of all purposes for which Disclosed Personal Information was initially collected from or in respect of the Entity Employees to whom that Disclosed Personal Information relates and all additional purposes where Vendor has notified the applicable Entity Employee of that additional purpose and disclosure of Personal Information, if any, unless that use or disclosure is permitted or authorized by law without notice to, or consent from, that Entity Employee, provided however, in such case, Vendor shall have advised Purchaser of the legislative provisions on which Vendor is relying.

(b) Before Closing, neither of the Parties shall use the Disclosed Personal Information for any purposes other than those related to the performance of this Agreement and the completion of the Purchase.

(c) Each of the Parties acknowledges and confirms that the disclosure of Personal Information is necessary for the purposes of determining if the Parties shall proceed with the Purchase and that the disclosure of Personal Information relates solely to the carrying on of the Business or the completion of the Purchase.

(d) Purchaser shall at all times keep strictly confidential all, and not disclose any, Disclosed Personal Information provided to it, and shall instruct those employees responsible for processing such Disclosed Personal Information to protect the confidentiality of that information. Purchaser shall ensure that access to the Disclosed Personal Information shall be restricted to those employees or service providers of Purchaser who have a *bona fide* need to access that information in order to fulfil their obligations in the course of their employment or in providing services to Purchaser.

(e) The Parties shall fully co-operate with one another, with the Entity Employees to whom the Personal Information relates, and any Governmental Authority charged with enforcement of Privacy Laws, in responding to inquiries, complaints, requests for access, and Claims in respect of Disclosed Personal Information.

(f) Purchaser undertakes, after Closing, to utilize, and to cause the Purchased Entities to utilize, the Disclosed Personal Information only for those purposes for which the Disclosed Personal Information was initially collected from or in respect of the Entity Employees.

(g) If Closing does not occur, Purchaser shall forthwith cease all use of the Disclosed Personal Information acquired by Purchaser in connection with this Agreement and will return to Vendor or, at Vendor’s request, destroy in a secure manner the Disclosed Personal Information (and any copies thereof) and, in the event of a request for such destruction, promptly provide Vendor with a certificate of a Senior Officer of Purchaser confirming such destruction.

(h) Purchaser acknowledges and agrees that Vendor and its Affiliates shall not be required to provide or disclose to Purchaser any Personal Information to the extent that doing so is not permitted under the internal data privacy rules or policies of Vendor or any of its Affiliates.

9.20 Dispute Resolution

(a) Subject to Section 3.5, if any Claim, controversy or dispute arises out of, pursuant to or in connection with this Agreement, including any question regarding its existence, breach, termination or validity and any non-contractual obligations arising out of or in connection with this Agreement (a “**Dispute**”), a party shall give the other party written notice of such Dispute (a “**Dispute Notice**”). If the parties are unable, within 30 days of the date of service of the Dispute Notice, to resolve the Dispute by management level good faith negotiations, any party may refer the Dispute to arbitration for final resolution under the Arbitration Rules of the LCIA (London Court of International Arbitration) (the “**LCIA Rules**”), which rules are deemed to be incorporated by reference into this Section 9.20.

(b) The tribunal shall constitute of three arbitrators. Vendor or Vendor and Vendor Guarantor together (if Vendor Guarantor is also a party) shall be entitled to nominate one arbitrator and Purchaser or Purchaser and Purchaser Guarantor together (if Purchaser Guarantor is also a party) shall be entitled to nominate one arbitrator.

(c) The third arbitrator, who shall act as chairman in accordance with the LCIA Rules, shall be nominated by the two arbitrators nominated by or on behalf of the parties to the arbitration. If the third arbitrator is not so nominated within 30 days of the date of nomination of the later of the two arbitrators appointed by the parties, the third arbitrator shall be appointed by the LCIA Court.

(d) The legal place or seat of arbitration shall be Calgary, Alberta, Canada. The language to be used in the arbitration shall be English.

(e) The tribunal’s award shall be final and binding on the parties.

(f) Notwithstanding Section 3.5(e)(xi), to the extent permitted by the LCIA Rules, any party may seek interim and/or conservatory measures from any court of competent jurisdiction.

Purchaser irrevocably appoints Bennett Jones LLP (the “**Purchaser’s Process Agent**”), with an office on the date hereof at 4500 Bankers Hall East, 855 2nd Street SW Calgary, Alberta, T2P 4K7, for the attention of Donald E. Greenfield, as its agent to receive on its behalf service of copies of a statement of claim and any other process which may be served in any Claim. That service may be made by delivering a copy of that statement of claim or other process to Purchaser in care of Purchaser’s Process Agent at Purchaser’s Process Agent’s address above or at such other address as Purchaser’s Process Agent shall have last notified Vendor by giving notice of such address in accordance with Section 13.4.

Vendor irrevocably appoints Fraser Milner Casgrain LLP (the “**Vendor’s Process Agent**”), with an office on the date hereof at 15th Floor, Bankers Court 850 — 2nd Street SW Calgary, Alberta, T2P OR8, for the attention of Mike Hurst, as its agent to receive on its behalf service of copies of a statement of claim and any other process which may be served in any Claim. That service may be made by delivering a copy of that statement of claim or other process to Vendor in care of Vendor's Process Agent at Vendor's Process Agent's address above or at such other address as Vendor's Process Agent shall have last notified Purchaser by giving notice of such address in accordance with Section 13.4.

9.21 Vendor Standards

(a) The Parties acknowledge that prior to Closing the Business had access to and used in the conduct of the Business certain Excluded IP, including documents defining and describing Vendor's standards, processes, procedures, practices and policies related to (i) Vendor's Operating Management System ("**OMS**") and related documentation, and (ii) Vendor's Engineering Technical Practices ("**ETPs**") and related documentation (collectively, the "**Vendor Standards**").

(b) Notwithstanding the fact that Vendor Standards are generally Excluded IP, Vendor hereby grants Purchaser a nonexclusive, paid-up, perpetual and irrevocable right and

license to continue to access and use, and to make copies of (in hardcopy or electronic form), those Vendor Standards which the Business has in its possession at Closing.

(c) The Vendor Standards, and all portions thereof, shall be used solely for the purpose of operating the Business, and shall not be used in connection with operating or conducting any other business.

(d) Vendor makes no representations or warranties, express or implied, and expressly disclaims any liability and responsibility for any use, interpretation or application by Purchaser or any of its Affiliates of any Vendor Standard at any time (including after the termination of the Agreement), or any advice, recommendations, consultations or opinions, in whatever form, provided to or acquired by Purchaser at any time in connection with the Vendor Standards (including from any of Vendor's employees, agents or contractors).

(e) Vendor Standards shall be deemed to be Vendor Confidential Information subject to the confidentiality provisions of Section 9.18 of this Agreement (except only to the extent the provisions of Section 9.18 are inconsistent with the right and license granted to Purchaser in Section 9.21(b)).

(f) After Closing, Vendor will not provide updates, improvements, amendments or otherwise support Vendor Standards.

9.22 Additional Contracts and Litigation Updates

Vendor shall report in reasonable detail to Purchaser no less often than once every month and in any event no later than five (5) Business Days prior to Closing regarding steps taken and other developments in regards to all:

(i) open litigation Claims described in Schedule 1.1H or Schedule 4.22(a), and

(ii) all litigation Claims involving any of the Purchased Entities that are commenced after October 1, 2011 where the amounts claimed or threatened exceeds or could reasonably be expected to exceed $300,000,

provided that doing so shall not risk the loss of privilege pertaining to the matter or otherwise prejudice Vendor or any of the Purchased Entities in respect of the matter or contravene any confidentiality obligations owed by any of the Purchased Entities to another Person.

9.23 Contracts for NGL Extraction Rights and Gas Supply

On or before the Closing Date, Vendor shall have caused the Corporation and the entity that will, at and after Closing, run the business currently being run by the Corporation's Integrated Supply and Trading Division, to enter into contracts in respect of all of the agreements, understandings and arrangements referred to in paragraph (c)(vii) of the definition of "Material Contracts", which contracts shall be on the same terms as are comprised in the said agreements, understandings and arrangements and shall also include such other terms (including without limitation provisions related to credit support) as would be customary in

contracts between Persons dealing at arm's length in regard to similar agreements, understandings and arrangements for the sale and purchase of gas in Canada.

9.24 Additional Financial Information

(a) Vendor shall deliver to Purchaser the financial statements, adjustments and other information described in Schedule 9.24(a), no later than 35 days from the date hereof. Such financial statements shall be prepared in accordance with IFRS consistently applied.

(b) Vendor shall deliver the financial statements, adjustments and other information described in the column entitled "Incremental Information Requirement" in Schedule 9.24(b), no later than the corresponding date specified in the column entitled "Date Required" in Schedule 9.24(b). Such financial statements shall be prepared in accordance with IFRS consistently applied.

(c) Except in respect of Material Claims under the indemnity contained in Section 10.1(a) for a breach of the representation and warranty set forth in Section 4.9 only, Vendor shall not have any liability to Purchaser or its Affiliates or any other Person in respect of the completeness or accuracy of any of the financial statements, adjustments and other information referred to in Sections 9.24(a) or (b), and Purchaser shall be liable for and shall indemnify and save harmless Vendor and the other Vendor Indemnified Parties against any and all Claims, including Third Party Claims, Liabilities and Losses suffered or incurred by or made against Vendor or any of the other Vendor Indemnified Parties as a result of any use of or reliance upon such financial statements, adjustments and other information by Purchaser or a third party who receives such financial statements, adjustments and other information from or through Purchaser or its Affiliates provided that Purchaser shall not be liable for and shall have no obligation to indemnify and save harmless Vendor and the other Vendor Indemnified Parties against any and all Claims, including Third Party Claims, Liabilities and Losses suffered or incurred or made against Vendor or any of the other Vendor Indemnified Parties as a result of the use of or reliance upon such financial statements, adjustments and other information by Vendor, the other Vendor Indemnified Parties or third parties who receive such financial statements, adjustments and other information from or through Vendor or its Affiliates.

(d) The costs of KPMG incurred by Vendor or its Affiliates in support of preparing pro forma adjustments as outlined in Schedule 9.24(a) and the costs KPMG and Ernst & Young incurred by Vendor or its Affiliates in connection with the preparation of any of the financial statements, adjustments and other information referred to in Sections 9.24(a) or (b) (other than the costs of Ernst & Young incurred in connection with their review of the Interim Financial Statements which costs shall be for the account of Vendor) shall be deducted from "Net Cash Provided by Operating Activities" as defined in or contemplated by section 2A of Schedule 1.1M. In the event Closing does not occur all such costs shall be paid by Purchaser to Vendor at the earlier of the time of termination of this Agreement and the Outside Date.

(e) Vendor and Purchaser shall cooperate to the extent reasonably required in connection with the preparation of the financial statements, adjustments and other information referred to in Sections 9.24(a) or (b).

9.25 Post Closing Cooperation and Access

(a) Within a period of twenty-four (24) months after Closing, Purchaser agrees, and agrees to cause Purchaser's Affiliates, including the Purchased Entities, to provide Vendor and its Affiliates with reasonable access after Closing to the Purchased Entities, the Books and Records, the Entity Assets and personnel for purposes of accounting, regulatory and other matters arising out of Vendor's prior direct and indirect ownership of the Purchased Entities, including for the preparation and filing of documents with Governmental Authorities.

(b) Within a period of twenty-four (24) months after Closing, Vendor agrees, and agrees to cause Vendor's Affiliates to provide Purchaser and its Affiliates, including the Purchased Entities, with reasonable access after Closing to the Excluded Books and Records (but only to extent such Excluded Books and Records reflect transactions that have occurred within a period of five (5) years prior to the date hereof and relate exclusively to the Business as conducted by the Purchased Entities) for purposes of accounting, regulatory and other matters arising out of Vendor's prior direct and indirect ownership of the Purchased Entities, including for the preparation and filing of documents with Governmental Authorities.

(c) In the event that, after Closing, any property, including any payment or correspondence, is delivered to Purchaser or its Affiliates and such property relates to the Excluded Assets, the Previously Owned Assets or the Non-NGL Business or otherwise properly belongs to Vendor or its Affiliates, then Purchaser shall hold such property in trust for, and cause its Affiliate to hold such property in trust for, Vendor and its Affiliates, promptly notify Vendor in accordance with Section 13.4 of the existence thereof and at the expense of Vendor promptly deliver such property to Vendor or its Affiliate. In the event that, after Closing, any property, including any payment or correspondence, is delivered to Vendor or its Affiliates and such property relates to the Entity Assets or the Business or otherwise properly belongs to Purchaser or its Affiliates, then Vendor shall hold such property in trust for, and cause its Affiliates to hold such property in trust for, Purchaser and its Affiliates, promptly notify Purchaser in accordance with Section 13.4 of the existence thereof and at the expense of Purchaser promptly deliver such property to Purchaser or its Affiliate.

9.26 Leased Rail Cars

Each of the Parties agrees to the terms and conditions set forth in Schedule 1.1L.

9.27 Regulatory Matter

The Parties acknowledge that BP Canada Energy Company and BP Canada Energy Resources Company have intervened in the "TCPL Mainline Application" to the National Energy Board of Canada ("**NEB**") which is described by the NEB as follows:

> NOVA Gas Transmission Ltd. and Foothills Pipe Lines Ltd. (TransCanada)
> Application for Approval of Restructuring and Mainline Final Tolls for 2012
> and 2013 Hearing Order RH-003-2011.

The Parties acknowledge that BP Canada Energy Company and BP Canada Energy Resources Company intend to intervene in TCPL's "NEXT Application" to the NEB described by the NEB as follows:

> NOVA Gas Transmission Ltd. (NGTL)
> Natural Gas Liquids Extraction (NEXT) Model
> Implementation Application dated 5 October 2011 (the Application)

The Parties agree that, if at the time of Closing either or both of the TCPL Mainline Application or the NEXT Application are still pending before the NEB, and BP Canada Energy Company or BP Canada Energy Resources Company did not intervene in such applications solely on the basis of their ownership of the Business, Vendor or an Affiliate of Vendor (other than the Purchased Entities) shall have the right to continue such interventions, or either of them, in its own name and own right by writing to the NEB to advise the NEB that it will be continuing the interventions commenced in the names of BP Canada Energy Company and BP Canada Energy Resources Company. For greater certainty, Purchaser shall be entitled to assume or continue any intervention that was made solely on the basis of the applicant's ownership of the Business.

9.28 Litigation Matter

In respect of the litigation Claim referred to as BP Canada Energy Resources Company v. ATCO Midstream (Court of Queen's Bench of Alberta Action No. 1001-15944) and notwithstanding anything to the contrary herein, any proceeds by way of judgment, settlement or otherwise, in favour of the Purchased Entities from such litigation shall, as to the amount of such proceeds applicable to the period prior to the Effective Date, be for the sole account of Vendor, and as to the amount of such proceeds applicable to the period on and after the Effective Date, be for the sole account of Purchaser.

9.29 Covenants in Schedules

Each Party agrees to perform the covenants and other agreements, and to discharge any obligations, in each case, on its part contained in any of the Schedules hereto in accordance with the terms thereof.

9.30 Contracts in Non-Purchased Entities

To the extent such Contracts are not held by a Purchased Entity, before Closing Vendor shall, or shall cause its Affiliates to:

(a) transfer all Futures Contracts listed in Schedule 4.16 to a Purchased Entity; and

(b) other than the Contracts referenced in clause 8(a) of Schedule 1.1B, and only if assignable, transfer to a Purchased Entity the contracts relating to any contractor whose prior duties under such contract have been exclusively utilized by the Business.

ARTICLE 10
INDEMNIFICATION

10.1 Mutual Indemnities for Breaches of Representations, Warranties and Covenants; Other Matters

(a) From and after the Closing, Vendor covenants and agrees to be liable for and to indemnify, defend and hold harmless Purchaser and its Related Parties (collectively, the "**Purchaser Indemnified Parties**"), and Purchaser covenants and agrees to be liable for and to indemnify, defend and hold harmless Vendor and its Related Parties (collectively, the "**Vendor Indemnified Parties**") (the Party covenanting and agreeing to indemnify the other Party and its Related Parties being called in this Agreement the "**Indemnifying Party**" and the Party or Related Party being indemnified being called in this Agreement the "**Indemnified Party**"), from and against any Claims which may be made or brought against any of the Indemnified Parties and any Liabilities and Losses which they may suffer or incur, in any way, directly or indirectly, caused by, arising from, incurred in connection with or relating to any breach of any covenant on the part of the Indemnifying Party under this Agreement or any inaccuracy or incorrectness of any representation or warranty of the Indemnifying Party contained in this Agreement or any Closing Document delivered by the Indemnifying Party.

(b) Any obligation of indemnification pursuant to this Article 10 shall be subject to:

(i) the limitations and other provisions set forth in Article 6,

(ii) the provisions of this Article 10,

(iii) the limitation that, for Claims made or Liabilities or Losses incurred in connection with any inaccuracy or incorrectness of any representation or warranty contained herein or breach of any covenant contained herein, the Indemnifying Party shall not be required to pay any such amount until the aggregate amount is finally adjudicated or agreed as being payable by that Indemnified Party and, if applicable, that final amount exceeds the thresholds set out in Article 6, and is then subject to the limits set forth in Article 6, and

(iv) the limitation that, for any Claim, Liability or Loss in respect of which a Purchaser Indemnified Party is the Indemnified Party, if specific provision or reserve was made for that Claim, Liability or Loss in the Financial Statements or the Working Capital Statement, then the amount of that provision or reserve shall also be deducted from that Claim, Liability or Loss before determining the amount of that Claim, Liability or Loss which may be subject to indemnification under this Agreement.

(c) Without derogating from Sections 6.1, 6.2 and 6.3, for purposes of calculating the amount of any Losses for which indemnification is available under Sections 10.1(a), 10.4 and 10.5, Vendor's representations and warranties shall be read and applied without regard to, and shall be deemed not to be qualified by, any reference in the text thereof to "materiality", "material", "materially", "material respects", "Material Adverse Effect" or similar materiality qualifiers set forth herein (other than the word "Material" in the

expressions "Material Claim", "Material Consent", "Material Contract" or "Material Facility", as part of the defined term); provided, however, that the term "material respects" or the word "material", as applicable, shall continue to apply as a modifier with respect to the required content of the Schedules contemplated by Section 4.23(h) and Section 4.24(a).

10.2 Purchaser Indemnity Relating to Environmental Liabilities and Abandonment and Reclamation Obligations

In addition to and without limiting its other obligations to indemnify Vendor Indemnified Parties from and after the Closing, and without in any way limiting the rights of Purchaser hereunder in respect of a breach of Section 4.21 by Vendor or the obligations of Vendor pursuant to Sections 10.4 and

10.5, Purchaser covenants and agrees with Vendor to be liable for and to indemnify, defend and hold harmless Vendor Indemnified Parties from and against any and all:

(a) Purchaser Indemnified Environmental Liabilities regardless of whether such Purchaser Indemnified Environmental Liabilities arose or accrued, or are attributable to time periods, prior to, on or subsequent to the Closing Date, and

(b) Purchaser Indemnified Abandonment and Reclamation Obligations regardless of whether such Purchaser Indemnified Abandonment and Reclamation Obligations occurred, arose or accrued, or are attributable to time periods, prior to, on or subsequent to the Closing Date.

Purchaser, on its behalf and on behalf of its Affiliates, including the Purchased Entities, does hereby release, remise and forever discharge each and every Vendor Indemnified Party from any and all Claims, Liabilities and Losses of any kind in any way, directly or indirectly, caused by, arising from, incurred in connection with or relating to Purchaser Indemnified Environmental Liabilities and Purchaser Indemnified Abandonment and Reclamation Obligations, including all Claims for contribution or indemnity under Applicable Laws or Environmental Laws or in equity or otherwise, which may be asserted or incurred now or in the future (or both) and that in any way relate to or arise out of Purchaser Indemnified Environmental Liabilities or Purchaser Indemnified Abandonment and Reclamation Obligations, regardless of whether those Purchaser Indemnified Environmental Liabilities or Purchaser Indemnified Abandonment and Reclamation Obligations occurred, arose or accrued, or are attributable to time periods, prior to, on or subsequent to the Closing Date; and Purchaser covenants on its behalf, and on behalf of its Affiliates, including the Purchased Entities, not to make any Claim or other demand, or institute any action or other proceeding against any Vendor Indemnified Party for indemnity or contribution for or in respect of any of those Purchaser Indemnified Environmental Liabilities or Purchaser Indemnified Abandonment and Reclamation Obligations or against a Person where a Claim by that Person for contribution or indemnity may be brought against a Vendor Indemnified Party. Purchaser represents and warrants that it has the authority to bind its Affiliates as herein provided.

Neither Purchaser nor any of its Affiliates, including the Purchased Entities, shall have any rights to recovery, indemnification or contribution from or against any Vendor Indemnified Party for Purchaser Indemnified Environmental Liabilities or Purchaser Indemnified Abandonment and Reclamation Obligations under this Agreement, under Applicable Laws or any past, present or

future Environmental Laws, in equity or otherwise, and all rights and remedies which Purchaser and its Affiliates, including the Purchased Entities, may have at or under Applicable Law or any past, present or future Environmental Law or in equity or otherwise, including any right of contribution or reimbursement, against any Vendor Indemnified Party with respect to any such Purchaser Indemnified Environmental Liabilities or Purchaser Indemnified Abandonment and Reclamation Obligations are expressly waived.

10.3 Purchaser Indemnity Relating to the Business and Other Matters

In addition to and without limiting its other obligations to indemnify Vendor Indemnified Parties from and after the Closing, Purchaser covenants and agrees with Vendor to be liable for and to indemnify, defend and hold harmless Vendor Indemnified Parties from and against any and all past, present and future Liabilities (and any and all Losses associated with or relating to such Liabilities), in any way, directly or indirectly, caused by, arising from, incurred in connection with or relating to:

(a) the Business, any of the Purchased Entities or any of the Entity Assets, in each case other than those Claims, Liabilities or Losses which are the subject of indemnification provided by Vendor as set out in Sections 10.1(a), 10.4, 10.5 or Article 11,

(b) any Existing Credit Support Obligations provided by Vendor or any of its Affiliates (other than the Purchased Entities) to any Credit Support Counterparty for the benefit of any of the Purchased Entities or their predecessors or successors in interest in connection with or relating to the Business, and

(c) any indemnities, whether by Contract or otherwise, provided by Vendor or any of its Affiliates (other than the Purchased Entities) to any Person for the benefit of any of the Purchased Entities or their predecessors or successors in interest in connection with or relating to the Business,

and any and all Claims associated with or relating to any of the foregoing.

10.4 Vendor Indemnity Relating to Certain Liabilities

(a) In addition to, and without limiting its other obligations to indemnify Purchaser Indemnified Parties from and after the Closing, Vendor covenants and agrees with Purchaser to be liable for and to indemnify, defend and hold harmless Purchaser Indemnified Parties from and against any and all:

(i) Vendor Indemnified Environmental Liabilities,

(ii) Vendor Indemnified Abandonment and Reclamation Obligations,

(iii) Vendor Indemnified Litigation Claims,

(iv) fines or penalties, or Claims relating thereto, relating to Vendor’s or its Affiliates’ operation of the Entity Assets prior to Closing, and

(v) other than any Liabilities arising directly and solely as a result of changes to the Reorganization that would not have been made, or that would not in the future be made, but for the request of Purchaser, Liabilities arising out of or attributable directly and solely to the conduct of the Reorganization but only to the extent such Liabilities would not have arisen but for the Reorganization.

(b) In addition to, and without limiting its other obligations to indemnify Purchaser Indemnified Parties from and after the Closing, Vendor covenants and agrees with Purchaser to be liable for and to indemnify, defend and hold harmless Purchaser Indemnified Parties from and against any and all Environmental Liabilities, other than future Environmental Liabilities and Environmental Liabilities arising or accruing on or after the Closing Date, and Liabilities for which provision has been made in the Financial Statements, that would, but for this Section 10.4(b), be Purchaser Indemnified Environmental Liabilities, of which, as at the date hereof, Vendor was aware (as contemplated by Section 1.3(a)) but which Vendor had not disclosed to Purchaser in the environmental section of a Data Room to which Purchaser has had access on or before the date hereof provided such disclosure is sufficient to put a reasonable environmental professional on notice as to the existence of a potential Environmental Liability.

(c) In addition to, and without limiting its other obligations to indemnify Purchaser Indemnified Parties from and after the Closing, Vendor covenants and agrees with Purchaser to be liable for and to indemnify, defend and hold harmless Purchaser Indemnified Parties from and against litigation Claims, other than Tax Claims, that are not described, referred to or listed on Schedule 4.22(a) that have been served on any of the Purchased Entities after the date hereof where the amounts claimed exceeds or could reasonably be expected to exceed $300,000 to the extent the Loss attributable thereto is as a result of:

(i) events or circumstances that have taken place or occurred prior to the Effective Time, but in any case this indemnity shall only apply to Loss attributable thereto to the extent incurred prior to the Effective Date, or

(ii) events or circumstances that have taken place or occurred after the Effective Time but prior to the Closing Time, unless the acts or omissions that resulted in or gave rise to such events or circumstances were consented to by Purchaser, but in any case this indemnity shall only apply to Loss attributable thereto to the extent caused by the gross negligence or wilful misconduct of any of the Purchased Entities.

10.5 Vendor Indemnity Relating to the Non-NGL Business

In addition to and without limiting its other obligations to indemnify Purchaser Indemnified Parties from and after the Closing, Vendor covenants and agrees with Purchaser to be liable for and to indemnify, defend and hold harmless Purchaser Indemnified Parties from and against any and all past, present and future Liabilities of any of the Purchased Entities or any of their successors in interest (and any and all Losses associated with or relating to such Liabilities) in any way, directly or indirectly, caused by, arising from, incurred in connection with or relating to the Non-NGL Business, the Previously Owned Assets or the Excluded Assets and any and all

Claims associated with or relating to the Non-NGL Business, the Previously Owned Assets or the Excluded Assets, provided however, notwithstanding the foregoing or anything else herein contained Vendor shall not have any obligation to indemnify Purchaser or any other Purchaser Indemnified Party in relation to: (i) any Environmental Liabilities or Abandonment and Reclamation Obligations incurred under Previously Owned Asset Agreements that relate to Entity Assets, and (ii) any pension plan for the benefit of any current or former employee of any of the Purchased Entities, including any of the pension and other Employee Benefit Arrangements referred to in Part C of Schedule 1.1G, provided further however, that the foregoing shall not derogate from the indemnity contemplated to be provided, at the election of Vendor, in Part C of Schedule 1.1G. For the avoidance of doubt, the indemnity set forth in this Section 10.5 with respect to the Previously Owned Assets covers and includes any Liabilities and Losses of the Purchased Entities arising out of or related to [*****], subject to clause (i) above.

10.6 Procedures Relating to Indemnification Between Vendor and Purchaser

Except in respect of Third Party Claims (which shall be governed by Section 10.7), following the discovery of any facts or conditions which could reasonably be expected to give rise to a Claim, Liability or Loss for which indemnification is provided under this Agreement, the Indemnified Party shall, as promptly as reasonably possible thereafter, provide written notice ("**Indemnification Notice**") to the Indemnifying Party, setting forth the specific facts and circumstances, in reasonable detail, relating to that Claim, Liability or Loss and the amount of that Claim, Liability or Loss (or a reasonable, good-faith estimate thereof if the actual amount is not known or not capable of reasonable calculation), provided however, that failure to give that Indemnification Notice on a timely basis shall not affect the indemnification provided hereunder except to the extent the Indemnifying Party shall have been actually and materially prejudiced as a result of that failure. Notwithstanding the foregoing:

(a) a Purchaser Indemnified Party shall not be entitled to make a Claim against Vendor under this Article 10 in respect of a breach of any covenant or any inaccuracy or incorrectness of any representation or warranty (a "**default**") unless and until:

(i) Purchaser shall have provided Vendor written notice of the default, and

(ii) if that default is of a nature capable of being cured, Vendor shall have failed to cure it within 60 days after Vendor's receipt of such Purchaser's notice, and

(b) a Vendor Indemnified Party shall not be entitled to make a Claim against Purchaser under this Article 10 in respect of a default unless and until:

(i) Vendor shall have provided Purchaser written notice of the default, and

(ii) If that default is of a nature capable of being cured, Purchaser shall have failed to cure it within 60 days after Purchaser's receipt of such Vendor's notice.

10.7 Indemnification Procedures for Third Party Claims (other than Tax Claims)

(a) In the case of Third Party Claims with respect to which indemnification is sought hereunder, the Indemnified Party shall give prompt written notice of any such Claim made on it, and in any event within 10 days after it receives notice of any such Claim, to the Indemnifying Party stating the nature and basis for that Claim and the nature and basis of the Claim by Purchaser or Vendor, as the case may be, for indemnification hereunder. A failure to give that notice within that period shall not preclude the Indemnified Party from obtaining such indemnification but its right to indemnification shall be reduced to the extent that any such delay materially prejudiced the defence of the Claim or materially increased the amount of liability, whether determined through adjudication or settlement, or cost of defence.

(b) The Indemnifying Party shall have the right, by notice to the Indemnified Party given not later than 15 days after its receipt of the notice described in Section 10.7(a), to assume the control of the defence, compromise and settlement of that Claim so long as (i) the Indemnifying Party conducts the defence of the Claim in good faith, and (ii) such assumption shall, by its terms, be without material cost to the Indemnified Party, provided however, if the Claim involves the seeking of an injunction or other similar equitable non-monetary relief against the Indemnified Party, the Indemnified Party shall have the right to control the defence of that part of the Claim. If the Indemnifying Party assumes the control of the defence, compromise and settlement of such Claim, as against the Indemnified Party, it will be conclusively established for the purposes of this Agreement that those Claims are within the scope of the indemnification set out in this Article 10 and the Indemnifying Party shall reimburse the Indemnified Party for all reasonable legal fees and expenses on a solicitor and its own client basis in connection therewith incurred by the Indemnified Party prior to that assumption by the Indemnifying Party. The Indemnifying Party shall thereafter keep each Indemnified Party reasonably informed with respect to the status of that Claim. If the Indemnified Party is required to respond to, or take any action in respect of, a Claim prior to the Indemnifying Party electing to assume control of the defence of such Claim, such response or action shall not affect the Indemnifying Party’s right to assume control of the defence of such Claim. If the Indemnifying party assumes control of the defence of such Claim, the response or action of the Indemnified Party shall be deemed ratified by the Indemnifying Party provided such response or action was taken in good faith consistent with the interests of the Indemnifying Party.

(c) On the assumption of control of any Claim by the Indemnifying Party pursuant to Section 10.7(b), the Indemnifying Party shall diligently proceed with the defence, compromise or settlement of that Claim at its sole risk, cost and expense and, in connection therewith, the Indemnified Party shall cooperate fully, but at the expense of the Indemnifying Party with respect to any out-of-pocket expenses incurred, to make available to the Indemnifying Party all pertinent information and witnesses under the Indemnified Party’s control and take such other steps as in the opinion of counsel for the Indemnifying Party are reasonably necessary to enable the Indemnifying Party to conduct that defence. The Indemnifying Party shall not settle that Claim unless that settlement includes, as a term thereof: (i) the giving by the claimant or the plaintiff of a full and complete release of the Indemnified Party from any and all liability with respect to that Claim; and (ii) other than with respect to the Non-NGL Business related litigation Claims or litigation Claims identified as Non-NGL in Schedule 1.1H, if Purchaser or the Purchaser Indemnified Parties are the Indemnified Party and any terms of the proposed settlement will significantly impact the Business following Closing, the consent of

Purchaser, which consent shall not be unreasonably withheld. As long as the Indemnifying Party is contesting any such Claim in good faith and on a timely basis, the Indemnified Party shall not pay or settle any such Claim without the consent of the Indemnifying Party. If the defendants in any such Claim shall include both an Indemnified Party and the Indemnifying Party and such Indemnified Party shall have reasonably concluded that counsel selected by the Indemnifying Party has a conflict of interest or that, because of the availability of different or additional defences to that Indemnified Party, the interests of the Indemnified Party are best served by having separate defence counsel, that Indemnified Party shall have the right to select separate counsel to participate in the defence of that Claim on its behalf at the expense of the Indemnifying Party (to the extent only that the fees and expenses of such separate counsel are reasonably allocable to that part of the Claim for which the Indemnifying Party is liable hereunder), but only to the extent such Claim gives rise to indemnification hereunder, and provided further, that the Indemnifying Party shall not be obligated to pay the expenses of more than one separate counsel for all Indemnified Parties. Notwithstanding anything to the contrary contained herein, an Indemnifying Party may not, without the consent of the Indemnified Party (which consent may be withheld in its sole discretion) agree to any kind of non-monetary relief which would burden the Indemnified Party or its assets.

(d) If the Indemnifying Party shall fail to notify the Indemnified Party of its desire to assume control of the defence, compromise or settlement of any Claim within the period of time prescribed above in Section 10.7(b), or shall notify the Indemnified Party that it will not assume control of the defence, compromise or settlement of any such Claim, then the Indemnified Party may assume the control of the defence, compromise and settlement of any such Claim, at the expense of the Indemnifying Party, in which event it may do so in such manner as it may deem appropriate and the Indemnifying Party shall be bound by any determination made in that Claim or any settlement thereof effected by the Indemnified Party, provided that any such determination or settlement shall not affect the right of the Indemnifying Party to otherwise dispute the Indemnified Party’s claim for indemnification. The Indemnifying Party shall be permitted to join in the defence of that Claim and to employ counsel at its own expense.

(e) The final determination of any Claim governed by this Section 10.7 will be binding and conclusive on the Parties as to the validity or invalidity, as the case may be, of that Claim.

(f) Amounts payable by the Indemnifying Party to the Indemnified Party in respect of any Claims for which the Indemnified Party is entitled to indemnification under this Section 10.7 shall be payable by the Indemnifying Party as incurred by the Indemnified Party.

(g) This Section 10.7 shall not apply to Tax Claims.

10.8 Holding of Indemnities

Vendor and Purchaser shall hold the indemnities contained in this Article 10 in trust for the benefit and on behalf of Vendor Indemnified Parties or Purchaser Indemnified Parties, respectively, and may enforce those indemnities on their behalf.

10.9 Claims Net of Insurance

The amount of any and all Claims, Liabilities and Losses under this Article 10 and elsewhere under this Agreement shall be determined net of any amounts recovered at any time pursuant to valid claims by the Indemnified Party (such amounts to be reduced by any Tax payable by the Indemnified Party in respect of such amounts) under insurance policies, other indemnities and other reimbursement arrangements (other than self insurance) with respect to those Claims, Liabilities and Losses, which claims and recoveries the Indemnified Party shall use all commercially reasonable efforts to fully pursue and collect. Provided that the Indemnifying Party has satisfied its indemnification obligations under Article 10, each Indemnified Party hereby waives, or will use reasonable commercial efforts to procure the waiver of, any subrogation rights that its insurer or such other Person may have against the Indemnifying Party and any of the Indemnifying Party's Related Parties with respect to any indemnifiable Claims, Liabilities and Losses in respect of which the Indemnifying Party has fulfilled its indemnity obligations hereunder.

10.10 Mitigation

Each Indemnified Party shall take all reasonable steps and use all commercially reasonable efforts to mitigate any and all Claims, Liabilities and Losses. Without limiting the generality of the foregoing, if Vendor has agreed to indemnify a Purchaser Indemnified Party hereunder for any Claim, Liability or Loss and such Claim, Liability or Loss can be mitigated by the execution and delivery of any instrument in writing or other document or the filing thereof with any Governmental Authority or other Person, Purchaser will, and will cause the Purchased Entities and other Purchaser Indemnified Parties to, as applicable, execute and deliver any such instrument or document or file such instrument or document with any such Governmental Authority or other Person, in each such case, as directed by Vendor in writing. Vendor agrees to indemnify Purchaser for all Liability incurred by Purchaser or the Purchased Entities in connection therewith.

10.11 Adjustment to Purchase Price

Any indemnity payment under this Agreement shall be treated as an adjustment to the Purchase Price.

10.12 Subrogation

Each Indemnified Party shall assign to the Indemnifying Party and subrogate the Indemnifying Party to all its rights and remedies against any Person (other than, with respect to rights and remedies of Vendor and Purchaser, any such rights and remedies against its Related Parties, and, in respect of any other Indemnified Party, any rights and remedies against its Affiliates) in respect of any payment made by the Indemnifying Party to the Indemnified Party pursuant to this Agreement. Each Indemnified Party shall provide all reasonable cooperation and assistance required by the Indemnifying Party in making and prosecuting any Claim for recovery against that Person to the extent that payment is made by the Indemnifying Party. No Indemnified Party shall knowingly take any action to impair any such right or remedy of the Indemnifying Party to recover any such payment.

10.13 Access and Co-operation in Respect of Vendor Indemnified Matters

(a) Purchaser agrees, and agrees to cause Purchaser's Affiliates, including the Purchased Entities, to provide Vendor and its Affiliates with reasonable access after Closing to the Purchased Entities, the Books and Records, the Entity Assets and personnel for purposes of addressing Claims for which indemnity is provided hereunder by Vendor, including Vendor Indemnified Matters, and Tax, accounting, regulatory and other matters arising out of Vendor's prior direct and indirect ownership of the Purchased Entities.

(b) Purchaser further agrees, and agrees to cause Purchaser's Affiliates, including the Purchased Entities, to allow Vendor and its Affiliates and its and their representatives to have access to personnel of Purchaser and Purchaser's Affiliates, including the Purchased Entities, familiar with matters relating to Vendor Indemnified Matters to assist in the defence or prosecution of Claims related to such Vendor Indemnified Matters and in connection with Tax, accounting, regulatory and other matters arising out of Vendor's prior direct and indirect ownership of the Purchased Entities. Vendor shall reimburse Purchaser for Purchaser's out of pocket expenses in connection therewith.

(c) At Vendor's reasonable request, and provided Vendor has acknowledged its indemnification obligation with respect to the relevant Vendor Indemnified Matter, Purchaser shall deliver to Vendor or its designee one or more irrevocable powers of attorney from Purchaser or Purchaser's Affiliates, including the Purchased Entities, authorizing Vendor or its designee to take such actions and execute and deliver such documents for and on behalf of Purchaser and its Affiliates, including the Purchased Entities, as Vendor reasonably requires in connection with the prosecution or defence of any Vendor Indemnified Matters including the filing of claims and the conduct of all legal proceedings relating thereto. The intent and purpose of this Section 10.13(c) is to provide Vendor with all reasonable power and authority to limit or otherwise manage its Liability in connection with any Vendor Indemnified Matter provided Purchaser is held harmless in respect thereof.

(d) In respect of all Vendor Indemnified Litigation Vendor or its Affiliates shall have the exclusive right to control the defence, compromise and settlement of such litigation and the settlement or compromise of any Claim in connection therewith, provided that, other than with respect to the Non-NGL Business related litigation Claims or litigation Claims identified as Non-NGL in Schedule 1.1H, if Purchaser or the Purchaser Indemnified Parties are the Indemnified Party and any terms of the proposed settlement will significantly impact the Business following Closing, Vendor shall obtain the consent of Purchaser, which consent shall not be unreasonably withheld. The Litigation Support Agreement shall apply to the Vendor Indemnified Litigation.

10.14 Assignment of Benefits under Indemnified Litigation Claims

In connection with any Indemnified Litigation Claim, Vendor shall be entitled to any and all proceeds and benefits arising in connection with or under the litigation related to such Claim, including the proceeds of any counterclaim, third party or other claim over or any award of costs, and Purchaser shall, and shall cause each of Purchaser Indemnified Parties, including the

Purchased Entities, as necessary, to, execute and deliver all such documents, including documents of assignment, as may be reasonably requested by Vendor to give full effect to this Section 10.14.

10.15 Litigation Support Agreement

At Closing, each of Vendor and Purchaser shall enter into the Litigation Support Agreement.

10.16 No Waiver of Indemnification Rights

Notwithstanding anything to the contrary contained herein, if Closing occurs, Closing shall not be considered or deemed to be a waiver by either Party of its rights to indemnification for a breach of this Agreement by the other Party.

ARTICLE 11
TAX MATTERS

11.1 Liabilities for Taxes

(a) After Closing, and subject to the terms of this Article 11, Vendor shall be liable for, shall pay and shall indemnify, defend and hold harmless Purchaser and the Purchased Entities from and against:

(i) all income Taxes or amounts related to income Taxes payable by a Purchased Entity, in excess of amounts paid by the Purchased Entity prior to Closing or Vendor or any of its Affiliates (other than a Purchased Entity) at any time on account of such Taxes, for taxation years of the Purchased Entity ending before the Closing Date, or, for a taxation year that does not end before the Closing Date, all such income Taxes attributable to the period before the Closing Date, for greater certainty, including income taxes payable by a Purchased Entity for taxation years ending before Closing Date that are attributable to or arise directly or indirectly therefrom from the Permitted Pre Closing Actions,

(ii) all other Taxes (and for greater certainty, excluding amounts that are, or relate to, income Taxes) payable by a Purchased Entity, in excess of amounts paid by the Purchased Entity prior to Closing or Vendor or any of its Affiliates (other than a Purchased Entity) at any time on account of such Taxes, attributable to periods ending before the Closing Date (whether or not such periods coincide with the end of a taxation year), but excluding all other Taxes in respect of the Business and the Entity Assets after the Effective Time, and excluding Taxes that have been included in the computation of the Working Capital Amount, and

(iii) all Taxes of Vendor and any Affiliate thereof (other than the Purchased Entities) for any taxation year or period,

in all such cases:

(iv) to the extent that such Taxes are not attributable to actions or omissions by, or at the direction of, Purchaser or any of its Affiliates, provided that for greater

certainty, Taxes that are attributable to or arise because of a reasonable position taken by a Purchased Entity in a Tax return filed in respect of any Taxation year or period that ends after the Closing Date will not, in and of itself, be considered to be attributable to the actions or omissions of, or at the direction of, of Purchaser or any of its Affiliates.

(b) After Closing, and subject to the terms of this Article 11, Purchaser shall be liable for, shall pay and shall indemnify, defend and hold harmless Vendor and its Affiliates from and against all Taxes payable by the Purchased Entities for taxation years or periods other than those referred to in Section 11.1(a)(i) or (ii).

(c) Vendor shall be liable for, shall pay and shall indemnify, defend and save harmless Purchaser and its Affiliates from and against all stock transfer, sales, use, documentary, stamp and other similar Taxes (“**Transfer Taxes**”) incurred in connection with the sale and transfer of the Shares to Purchaser. Purchaser shall file all necessary Tax Returns and other documentation with respect to such Transfer Taxes, and Vendor shall cooperate with Purchaser with respect thereto and, if required by Law, execute Tax Returns related thereto.

(d) If there is any change on or after the Closing Date to an item of income, gain, loss, deduction or credit that results in an increase in any Tax in respect of which Vendor has an indemnification obligation under Section 11.1(a)(i) or (ii), and that change results in a Tax Benefit to Purchaser or any of the Purchased Entities in one or more taxation years or periods in respect of which Purchaser has an indemnification obligation under Section 11.1(b), Vendor’s liability pursuant to Section 11.1(a)(i) or (ii) shall be reduced to the extent of such Tax Benefit.

“**Tax Benefit**” means the net present value, calculated by discounting at an interest rate of 3%, the sums of the Tax Rate multiplied by each amount that becomes deductible in computing taxable income of a Purchased Entity (each such sum being a “**Tax Savings Amount**”) or successors thereto in taxation years or periods in respect of which Purchaser has an indemnification obligation under Section 11.1(b) (a “**Timing Difference**”) where such deductible amounts arise because of a change to an item of income, gain, loss, deduction or credit that results in an increase in Tax in respect of which Vendor has an indemnification obligation under Section 11.1(a)(i); and "**Tax Rate**" means, in respect of the Canadian Purchased Entities and successors thereto, the Canadian federal corporate rate of Tax on income plus the arithmetic mean of the applicable corporate income Tax rates for the provinces of Alberta and Ontario, for any relevant period of time, and for all other entities, zero.

In determining the amount of any Tax Savings Amounts under this Section 11.1(d), deductible amounts in computing taxable income shall be calculated on the basis that the Purchased Entity is able to deduct amounts arising from the Timing Difference at the earliest time permissible under the Tax Act and realizes a reduction of tax or obtains a refund at that time.

11.2 Tax Returns

(a) Vendor shall cause to be prepared and filed on a timely basis all Tax Returns (if any) for the Purchased Entities for taxation years which end before the Closing Date. Vendor shall be entitled, in preparing such Tax Returns, to claim the maximum allowable amount in respect of discretionary deductions. Vendor and Purchaser agree that an election pursuant to Subsection 256(9) of the Tax Act shall not be made with respect to the Purchase.

(b) Purchaser shall be responsible for filing all Tax Returns for the Purchased Entities for taxation years or periods which end on or after the Closing Date.

(c) After Closing, Purchaser shall, and shall cause the Purchased Entities to cooperate fully with Vendor and Vendor's Affiliates and make available to Vendor and Vendor's Affiliates in a timely fashion such data and other information as may reasonably be required for the preparation of any of the Tax Returns referred to in Section 11.2(a) and shall preserve that data and other information until the expiration of any applicable limitation period under any Applicable Laws with respect to Taxes.

(d) Purchaser shall not, and shall not allow any of its Affiliates including the Purchased Entities to, amend, refile or otherwise modify or grant an extension of any statute of limitations with respect to any Tax Return or election for any of the Purchased Entities for any taxation years or periods referred to in Section 11.1(a)(i) or (ii) and shall not request, and shall not allow any of the Purchased Entities to request, an audit or assessment of any such Tax Return or election, in either case, without prior written consent of Vendor, which consent may be arbitrarily withheld.

(e) After Closing Vendor shall make available to Purchaser, on a timely basis, all information relating to potential Tax liabilities of the Purchased Entities that Purchaser requires to meet its financial reporting obligations for its audited financial statements prepared in accordance with U.S. GAAP.

11.3 Remittance of Tax

(a) Vendor or an Affiliate of Vendor shall pay and remit, within the statutory limitation periods applicable to the payment of Taxes, to the appropriate Tax Authority:

(i) the full amount of all Taxes owed to the applicable Tax authority as a result of any assessment or reassessment in respect of any taxation year or period in respect of which Vendor has an indemnification obligation under Section 11.1(a)(i) or (ii), and

(ii) any Taxes due in respect of the Tax Returns referred to in Section 11.2(a),

whether or not the full amount is required to be paid and whether or not Vendor intends to contest the amount of such Taxes, any such payment or remittance being an adjustment to the Purchase Price hereunder.

(b) Purchaser and its Affiliates including the Purchased Entities shall not request that any Tax authority apply any amount of Tax paid by a Purchased Entity prior to the Closing Date, or by Vendor or an Affiliate of Vendor on or after the Closing Date pursuant to Section 11.3(a), to any Tax year or period for which Purchaser is responsible pursuant to Section 11.2(b) without written consent from Vendor or an Affiliate of Vendor, which consent may be arbitrarily withheld. Where any Tax authority applies an amount of Tax paid by a Purchased Entity prior to the Closing Date or by Vendor or an Affiliate of Vendor after the Closing Date pursuant to Section 11.3(a) to a Tax year or period for which Purchaser is responsible pursuant to Section 11.2(b), such amount shall be paid to Vendor pursuant to the terms of Section 11.4.

11.4 Tax Refunds

(a) Vendor shall be entitled to any refund of (or credit for) Taxes and all related interest (less income Tax on that interest at a rate of 26% where the recipient is resident in Canada and 37% where the recipient is resident in the U.S. but only to the extent that such interest is taxable) for any taxation year or period in respect of which Vendor has an indemnification obligation under Section 11.1(a)(i) or (ii), whether as a result of an assessment, reassessment or otherwise. Purchaser shall promptly provide Vendor or an Affiliate of Vendor designated in writing by Vendor all notices of assessment or reassessment relating to the Purchased Entities in respect of any taxation years or periods referred to in Section 11.1(a)(i) or (ii).

(b) If Taxes in respect of any taxation year or period in respect of which Vendor has an indemnification obligation under Section 11.1(a)(i) or (ii) are less than the amount, in respect thereof remitted to a Tax authority by the Purchased Entities prior to the Closing Date or by Vendor or an Affiliate of Vendor on or after the Closing Date pursuant to Section 11.3(a), Purchaser shall pay or cause the Purchased Entities to pay the difference plus all related interest (less income Tax on that interest at a rate of 26% where the recipient is resident in Canada and 37%

where the recipient is resident in the U.S. but only to the extent that such interest is taxable) to Vendor or an Affiliate of the Vendor designated in writing by the Vendor.

(c) Payments made pursuant to Section 11.4(b) shall be treated as an adjustment to the Purchase Price.

(d) Payments required to be made under Section 11.4(b) shall be paid to Vendor or an Affiliate of Vendor designated in writing by Vendor within 15 days of receipt by Purchaser or the applicable Purchased Entity of the refund of the Taxes or the application of the refund by the applicable Tax authority to a taxation year for which Purchaser has an indemnification obligation under Section 11.1(b).

11.5 Confidentiality of Tax Information

Unless otherwise required by Applicable Laws, Environmental Laws or Governmental Authorities, each Party shall, and shall cause its Representatives to, keep confidential any non-public Tax information, records, and documents disclosed by the other Party, or to which that first mentioned Party has received or been granted access pursuant to this Article 11 and shall

not use that Tax information for any purpose other than making the determinations and taking such other actions contemplated by this Article 11.

11.6 No Section 338 Election

Purchaser shall not make, or cause or allow to be made, an election under section 338(g) of the Code with respect to the Purchase of the Shares or the deemed purchase of the shares of any eligible subsidiary.

11.7 Tax Claims

(a) Each Party shall promptly notify the other Party in writing on receipt by that first mentioned Party or any of its respective Affiliates (including in respect of Purchaser, any of the Purchased Entities) or its or their Representatives of any notice or communication of any pending or threatened federal, provincial, state, local or foreign Tax audits, examinations, claims, assessments, appeals or other proceedings (a “**Tax Claim**”) relating to Taxes of any of the Purchased Entities in respect of which that first mentioned Party is entitled to seek, is seeking or intends to seek, indemnification from that other Party pursuant to Section 11.1.

(b) After Closing, Vendor or its Affiliates shall be entitled to assume control of any Tax Claim, and to exclusively represent the interests of the Purchased Entities in and with respect to any Tax Claim, relating to taxation years or periods ending before the Closing Date or relating to Taxes in respect of which Vendor or its Affiliates have an indemnification obligation under Section 11.1(a)(i) or (ii), and Vendor or an Affiliate of Vendor may employ counsel of its own choice, at its own expense, for that purpose so long as Vendor or its Affiliates provide Purchaser with a notice to such effect within thirty (30) days of being notified of such Tax Claim pursuant to Section 11.7(a). Vendor shall be liable for all professional fees and expenses incurred in respect of each such Tax Claim.

If Vendor or an Affiliate of Vendor assumes control of a Tax Claim, Vendor or that Affiliate of Vendor shall keep Purchaser reasonably apprised with respect to the status of such Tax Claim.

From and after the Closing, neither Purchaser nor a Purchased Entity nor any of their Affiliates or Representatives shall settle or compromise, or agree to settle or compromise, any Tax Claim which may be the subject of indemnification by Vendor under Section 11.1(a)(i) or (ii).

(c) After Closing, Vendor shall, in its sole discretion, be permitted to assume control or have an Affiliate of Vendor assume control, on behalf of the applicable Purchased Entity, of any and all objections and appeals identified in Schedule 4.25(d), and any and all other objections, appeals or other matters and proceedings that relate to or in respect of a taxation year or period of any of the Purchased Entities in respect of which Vendor has an indemnification obligation under Section 11.1(a)(i) or (ii), including the filing of objections and appeals on behalf of the applicable Purchased Entity. For clarity, all refunds or credits received by a Purchased Entity as a result of a successful objection or appeal (including as a result of litigation relating thereto) shall be for the account of Vendor in accordance with Section 11.4.

(d) If the settlement of any Tax Claim in respect of which Vendor or an Affiliate of Vendor has assumed control, might reasonably be expected to materially and adversely affect Purchaser or the Purchased Entities in respect of any taxation year ending on or after the Closing Date, then Vendor or its Affiliate shall only settle such Tax Claim with the consent of Purchaser, such consent not to be unreasonably withheld, conditioned or delayed.

(e) Purchaser or a Purchased Entity shall have the right to control any Tax Claim relating to the Purchased Entities relating to taxation years or periods ending at or before the Closing Date if Vendor does not assume control of such Tax Claim in accordance with Section 11.7(b) and pay all Taxes that are the subject of the Tax Claim. If Vendor does not pay the Taxes assessed, Vendor shall be liable for and shall reimburse Purchaser for all professional fees and reasonable expenses incurred by Purchaser or any of the Purchased Entities in connection with such Tax Claim.

(f) With respect to any Tax Claim in respect of which the applicable Tax authority asserts that an amount is payable in respect of which, or in respect of part of which, Vendor has an indemnification obligation under Section 11.1(a)(i) or (ii) and which Vendor or an Affiliate of Vendor pays, on or before the date such Tax Claim is required to be paid to the applicable Tax authority, the amount thereof in respect of which Vendor has an indemnification obligation under Section 11.1(a)(i) or (ii), all costs and expenses incurred by Purchaser in contesting such Tax Claim, and all interest payable or receivable, in respect of the period after the date of payment shall be entirely for the account of Purchaser.

11.8 Assistance and Cooperation

(a) After Closing, Vendor and Purchaser shall (and shall cause their respective Affiliates to):

(i) cooperate in a timely manner in preparing for any audits of, or disputes with Tax authorities regarding, any Tax Returns of any of the Purchased Entities,

(ii) provide timely notice to the other in writing of any pending or threatened Tax audits or assessments of any of the Purchased Entities for taxation years or other periods in respect of which the other may have an indemnification obligation under this Article 11,

(iii) within 30 days of the receipt of a written request therefor, furnish the other with copies of all correspondence received from any Tax authority in connection with any Tax audit or information request with respect to any taxation years or other periods in respect of which the other may have an indemnification obligation under this Article 11,

(iv) Purchaser will, after Purchaser has been afforded a reasonable opportunity to review such documents, grant a limited power of attorney to an individual designated by Vendor who will timely sign and deliver such certificates or forms as may be necessary or appropriate to establish an exemption from (or otherwise reduce), or file Tax Returns or other reports with respect to, Taxes described in Section 11.1, and

(v) use reasonable efforts to properly retain and maintain accounting and Tax records and information, consistent with Tax authority guidelines, to the extent such records and information relate to any of the Purchased Entities or any of the Entity Assets or other properties of the Business carried on by the Purchased Entities until the expiration of the applicable period outlined in Section 6.4(a)(i) to Section 6.4(a)(iv), as applicable, and promptly notify the other Party prior to destruction of any such records or information and provide the other Party a reasonable opportunity to make and retain copies of any such records or information, provided however, nothing herein shall require Vendor or any of its Affiliates to deliver Tax Records or other Excluded Books and Records to Purchaser or any of its Affiliates (including the Purchased Entities).

(b) Purchaser shall, and shall cause the Purchased Entities to, grant to Vendor or its Affiliates access at all reasonable times to all Books and Records delivered to Purchaser pursuant to Section 9.15 and all other records, information and documents (including without limitation work papers and correspondence with Tax authorities) relating to any of the Purchased Entities, the Entity Assets or the other properties of the Business carried on by the Purchased Entities, and shall afford Vendor (or its designees) the right (at Vendor’s expense) to take extracts therefrom and to make copies thereof, and to make same available to relevant Tax authorities, to the extent reasonably necessary to permit Vendor (or its designees) to prepare the Tax Returns of Vendor or any of its Affiliates or the Tax Returns of the Purchased Entities for which Vendor is responsible, to conduct negotiations with Tax authorities and to investigate, prosecute or defend any Claims, including Tax Claims and including Claims arising between the Parties under Article 9.

(c) Vendor shall grant to Purchaser access at all reasonable times to all Tax Records, (including without limitation work papers and correspondence with Tax authorities) relating to any of the Purchased Entities, the Entity Assets or the other properties of the Business carried on by the Purchased Entities, and shall afford Purchaser (or its designees) the right to take extracts therefrom and to make copies thereof, and to make same available to relevant Tax authorities, to the extent reasonably necessary to permit Purchaser (or its designees) to prepare the Tax Returns of Purchaser or any of its Affiliates or the Tax Returns of the Purchased Entities for which Purchaser is responsible, to conduct negotiations with Tax authorities and to investigate, prosecute or defend any Claims, including Tax Claims and including Claims arising between the Parties under Article 9 and to meet its financial reporting obligations in preparing audited financial statements in accordance with U.S. GAAP.

(d) Purchaser shall, and shall cause the Purchased Entities to, timely provide to Vendor or an Affiliate of Vendor designated by it, powers of attorney or similar authorizations reasonably required to carry out the intent and purpose of this Article 11.

11.9 Coordination with Other Provisions

(a) If any provision of this Article 11, conflicts with any provision of Articles 6 or 10, the provisions of this Article 11 shall govern, provided however, the payment obligations and other obligations under this Article 11, including indemnity payments under Section

11.1, payment of Tax refunds to Vendor and reimbursements for expenses, shall not be subject to Section 6.1.

(b) In this Article 11 references to Purchaser and the Purchased Entities shall include any successors and predecessors thereto, whether by merger, amalgamation, dissolution, reorganization or otherwise.

11.10 Tax Changes Post-Closing

Purchaser agrees and confirms that, notwithstanding any provisions of this Agreement, Vendor shall not be liable for any inaccuracy in or breach of the representations and warranties contained in Section 4.25 to the extent that any change made after the Closing Time:

(a) in any accounting or taxation policies of a Purchased Entity,

(b) in any federal, state or provincial Tax rates, or

(c) in a Tax statute or regulation that is effective prior to its announcement,

causes Vendor to be liable for breach of such representations and warranties.

11.11 Certain Closing Day Transactions

(a) If any of the Purchased Entities is party to an amalgamation (as defined in subsection 87(1) of the Tax Act) that occurs on the Closing Date and after the Closing Time on the Closing Date, Purchaser and the Purchased Entities shall take such steps as are necessary to ensure that such amalgamation shall be specified to occur at a specific time on the Closing Date, and that time shall not be earlier than 12:01 a.m. on the Closing Date, and

(b) if control of any of the Purchased Entities is acquired on the Closing Date and after the Closing Time on the Closing Date (other than pursuant to the Purchase), such that the Purchased Entity has a deemed year end pursuant to subsection 249(4) of the Tax Act, Purchaser and the Purchased Entities shall take such steps as are necessary to ensure that an election pursuant to subsection 256(9) of the Tax Act is filed in respect of the transaction giving rise to that acquisition of control.

ARTICLE 12
TERMINATION AND CLOSING

12.1 Termination

This Agreement may be terminated at any time before Closing:

(a) by mutual written consent of Vendor and Purchaser,

(b) subject to Section 12.2, by Purchaser, if any of Purchaser’s Conditions shall not have been fulfilled by the Closing Time (or such earlier time if so required herein) or shall have become incapable of fulfillment by the Outside Date (or such earlier time if so required herein) other than as a result of Purchaser’s breach of this Agreement, and shall not have been waived by Purchaser,

(c) by Vendor, if at any time the representation and warranty contained in Section 5.9 is or becomes untrue, it being agreed that this Section 12.1(c) shall constitute Vendor’s sole termination remedy with respect to a breach by Vendor of Section 5.9,

(d) by Vendor, if any of Vendor’s Conditions shall not have been fulfilled by the Closing Time (or such earlier time if so required herein) or shall have become incapable of fulfillment by the Outside Date (or such earlier time if so required herein) other than as a result of Vendor’s breach of this Agreement, and shall not have been waived by Vendor,

(e) by either Vendor or Purchaser, if the Regulatory Condition has not been satisfied on or before the Regulatory Condition Deadline, provided that, the right to terminate this Agreement under this Section 12.1(e) shall not be available to a Party whose failure to fulfill any obligation under this Agreement has caused or resulted in the Regulatory Condition not being satisfied on or before the Regulatory Condition Deadline, and

(f) by either Vendor or Purchaser, if Closing does not occur on or before the Outside Date; provided that, the right to terminate this Agreement under this Section 12.1(f) shall not be available to a Party whose failure to fulfill any obligation under this Agreement has caused or resulted in Closing not occurring by the Outside Date.

(g) Prior to exercising their respective rights to terminate pursuant to Section 12.1(b) or (d), Vendor and Purchaser agree to provide notice of the applicable breach to the other Party and allow 10 Business Days thereafter during which:

(i) the Party in breach shall have the right to cure any defaults giving right to such termination, and

(ii) the Parties will negotiate in good faith in and effort to avert a termination and complete the Purchase.

During such 10 Business Day period, neither Party shall exercise any other available termination rights hereunder.

12.2 Walk Right Threshold

(a) Purchaser may not terminate this Agreement under Section 12.1(b) or otherwise refuse to complete the Purchase on the basis of any representations or warranties made by Vendor in this Agreement being incorrect or inaccurate, or any covenants of Vendor being breached, or any Damage or Destruction Event, unless, as a result thereof, the aggregate amount of all Losses to the Purchaser or the Purchased Entities of all uncured Material Claims and all Damage or Destruction Events exceeds U.S.$300,000,000 in the aggregate determined as at the Closing Time, provided that, notwithstanding the foregoing, Purchaser may not terminate this Agreement under Section 12.1(b) or

otherwise refuse to complete the Purchase on the basis of any representations or warranties made by Vendor in Section 4.25 and Section 4.26 being incorrect or inaccurate. For clarity, this Section 12.2 shall apply to a determination as to whether the Purchaser’s Conditions in Sections 7.1, 7.2 and 7.11 have been satisfied or fulfilled.

(b) For the purposes of Section 12.2(a), including for purposes of:

(i) determining whether a representation and warranty is incorrect or inaccurate or a covenant of Vendor has been breached, and

(ii) calculating the amount of any Losses related thereto,

Vendor's representations and warranties shall be read and applied without regard to, and shall be deemed not to be qualified by, any reference in the text thereof to "materiality", "material", "materially", "material respects", "Material Adverse Effect" or similar materiality qualifiers set forth herein (other than the word "Material" in the expressions "Material Claim", "Material Consent", "Material Contract" or "Material Facility", as part of the defined term); provided, however, that the term "material respects" or the word "material", as applicable, shall continue to apply as a modifier with respect to the required content of the Schedules contemplated by Section 4.23(h) and Section 4.24(a).

(c) For purposes of Section 12.2(a) and Section 7.11, any Loss attributable to a Damage or Destruction Event shall be calculated net of any proceeds of insurance paid or payable to any Purchased Entity or any Affiliate thereof in respect of such Damage or Destruction Event or any other monetary recovery or right to monetary recovery by or of any Purchased Entity in respect of such Damage or Destruction Event, including the proceeds paid or payable to any Purchased Entity or any Affiliate thereof in respect of any expropriation proceeding.

12.3 Notice of Termination

Subject to Section 12.4, termination of this Agreement by Vendor or Purchaser pursuant to Section 12.1 shall be effective upon deemed receipt of written notice thereof given by the Party terminating this Agreement to the other Party whereupon this Agreement and the transactions contemplated by this Agreement (including the Parties' obligation to consummate the Purchase) shall be terminated without further action by either Party.

12.4 [*****]

(a) [*****].

(b) [*****].

(c) [*****].

(d) [*****].

(e) [*****].

[*****] indicates redacted terms for which confidential treatment has been requested from the SEC. The redacted information has been filed separately with the SEC.

(f) [*****].

(g) [*****].

[*****] indicates redacted terms for which confidential treatment has been requested from the SEC. The redacted information has been filed separately with the SEC.

12.5 Deposit

(a) [*****].

(b) Upon termination of this Agreement, the Deposit, together with all interest accrued thereon less any amount in respect of withholding taxes, shall be forthwith paid by Vendor to Purchaser unless [*****].

12.6 Remedies Exclusive; Specific Performance

(a) If Closing occurs, the indemnities provided in this Agreement constitute the sole and exclusive remedy of Purchaser or Vendor, respectively, against the other Party in respect of a breach of any representation, warranty, covenant or agreement of that other Party under this Agreement or otherwise in respect of the transactions contemplated hereby.

(b) [*****].

(c) Notwithstanding the foregoing or the termination of this Agreement, Section 9.18, Section 9.19, Section 9.20, this Article 12, Section 13.4 and Section 13.14 shall survive the termination of this Agreement. Nothing herein shall impair the right of a Party to seek specific performance or other equitable relief to enforce Section 9.18, this Article 12 or Section 13.14 or any remedy (including damages and equitable relief) in the event of breach of Section 12.4 or breach of any of the Confidentiality Agreements.

(d) In the event that the Agreement is terminated at any time before Closing by a Party pursuant to Section 12.1, Purchaser shall, as soon as reasonably practical in the circumstances, return to Vendor the books, records and other documents received by Purchaser pursuant to Section 9.15.

12.7 Exception to Confidentiality Agreement

Notwithstanding the January 28, 2011 Confidentiality Agreement, but subject to compliance with the Confidentiality Agreements other than the January 28, 2011 Confidentiality Agreement, Purchaser may disclose Evaluation Material, as defined in the January 28, 2011 Confidentiality Agreement, to its financial, legal, taxation and other advisors and to current and prospective underwriters, securityholders, and lenders and other debtholders and their advisors in connection with financings by Purchaser and its Affiliates and in connection with the Purchase including the financing thereof, provided that any such Persons are required to comply with the January 28, 2011 Confidentiality Agreement as if they were Recipient’s Representatives, as contemplated in Section 1(ix) thereof.

12.8 Confidential Information

If this Agreement is terminated under Section 12.1:

[*****] indicates redacted terms for which confidential treatment has been requested from the SEC. The redacted information has been filed separately with the SEC.

(a) Purchaser and its Related Parties shall return to Vendor all Confidential Information pertaining to Vendor or any of the Purchased Entities received from or on behalf of Vendor, whether so obtained before or after the execution hereof, and

(b) all such Confidential Information shall be treated in accordance with the terms and conditions of the Confidentiality Agreements, which shall remain in full force and effect notwithstanding the termination of this Agreement.

ARTICLE 13
GENERAL

13.1 Waiver

Any waiver given hereunder must be in writing and signed by the Party giving such waiver. No waiver of any condition or other provision or breach thereof, in whole or in part, shall constitute a waiver of any other condition or provision or breach thereof (whether or not similar) nor shall such waiver constitute a continuing waiver.

13.2 Public Notices

(a) Vendor and Purchaser shall keep, and shall cause their Affiliates to keep, the terms of this Agreement confidential, except to the extent disclosure is: (i) permitted by the terms of this Section 13.2 or the January 28, 2011 Confidentiality Agreement, (ii) subject to Section 13.2(b), required by Applicable Law, Environmental Law or Governmental Authority, including the rules of any securities regulatory authority, listing authority or stock exchange with which the disclosing Person or any Affiliate of the disclosing Person is bound to comply, or (iii) for financial reporting purposes or as otherwise provided herein; except that the Parties and their Affiliates may disclose those terms hereof to their respective Representatives as necessary in connection with the ordinary conduct of their respective businesses so long as those Persons agree to keep the terms of this Agreement confidential (it being agreed that the applicable disclosing Party or Affiliate thereof shall make such Representatives aware of the confidentiality obligations under this Section 13.2(a) and shall be responsible for any breach thereof by such Representatives).

(b) Notwithstanding Section 13.2(a), without the consent of the other Party (which consent shall not be unreasonably withheld, conditioned or delayed), neither Vendor nor Purchaser will make, or permit its respective Affiliates to make, any press release or other public announcement respecting this Agreement without the consent of the other Party, unless:

(i) the Person desiring to make the press release or other public announcement is advised by its counsel that the release or announcement is required to comply with Applicable Law, Environmental Law or Governmental Authority, including the rules of any securities regulatory authority, listing authority or stock exchange with which the disclosing Person or any Affiliate of the disclosing Person is bound to comply, and

(ii) that press release or other public announcement does not disclose more information regarding this Agreement or the subject matter hereof than is required to comply with Applicable Law, Environmental Law or Governmental Authority, including the rules of any securities regulatory authority, listing authority or stock exchange with which the disclosing Person or any Affiliate of the disclosing Person is bound to comply,

provided that, prior to any such disclosure, the non-disclosing Party or its Affiliate is first provided with a copy of such proposed disclosure and a reasonable opportunity to comment on such disclosure.

(c) Notwithstanding the foregoing, but subject to Section 13.2(d), advance consent shall not be required in connection with, and nothing contained herein or in the January 28, 2011 Confidentiality Agreements shall prevent a Party or its Affiliates from:

(i) furnishing any information to any Governmental Authority:

(A) if required by Applicable Law, Environmental Law or Governmental Authority, including the rules of a securities regulatory authority, listing authority or stock exchange, or

(B) if required to obtain the Required Approvals, or

(ii) making a general announcement (without disclosing any commercially sensitive information (including the Base Price and the Purchase Price) concerning the transactions contemplated hereby that has not otherwise previously been disclosed pursuant to the terms hereof or the January 28, 2011 Confidentiality Agreement) regarding the Purchase to its employees (including the Entity Employees), or

(iii) making or hosting, as applicable, customary investor and analyst presentations, meetings and conference calls.

(d) If either Party or its Affiliates proposes to make any such disclosure as described in Sections 13.2(c), the applicable disclosing Party shall, to the extent reasonably possible, provide the non-disclosing Party with a draft of the applicable press release or other document containing the disclosure (including the script of any conference calls) at least two (2) Business Days before its release, filing or delivery to enable the other Party to review that draft and advise of any comments it may have with respect thereto. The Person proposing to make such disclosures will not unreasonably refuse to incorporate the requested changes of Vendor or Purchaser, as the case may be, to the applicable press release or other document.

13.3 Assignment

Neither this Agreement nor any benefits, rights or obligations under this Agreement shall be assignable by Vendor, without the prior express written consent of Purchaser, or by Purchaser, without the prior express written consent of Vendor, which consents may be arbitrarily withheld.

Notwithstanding the foregoing prohibition on assignment, Purchaser may assign all of its benefits, rights and obligations under this Agreement to an Affiliate of Purchaser that is a resident of Canada for purposes of the Tax Act (but not if that assignment would extend the time for, or render less certain, the completion of the Purchase) provided that such assignment shall not release Purchaser from any of its obligations under this Agreement and provided further that such Affiliate enters into an agreement with Vendor, Purchaser and Purchaser Guarantor satisfactory to Vendor, pursuant to which that Affiliate expressly assumes all of Purchaser's obligations under this Agreement and Purchaser Guarantor agrees to guarantee those obligations as provided in the Guarantee, *mutatis mutandis*, and, if that assignment occurs before the Closing, Purchaser and such Affiliate covenant with Vendor that such Affiliate will remain an Affiliate of Purchaser until Closing. Subject to the foregoing, this Agreement shall inure to the benefit of, be enforceable by and be binding on the Parties and their respective successors (including any successor by reason of amalgamation, merger, wind up or dissolution of any Party) and permitted assigns.

Notwithstanding the foregoing prohibition on assignment, Vendor may assign any of its rights hereunder to any of its Affiliates (but not if that assignment would extend the time for, or render less certain, the completion of the Purchase) on written notice thereof to Purchaser.

Any obligation of a Party hereto may be discharged by an Affiliate of such Party without, however, derogating in any way from the liability of such Party to discharge such obligation.

13.4 Notices

Any notice or other writing required or permitted to be given under this Agreement or for the purposes of this Agreement (in this Section 13.4 referred to as a "**Notice**") shall be in writing and shall be sufficiently given if delivered or transmitted by facsimile to:

(a) in the case of a Notice to Vendor:

BP Canada Energy Group ULC
240 4 Avenue SW
PO Box 200
Calgary, Alberta T2P 2H8
Attention: Brian G. Selinger
Fax: (403) 233-1188

with a copy to:

Fraser Milner Casgrain LLP

15th Floor
Bankers Court
850 — 2nd Street SW
Calgary, Alberta
Attention: Mike Hurst
Fax: (403) 268-3100

(b) in the case of a Notice to Purchaser:

Plains Midstream Canada ULC
607 — 8th Avenue S.W.
Calgary, Alberta
T2P 0A7
Attention: Michael Callihoo
Fax: (403) 233-0399

with a copy to:

Plains All American Pipeline, L.P.
Suite 1600 333 Clay Street
Houston, TX 77002-4622
U.S.A.
Attention: Richard K. McGee
Fax: (713) 646-4216

with a copy to:

Bennett Jones LLP
4500 Bankers Hall East
8500 2nd Street SW
Calgary, Alberta
T2P 4K7
Attention: Donald E. Greenfield
Fax: (403) 265-7219

or at such other address or fax number as the Person to whom that Notice is to be given shall have last notified the Person giving the same in the manner provided in this Section 13.4. Any Notice will be deemed to have been validly and effectively given (i) if personally delivered, on the date of that delivery if that date is a Business Day and that delivery was made before 4:30 p.m. (Calgary time), and otherwise on the next Business Day; or (ii) if transmitted by facsimile or similar means of recorded communication, on the Business Day following the date of transmission if receipt of the transmission has been confirmed back.

13.5 Further Assurances

Each Party shall do all acts and things and execute and deliver all such further documents or instruments as are reasonably necessary to carry out the provisions and intent of this Agreement, whether before or after the Closing.

13.6 No Recourse

Notwithstanding anything that may be expressed or implied in this Agreement, except as provided in Section 13.3, and except for equitable remedies to enjoin any breach of the confidentiality obligations herein contained, each Party covenants, agrees and acknowledges that no recourse under this Agreement shall be had against, and no personal liability whatsoever shall attach to, be imposed on or otherwise be incurred by, any current, former or future shareholder (except pursuant to the Vendor Parent Guarantee or the Purchaser Parent

Guarantee), director, officer or employee of either Party or any of the Affiliates of either Party, whether by any legal or equitable proceeding, or by virtue of any Applicable Law or Environmental Law, provided that, all obligations of each Party shall be binding upon any successor of such Party, whether by agreement, amalgamation, liquidation, operation of law or otherwise.

13.7 Time of the Essence

Time shall be of the essence of this Agreement.

13.8 Amendment

This Agreement may not be amended or modified except by an express instrument in writing signed on behalf of each of the Parties.

13.9 Invalidity

In the event that any one or more provisions contained in this Agreement or in any other instrument referred to herein shall, for any reason, be held to be invalid, illegal or unenforceable in any respect, such invalidity, illegality or enforceability shall not affect any other provision of this Agreement or any other such instrument.

13.10 Counterparts

This Agreement may be executed by the Parties in separate counterparts, each of which when so executed and delivered shall be an original, and all such counterparts shall together constitute one and the same instrument and a signed counterpart delivered by facsimile or other electronic means shall be considered as valid as an original counterpart.

13.11 Enforcement

The Parties agree that irreparable damage would occur in the event that any of the provisions of this Agreement were not performed in accordance with their specific terms, or were otherwise breached. It is accordingly agreed that the Parties shall be entitled to an injunction or injunctions to prevent breaches of this Agreement and to enforce specifically the terms and provisions of this Agreement.

13.12 No Third-Party Beneficiaries

This Agreement, other than as provided in Sections 13.3 and 13.6 and in the provisions of Article 10 relating to indemnification, is not intended to confer on any Person, other than the Parties, any rights or remedies.

13.13 Expenses

Except as otherwise provided herein, each of the Parties, Purchaser Guarantor and Vendor Guarantor shall pay their respective legal, accounting and other professional advisory and all other fees, costs and expenses (including fees of investment bankers) incurred in connection with the Purchase and the negotiation, preparation, execution and delivery of this Agreement

and all documents and instruments executed pursuant to this Agreement and all other costs and expenses incurred in connection therewith, provided, however, notwithstanding the foregoing, any such expenses of Vendor may be paid by the Purchased Entities.

13.14 Removal of Name

(a) After Closing, but subject to Sections 13.14(b) and (c) with respect to the matters provided therein, Purchaser and its Affiliates, including the Purchased Entities, shall not be entitled to use and shall not use any service marks, trade names, trade dress, logos, designs or other indicia of origin of Vendor or any of its Affiliates (including the Purchased Entities), including (i) the words or letters "BP", "British Petroleum", "Amoco", "Dome", "Vastar", "ARCO", "Atlantic Richfield Company", "The Standard Oil Company" or "Standard" or any such items that include such words or letters, (ii) the Standard/Amoco oval or torch and oval design, (iii) the phrase "BP Oil", (iv) the BP shield or the BP Group Helios logo, (v) the ARCO Spark, and (vi) any variations or derivations of any of the foregoing (collectively, the "**Prohibited Names and Marks**").

(b) In addition, as soon as reasonably practicable, but in any event by the earlier of (i) 60 days following Closing and (ii) the date required by Applicable Law or Environmental Law, Purchaser shall and shall cause each of the Purchased Entities to:

(i) remove, obliterate or replace, as appropriate, all signs, billboards, containers, drums, advertisements or other media containing any such Prohibited Names and Marks located on or appurtenant to any portion of the Entity Assets,

(ii) cause the destruction, disposal or replacement of stationery, business cards, purchase orders and similar assets containing any such Prohibited Names and Marks, and

(iii) make all requisite filings with, and provide requisite notices to, the appropriate Governmental Authorities to place title or other evidence of operation or ownership in a name other than the Prohibited Names and Marks.

(c) Within five (5) Business Days of Closing, Purchaser shall cause each of the Purchased Entities to change its corporate name, by the filing of all necessary documents with such public officials as may be necessary, so as to remove from their corporate names all such Prohibited Names and Marks.

IN WITNESS WHEREOF the Parties have duly executed this Agreement as of the date and year first written above.

AMOCO CANADA INTERNATIONAL HOLDINGS B.V.
BP MANAGEMENT INTERNATIONAL B.V.

By: /s/ Hendrik Muilerman
Authorized Signing Officer

By: /s/ Marijke Paaijmans
Authorized Signing Officer

PLAINS MIDSTREAM CANADA ULC

By: /s/ Ralph Cross
Authorized Signing Officer

Exhibit 10.45

Directors' Compensation Summary

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.

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 each have outstanding a grant of 10,000 units (vesting 2,500 units per year). Messrs. 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.

EXHIBIT 12.1

STATEMENT OF COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(in millions)

	Year Ended December 31,				
	2011	**2010**	**2009**	**2008**	**2007**
EARNINGS [1]					
Pre-tax income from continuing operations before noncontrolling interest and income from equity investees	$ 1,026	$ 510	$ 572	$ 430	$ 350
add: Fixed charges	328	321	283	264	233
add: Distributed income of equity investees	23	9	7	10	2
add: Amortization of capitalized interest	2	1	1	1	—
less: Capitalized interest	(25)	(16)	(12)	(17)	(14)
Total Earnings	$ 1,354	$ 825	$ 851	$ 688	$ 571
FIXED CHARGES [1]					
Interest expensed and capitalized [2]	$ 298	$ 281	$ 247	$ 233	$ 220
Amortization of debt expense	10	8	7	4	3
Portion of rent expense related to interest (33.33%)	20	32	29	27	10
Total Fixed Charges	$ 328	$ 321	$ 283	$ 264	$ 233
RATIO OF EARNINGS TO FIXED CHARGES [3]	4.13x	2.57x	3.00x	2.60x	2.45x

[1] For purposes of computing the ratio of earnings to fixed charges, “earnings” consists of pre-tax income from continuing operations before income from equity investees plus fixed charges (excluding capitalized interest), distributed income of equity investees and amortization of capitalized interest. “Fixed charges” represents interest incurred (whether expensed or capitalized), amortization of debt expense (including discounts and premiums relating to indebtedness) and the portion of rental expense on operating leases deemed to be the equivalent of interest.

[2] Includes interest costs attributable to borrowings for hedged inventory purchases of $20 million, $17 million, $11 million, $21 million and $44 million for the years ended December 31, 2011, 2010, 2009, 2008 and 2007, respectively.

[3] Ratios may not recalculate due to rounding.

Exhibit 21.1

SUBSIDIARIES OF
PLAINS ALL AMERICAN PIPELINE, L.P.

(*As of 12/31/11*)

Subsidiary	Jurisdiction of Organization
5D Marketing LLC	Colorado
Aurora Pipeline Company Ltd.	Canada
Centerpoint Access LLC	Texas
Durham Transport LLC	Texas
Lazybay Operating LLC	Texas
Legacy Line LLC	Texas
Lone Star Trucking, LLC	California
Mountain Ridge Resources LLC	Colorado
PAA Finance Corp.	Delaware
PAA Luxembourg S.a.r.l.	Luxembourg
PAA Midstream LLC	Delaware
PAA Vulcan Gas Storage, LLC	Delaware
Pacific Energy GP LP	Delaware
Pacific Energy Group LLC	Delaware
Pacific Energy Management LLC	Delaware
Pacific L.A. Marine Terminal LLC	Delaware
Pacific Pipeline System LLC	Delaware
PACONO1 LLC	Delaware
PACONO2 LLC	Delaware
PICSCO LLC	Delaware
Plains All American Emergency Relief Fund, Inc.	Delaware
Plains Eagle Ford Pipeline LLC	Delaware
Plains Gas Solutions, LLC	Texas
Plains LPG Services GP LLC	Delaware
Plains LPG Services, LP	Delaware
Plains Marketing — North Dakota Inc.	Delaware
Plains Marketing Bondholder, LLC	Delaware
Plains Marketing Canada LLC	Delaware
Plains Marketing GP Inc.	Delaware
Plains Marketing, L.P.	Texas
Plains Midstream Canada ULC	Alberta
Plains Midstream Luxembourg S.a.r.l.	Luxembourg
Plains Pipeline — North Dakota LLC	Wyoming
Plains Pipeline, L.P.	Texas
Plains Products Terminals LLC	Delaware
Plains South Texas Gathering LLC	Texas
Plains Southcap LLC	Delaware
Plains West Coast Terminals LLC	Delaware
PMC (Nova Scotia) Company	Nova Scotia
PMDSE, Inc.	Mississippi
Rancho LPG Holdings LLC	Delaware
Rocky Mountain Pipeline System LLC	Delaware
SLC Pipeline LLC	Delaware
Southcap Pipe Line Company	Delaware
VirKel Backhoe Services LLLP	Colorado
PNGS GP LLC	Delaware
PAA Natural Gas Storage, L.P.	Delaware
PAA Natural Gas Storage, LLC	Delaware
BGS Kimball Gas Storage, LLC	Delaware
Bluewater Gas Storage, LLC	Delaware
Bluewater Natural Gas Holding, LLC	Delaware
PAA Natural Gas Canada ULC	Alberta
Pine Prairie Energy Center, LLC	Delaware
PNG Finance Corp.	Delaware
PNG Marketing, LLC	Delaware
PPEC Bondholder, LLC	Delaware
SG Resources Mississippi, L.L.C.	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-138888, 333-155673, 333-162475, 333-162476 and 333-162477) and on Form S-8 (No. 333-91141, 333-54118, 333-74920, 333-122806 and 333-141185) of Plains All American Pipeline, L.P. of our report dated February 27, 2012 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Houston, Texas
February 27, 2012

EXHIBIT 31.1

CERTIFICATIONS

I, Greg L. Armstrong, certify that:

1. I have reviewed this annual report on Form 10-K of Plains All American Pipeline, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2012

/s/ Greg L. Armstrong
Greg L. Armstrong
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATIONS

I, Al Swanson, certify that:

1. I have reviewed this annual report on Form 10-K of Plains All American Pipeline, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2012

/s/ Al Swanson
Al Swanson
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. 1350

I, Greg L. Armstrong, Chief Executive Officer of Plains All American Pipeline, L.P. (the “Company”), hereby certify that:

(i) the accompanying report on Form 10-K for the period ended December 31, 2011 and filed with the Securities and Exchange Commission on the date hereof (the “Report”) by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Greg L. Armstrong
Name: Greg L. Armstrong
Date: February 27, 2012

EXHIBIT 32.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. 1350

I, Al Swanson, Chief Financial Officer of Plains All American Pipeline, L.P. (the “Company”), hereby certify that:

(i) the accompanying report on Form 10-K for the period ended December 31, 2011 and filed with the Securities and Exchange Commission on the date hereof (the “Report”) by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Al Swanson
Name: Al Swanson
Date: February 27, 2012