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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2010

or

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

Commission file number 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

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

(713) 646-4100

(Registrant s telephone number, including area code)

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes 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. o

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 $7.0 billion on June 30, 2010, based on $58.70 per unit, the closing price of the Common Units as reported on the New York Stock Exchange on such date.

As of February 22, 2011, there were 141,199,175 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

NONE

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

FORM 10-K 2010 ANNUAL REPORT

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FORWARD-LOOKING STATEMENTS

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

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

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- 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;
- future developments and circumstances at the time distributions are declared;
- 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, refined products and liquefied petroleum gas and other natural gas related petroleum products.

Other factors described herein, or 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, refined products and liquefied petroleum gas and other natural gas-related petroleum products. We refer to liquefied petroleum gas and other natural gas-related petroleum products collectively as LPG. Through our general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P. (NYSE: PNG), we also engage in the acquisition, development and operation of natural gas storage facilities. Our business activities are conducted through three segments: Transportation, Facilities and Supply and Logistics.

Organizational History

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

Partnership Structure and Management

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

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The chart below depicts the current structure and ownership of Plains All American Pipeline, L.P. and certain subsidiaries as of February 22, 2011.

Partnership Structure

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(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 million limited partner units, representing approximately 7% 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.

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

Business Strategy

Our principal business strategy is to provide competitive and efficient midstream transportation, terminalling, storage 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, LPG and natural gas storage in the United States and Canada by combining the strategic location and capabilities of our transportation, terminalling and storage assets with our extensive supply, logistics and distribution expertise.

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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;

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

- utilizing our assets along the Gulf, West and East Coasts along with our terminals and leased assets to optimize our presence in the waterborne importation of foreign crude oil;

- 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;

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

- using our terminalling and storage 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.

We intend to utilize PNG as the primary vehicle through which we will participate in the natural gas storage business. We believe PNG s natural gas storage assets are also well-positioned to benefit from long-term industry trends and opportunities. PNG s growth strategies are to develop and implement internal growth projects and to selectively pursue strategic and accretive acquisitions of natural gas storage projects and facilities. Through execution of such growth strategies, we intend to expand the scale and scope of our natural gas storage business. We may also prudently and economically leverage our asset base, knowledge base and skill sets to participate in other energy-related businesses that have characteristics and opportunities similar to, or that otherwise complement, our existing activities.

Financial Strategy

Targeted Credit Profile

We believe that a major factor in our continued success is our ability to maintain a competitive cost of capital and access to the capital markets. 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 50%;

- an adjusted 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 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 supply and logistics activities that involve the simultaneous purchase and forward sale of crude oil, refined products, LPG and natural gas. The crude oil, refined products, LPG and natural gas purchased in these transactions are hedged. We do not consider the working capital borrowings associated with this activity to be part of our long-term capital structure. These borrowings

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are self-liquidating as they are repaid with sales proceeds. We also incur short-term debt for New York Mercantile Exchange (NYMEX) and IntercontinentalExchange (ICE) margin requirements.

In order for us to maintain our targeted credit profile and achieve growth through internal growth projects and acquisitions, we intend to fund 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 crude oil supply and logistics activities are balanced.* We believe the variety of activities executed within our supply and logistics segment provides us with a balance that generally affords us the flexibility to maintain a base level of margin in a variety of crude oil market conditions and in certain circumstances, to realize incremental margin during volatile market conditions.

- *We have the evaluation, integration and engineering skill sets and the financial flexibility to continue to pursue acquisition and expansion opportunities.* Over the past thirteen years, we have completed and integrated approximately 65 acquisitions with an aggregate purchase price of approximately $6.8 billion. We have also implemented internal expansion capital projects totaling approximately $2.5 billion. In addition, we believe we have resources to finance future strategic expansion and acquisition opportunities. As of December 31, 2010, we had a working capital surplus of approximately $166 million and approximately $841 million 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 26 years industry experience, and an average of 15 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.

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Acquisitions

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

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	
SG Resources Mississippi, LLC (SG Resources)	Feb-2011	Southern Pines Energy Center (Southern Pines) natural gas storage facility	$	746(1)
Nexen Holdings U.S.A. Inc. (Nexen)	Dec-2010	Crude oil gathering and transportation assets in North Dakota and Montana	$	229
PAA Natural Gas Storage, LLC	Sep-2009	Remaining 50% interest in PNGS	$	215(2)
Rainbow Pipe Line Company, Ltd	May-2008	Crude oil gathering and transportation assets in Alberta, Canada	$	687
Pacific Energy Partners LP (Pacific)	Nov-2006	Merger of Pacific Energy Partners with and into the Partnership	$	2,456
Andrews Petroleum and Lone Star Trucking (Andrews)	Apr-2006	Isomerization, fractionation, marketing and transportation services	$	220

(1) Acquisition made by our subsidiary PNG.

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

Southern Pines Acquisition. On February 9, 2011, PNG acquired 100% of the equity interests in SG Resources (the Southern Pines Acquisition), which entity owns the Southern Pines Energy Center natural gas storage facility, for total consideration of approximately $746 million, subject to certain post-closing adjustments.

Southern Pines is a Federal Energy Regulatory Commission (FERC)-regulated, high-performance, salt-cavern natural gas storage facility located in Greene County, Mississippi. The facility s current permits allow for 40 billion cubic feet (Bcf) of working capacity from four storage caverns. The facility commenced service in 2008 and three caverns have been placed into service, which are serving over 17 Bcf of customer contracts. These caverns are being expanded over time to their permitted capacity of 10 Bcf each. The fourth cavern is currently being drilled and is anticipated to be placed into service in the third quarter of 2012. The facility has the capacity for further expansion beyond 40 Bcf, if warranted by market demand and subject to receipt of required additional permits. Southern Pines is connected directly or indirectly to eight major natural gas pipelines servicing the Gulf Coast, Northeast, Mid-Atlantic and Southeastern U.S. markets.

See *Recent Developments* for discussion of transactions completed in conjunction with this acquisition.

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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 business lines and enable us to leverage our asset base, knowledge base and skill sets. Such acquisition efforts may involve participation by us in processes that have been made public and involve a number of potential buyers, commonly referred to as auction processes, as well as situations in which we believe we are the only party or one of a limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets which, if acquired, could have a material effect on our financial condition and results of operations. Even after we have reached agreement on a purchase price with a potential seller, confirmatory due diligence or negotiations regarding other terms of the acquisition can cause discussions to be terminated. Accordingly, we typically do not announce a transaction until after we have executed a definitive acquisition agreement. Although we expect the acquisitions we make to be accretive in the long term, we can provide no assurance that our expectations will ultimately be realized. See Item 1A. *Risk Factors* Risks Related to Our Business *If we do not make acquisitions 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*.

Recent Developments

During early 2011, we completed several noteworthy business transactions such as the completion of the Southern Pines acquisition for total consideration of approximately $746 million, subject to certain post-closing adjustments, as discussed within the preceding *Acquisitions* section. In conjunction with this acquisition, PNG completed a private placement of 17.4 million 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. As a result of these transactions, our aggregate ownership interest in PNG decreased from approximately 77% to approximately 64%.

In addition, during early 2011, we also expanded our liquidity through various transactions such as completion of a $600 million senior notes offering and by entering into a $500 million 364-day senior unsecured credit facility. In addition, we redeemed our 7.75% senior notes that were maturing in 2012 for approximately $222 million.

Global Petroleum Market Overview

The United States comprises less than 5% of the world s population, generates 11% of the world s petroleum production, and consumes 22% of the world s petroleum production. The following table sets forth projected world supply and demand for petroleum products (including crude oil, natural gas liquids (NGL) and other liquid petroleum products) and is derived from the Energy Information Administration s (EIA) Annual Energy Outlook 2011 Early Release (see EIA website at *www.eia.doe.gov*).

			Projected	
	2010 (1)	**2011**	**2012**	**2015**
		(In millions of barrels per day)		

Supply				
OECD (2)				
U.S.	9.6	9.6	9.8	10.3
Other	11.6	11.3	11.1	10.5
Total OECD	21.2	20.9	20.9	20.8
Organization of the Petroleum Exporting Countries	34.8	35.6	36.5	37.2
Other	30.4	30.9	31.5	32.4
Total World Production	86.4	87.4	88.9	90.4

			Projected	
	2010 (1)	**2011**	**2012**	**2015**
		(In millions of barrels per day)		
Demand				
OECD				
U.S.	19.1	19.1	20.0	20.5
Other	26.6	26.6	26.5	26.0
Total OECD	45.7	45.7	46.5	46.5
Other	40.7	41.7	42.4	43.9
Total World Consumption	86.4	87.4	88.9	90.4
U.S. Production as % of World Production	11%	11%	11%	11%
U.S. Consumption as % of World Consumption	22%	22%	22%	23%
Net U.S. Consumption	(9.5)	(9.5)	(10.2)	(10.2)

(1) The 2010 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.

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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 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, such as specific gravity (generally referred to as light or heavy), sulfur content (generally referred to as sweet or sour) and metals content, which 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. For the 20-year time period beginning in 1985 through 2004, U.S. refinery demand for crude oil increased 29% from 12.0 million barrels per day to approximately 15.5 million barrels per day. U.S. refinery demand for crude oil demand remained effectively flat from 2005 through 2007 at around 15.5 million barrels per day, after which refinery demand decreased to average approximately 14.6 million barrels per day for the 12 months ended October 2010. Of this amount, only 5.5 million barrels per day was produced domestically. Accordingly, approximately 62% of the crude oil used by U.S. domestic refineries is imported. This imbalance represents a multi-year trend, with foreign imports of crude oil tripling over a 23-year period, from 3.2 million barrels per day in 1985 to approximately 10.1 million barrels per day from 2005-2007. Concurrent with decreased refinery demand and recent increases in domestic production, foreign crude imports have slowed to 9.1 million barrels per day for the 12 months ended October 2010. Reduced demand for petroleum products from end users 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. Since 2000, ethanol production has grown from approximately 100,000 barrels per day to approximately 840,000 barrels per day for the 12 months ended October 2010. Growth in ethanol and other renewable fuel production is expected to continue. The EIA is currently forecasting a continued gradual decline in foreign crude imports from current levels, which is attributable to increased domestic production, increased refined product imports and increase supply from other liquid products, including ethanol and biodiesel. The table below shows the overall domestic petroleum consumption projected out to 2015 and is derived from recent information published by the EIA (see EIA website at *www.eia.doe.gov*). The amounts in the 2010 column are based on the twelve months from November 2009 to October 2010.

	Actual		**Projected**	
	2010	**2011**	**2012**	**2015**
		(In millions of barrels per day)		
Supply				
Domestic Crude Oil Production	5.5	5.3	5.4	5.7
Net Imports - Crude Oil	9.1	9.2	9.0	8.8

Crude Oil Input to Domestic Refineries	14.6	14.5	14.4	14.5
Net Product Imports	0.5	0.5	1.1	1.2
Supply from Renewable Sources	0.8	0.9	1.0	1.1
Other - (NGL Production, Refinery Processing Gain)	3.2	3.2	3.5	3.7
Total Domestic Petroleum Consumption	19.1	19.1	20.0	20.5

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 2010 and is derived from information published by the EIA (see EIA website at *www.eia.doe.gov*) (in millions of barrels per day).

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Petroleum Administration Defense District	Regional Supply	Refinery Demand	Supply Shortfall
PADD I (East Coast)	0.0	1.1	(1.1)
PADD II (Midwest)	0.7	3.3	(2.6)
PADD III (South)	3.2	7.3	(4.1)
PADD IV (Rockies)	0.4	0.6	(0.2)
PADD V (West Coast)	1.2	2.3	(1.1)
Total U.S.	5.5	14.6	(9.1)

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

From 1985 until 2004, crude oil production in PADD II has declined from approximately 1.1 million barrels per day to approximately 440,000 barrels per day. Over this same time period, refinery demand has increased from approximately 2.7 million barrels per day in 1985 to 3.3 million barrels per day in 2004. As a result, the volume of crude oil transported into PADD II has increased approximately 75% in absolute terms or 3.0% annually from 1.7 million barrels per day to 3.0 million barrels per day. This aggregate shortfall was principally supplied by direct imports from Canada to the north and from the Gulf Coast area and the Cushing Interchange to the south.

Starting in 2005, PADD II production began to grow and as of early 2011 is currently estimated to be over 700,000 barrels per day, driven mainly by increased production from the Bakken oil formation in North Dakota. This production growth is in an isolated part of the country, which has created its own infrastructure challenges and opportunities. Both the incremental Canadian oil production growth and the PADD II growth have generally targeted the Cushing & Patoka crude oil hubs. This has resulted in a decline in volumes moved from the Gulf Coast area into PADD II, but an increase in demand for storage at Cushing and Patoka.

Volatility in various aspects of the crude oil market including absolute price, market structure, 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 trend narrowing the gap between supply and demand;
- Temporal increases in the gap related to supply response following price spikes and declines in the rate of demand growth due to worldwide economic slowdown;
- Regional supply and demand imbalances;
- Political instability in critical producing nations;

- Policy decisions made by various governments around the world attempting to navigate energy challenges; and

- Significant fluctuations in absolute price as well as grade and location differentials.

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

Refined Products Market Overview

Once crude oil is transported to a refinery, it is processed into different petroleum products. These refined products fall into three major categories: 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.

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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 and, to a lesser extent, weather conditions. According to the EIA, consumption of refined products in the United States has risen from approximately 15.7 million barrels per day in 1985 to a peak in 2005 of 20.8 million barrels, yielding an average annual increase of approximately 1.5%. Due to the economic weakness of the last several years, refined product demand decreased to 18.8 million barrels per day in 2009, or an approximate 10% decrease over peak demand levels. Given this decreased demand for refined products and resulting excess refining capacity, a number of U.S. refineries reduced output and, in some cases, indefinitely closed. Demand for refined products has resumed growth in 2010 with consumption reaching approximately 19.1 million barrels per day for the twelve months ended October 2010. The EIA is currently forecasting growth in refined product demand for the next several years. The level of future demand growth will be influenced by the slope of the economic recovery and absolute prices. We believe that this projected demand growth will be met primarily by the increase in mandated alternative fuels, increased utilization of existing refining capacity as well as increased imports of refined products, the combination of which we believe will continue to 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.

LPG Products Market Overview

LPGs are hydrogen-based gases that are derived from crude oil refining and natural gas processing and include propane, butane and isobutane. These gases liquefy at moderate pressures thus allowing transportation and storage opportunities. LPG is produced domestically or imported into the U.S. from Canada and other parts of the world. Individual LPG products have varying uses. For example, propane is used in domestic applications (home heating and cooking), industrial applications, agricultural applications (crop drying) and as an automotive fuel. Normal butane is used as a petrochemical feedstock, as a blendstock for motor gasoline, and to derive isobutane through isomerization. Isobutane is principally used in refinery alkylation to enhance the octane content of motor gasoline or in the production of isooctane or other octane additives. Certain LPGs are also used as diluents in the transportation of heavy oil, particularly in Canada.

The LPG market is driven by:

- seasonal shifts in weather;
- seasonal changes in gasoline specifications affecting demand for butane;
- alternating needs of refineries to store and blend LPG;
- petro-chemical demand;
- diluent requirements for Canadian heavy oil; and
- inefficiencies caused by regional supply and demand imbalances.

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

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Natural Gas 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 by allowing natural gas to be injected into, withdrawn from or warehoused in such storage facilities as dictated by market conditions.

The long-term demand for storage services in the United States is driven primarily by the long-term 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. In general and on a long term basis, to the extent the overall demand for natural gas increases and such growth includes higher demand from seasonal or weather-sensitive end-users (such as gas-fired power generators and residential and commercial consumers), demand for natural gas storage services should also grow. In addition, 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, should increase the need for and the value of storage services. On a short term basis, storage demand and values are also significantly influenced by operational imbalances, near term seasonal spreads, shorter term spreads and basis differentials.

Natural Gas Demand. During the period from 2001 through 2010, domestic natural gas consumption has grown, albeit unevenly, driven primarily by growth in the seasonal and weather-sensitive electric power generation and commercial sectors, offset by declines in the residential and industrial sectors.

Natural Gas Supply. For a number of years during the last decade, domestic natural gas production was relatively flat and has failed to keep pace with domestic consumption. Over the past few years, however, domestic natural gas production has been growing. This trend reversal is primarily due to increases in production from developing shale resource plays. According to EIA data, domestic production of natural gas increased by an average of approximately 3.7% per annum during the four-year period beginning January 1, 2007 through December 31, 2010. By comparison, EIA data also indicates that 2009 production from shale gas wells was approximately 3.1 trillion cubic feet (Tcf), representing an approximate 142% increase over 2007 levels. At the time of this report, 2010 production estimates by component (i.e. shale gas) were not available from EIA.

In addition to the emergence of domestic shale plays as a significant supply source, over the past several years, the U.S. has developed significant infrastructure for the import of liquefied natural gas (LNG). Total LNG import capacity of U.S. infrastructure has increased to approximately 14 Bcf per day; however, because LNG suppliers have been able to obtain more favorable prices in global markets outside of the U.S., LNG imports into the U.S. have decreased from a peak of 2.1 Bcf a day in 2007 to less than 1.2 Bcf per day in 2009 and 2010, per EIA and other published daily data sources.

Market Balance and Volatility. The seasonality of natural gas 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. Natural gas storage (and to a lesser extent imported natural gas from Canada and LNG supplies) 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 as a warehouse for gas production in excess of daily demand during low demand periods. This seasonal consumption pattern is a major driver of demand for gas storage and the price difference, or spread, between the summer and winter season provides a proxy for the fundamental value of storage.

During most of the past decade, this strong seasonal trend has produced seasonal spreads that have generally moved within a range of approximately $0.50-$4.75 per MMBtu, with the high end of that range occurring during the 2006-2007 timeframe. However, during the past six months, seasonal spreads fell to as low as $0.43, their lowest point since 2004. In addition, lower short-term spreads and basis differentials have reduced overall market volatility, which negatively impacts storage demand and value. 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 two years, (ii) increased natural gas supplies due to production from shale resources, (iii) lower basis differentials due to expansion of natural gas transportation infrastructure in the U.S. over the last five years, and (iv) abnormal seasonal weather patterns resulting in decreased seasonal price spreads.

Supply of Storage Capacity. Another important factor in determining the value of storage is whether there is a surplus or shortfall of storage capacity relative to the overall demand for storage services in a given market area. In general, on a relative basis, storage values will be lower in markets that are oversupplied with storage than in markets where storage capacity is in short supply. The extent to which markets are oversupplied or undersupplied will fluctuate based on capacity additions and in response to significant variations in natural gas supply and demand.

While it is difficult to predict when, and how much, new capacity will be added to the market in the next few years, we believe that certain of the supply and demand factors contributing to the current softness in the storage market (i.e., robust supply levels, lower natural gas demand levels and reduced price volatility) 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 and crude oil, refined product and LPG transportation corridors in the United States and Canada.

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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 Butte, Frontier, Settoon Towing and White Cliffs, in which we own noncontrolling interests.

As of December 31, 2010, 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;
- 25 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;
- 56 trucks and 352 trailers; and
- 65 transport and storage barges and 39 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, 2010, grouped by geographic location:

Region / Pipeline and Gathering Systems (1)	**System Miles**	**2010 Average Net Barrels per Day (2) (in thousands)**
Southwest US		
Basin	519	378
Permian Basin Area Systems	3,085	371
Other	406	141
Southwest US Subtotal	**4,010**	**890**
Western US		
All American	138	39

Line 63/Line 2000	426	109
Other	148	83
Western US Subtotal	**712**	**231**
US Rocky Mountain		
Salt Lake City Area Systems	708	135
Other	3,857	280
US Rocky Mountain Subtotal	**4,565**	**415**
US Gulf Coast		
Capline(3)	631	223
Other	924	322
US Gulf Coast Subtotal	**1,555**	**545**
Central US Subtotal	**2,462**	**350**
Domestic Total	**13,304**	**2,431**
Canada		
Rangeland	1,214	52
Rainbow	594	187
Manito	559	61
Other	633	158
Canada Total	**3,000**	**458**
Grand Total	**16,304**	**2,889**

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

(2) Represents average volume for the entire year of 2010.

(3) Non-operated pipeline.

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Southwest US

Basin Pipeline System. We own an approximate 87% undivided joint interest in and act as operator of the Basin Pipeline system. The Basin system is a primary route for transporting crude oil from the Permian Basin (in west Texas and southern New Mexico) to Cushing, Oklahoma, for further delivery to Mid-Continent and Midwest refining centers. The Basin system is a 519-mile mainline, telescoping crude oil system with a 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 378,000 barrels per day (attributable to our interest) during 2010.

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.

We recently approved an expansion project on the Basin system to increase pipeline capacity on crude oil movements from Colorado City, Texas to Cushing, Oklahoma to approximately 450,000 barrels per day. The project is expected to be completed in the first quarter of 2012.

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 2010, combined throughput on the Permian Basin area systems totaled an average of approximately 371,000 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 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.

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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,				
	2010	2009	2008	2007	2006
Average daily volumes received from:					
Point Arguello (at Gaviota)	6	6	7	8	9
Santa Ynez (at Las Flores)	33	34	38	38	40
Total	39	40	45	46	49

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 26 storage tanks with 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 2010, combined throughput on Line 63 totaled an average of approximately 51,000 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 130,000 barrels per day. During 2010, throughput on Line 2000 averaged approximately 58,000 barrels per day.

US Rocky Mountain

Salt Lake City Area Systems. We operate the Salt Lake City Area systems, in which we own between 75% and 100% interests. 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 708 miles of pipelines and approximately 1 million barrels of storage capacity. The Salt Lake City Area systems have a combined throughput capacity of approximately 120,000 barrels per day to Salt Lake City and 20,000 barrels per day to Ft. Laramie. For 2010, throughput on the Salt Lake City Area Systems in total averaged approximately 135,000 barrels per day.

US Gulf Coast

Capline Pipeline System. The Capline Pipeline system is a 631-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. In October 2010, we purchased an additional undivided 11% interest in the Capline Pipeline System which increased our aggregate undivided joint interest to approximately 54%. We also own a 100% interest in 720,000 barrels of tankage located at Patoka, Illinois.

The Capline Pipeline system is one of the primary transportation routes for crude oil shipped into the Midwestern U.S., serving approximately 3 million barrels of refining capacity in PADD II. 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, with its two active docks capable of handling approximately 600,000-barrel tankers as well as access to

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the Louisiana Offshore Oil Port and our St. James terminal, it is a key transporter of sweet and light sour foreign crude to PADD II. Total designed operating capacity is approximately 1 million barrels per day of crude oil. In connection with the purchase of our additional undivided interest in the system, our attributable interest in this operating capacity has increased from approximately 470,000 barrels per day to approximately 600,000 barrels per day. Throughput on our interest averaged approximately 223,000 barrels per day during 2010.

Canada

Rangeland System. We own a 100% interest in the Rangeland system, which includes the Mid Alberta Pipeline (MAPL) and the Rangeland Pipeline. The Rangeland system consists of a 554 mile, 8-inch to16-inch mainline pipeline and 660 miles of 3-inch to 8-inch gathering pipelines. Rangeland transports butane, condensate, light sweet crude and light sour crude either north to Edmonton, Alberta by MAPL or south to the U.S./Canadian border near Cutbank, Montana, where it connects to our Western Corridor system. On April 1, 2010, we successfully reversed MAPL allowing for flow from Rangeland s Sundre, Alberta terminal directly to Edmonton, Alberta. During 2010, Plains built and commissioned 80,000 barrels of tankage bringing our storage capability at Edmonton to 400,000 barrels. Total average throughput during 2010 on the Rangeland system was approximately 52,000 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. During 2009, we added a heavy oil truck terminal at Nipisi, Alberta to provide producers with additional access to Rainbow. The system has a throughput capacity of approximately 220,000 barrels per day and transported approximately 187,000 barrels per day during 2010.

Manito. We own a 100% interest in the Manito heavy oil system. This 559-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 339 miles of pipeline, the mainline segment originates at Dulwich and terminates at Kerrobert, Saskatchewan. The Bodo/Cactus Lake pipeline is 136 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. At the end of 2009, Plains made the necessary changes to the Kerrobert terminal to expand the flexibility whereby we can now both receive and deliver heavy crude from and to the Enbridge pipeline system. For 2010, approximately 61,000 barrels per day of crude oil were transported on the Manito system.

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, as well as LPG fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements. Revenues generated in this segment include (i) storage fees that are generated when we lease storage capacity, (ii) terminalling fees, or throughput fees, that are generated when we receive crude oil, refined products, LPG or natural gas from one connecting pipeline and redeliver the applicable product to another connecting carrier, (iii) hub service fees for the movement of natural gas across our header systems, and (iv) fees from LPG fractionation and isomerization services.

As of December 31, 2010, we owned, operated and employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 59 million barrels of crude oil and refined products capacity primarily at our terminalling and storage locations;
- approximately 6 million barrels of LPG storage capacity;
- approximately 50 Bcf of natural gas storage working capacity;
- approximately 11 Bcf of base gas in storage facilities owned by us; and
- a fractionation plant in Canada with a processing capacity of 4,400 barrels per day, and a fractionation and isomerization facility in California with an aggregate processing capacity of 26,000 barrels per day.

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As of December 31, 2010, we were in the process of constructing approximately 4 million barrels of additional above-ground crude oil and refined product terminalling and storage capacities and an additional 18 Bcf of high-deliverability salt-cavern natural gas storage capacity.

The following is a tabular presentation of our active facilities segment storage assets in the United States and Canada as of December 31, 2010, grouped by product type:

Facility	**Capacity (in millions of barrels, except where noted)**
Crude Oil and Refined Products	
Cushing	14
Kerrobert	1
LA Basin	8
Martinez and Richmond	5
Mobile and Ten Mile	3
Patoka	5
Philadelphia Area	4
St. James	7
Other	12
Subtotal	**59**
LPG	
Bumstead	2
Tirzah	1
Other	3
Subtotal	**6**
Natural Gas	
Pine Prairie	24 Bcf
Bluewater	26 Bcf
Subtotal	50 Bcf

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

Major Facilities Assets

Crude Oil and Refined Products

Cushing Terminal. Our Cushing, Oklahoma Terminal (the Cushing Terminal) is located at the Cushing Interchange, one of the largest wet-barrel trading hubs in the U.S. and the delivery point for crude oil futures contracts traded on the NYMEX. The Cushing Terminal has been designated by the NYMEX as an approved delivery location for crude oil delivered under the NYMEX light sweet crude oil futures contract. As the NYMEX delivery point and a cash market hub, the Cushing Interchange serves as a primary source of refinery feedstock for the Midwest refiners and plays an integral role in establishing and maintaining markets for many varieties of foreign and domestic crude oil. Our Cushing Terminal was constructed in 1993, with an initial tankage capacity of 2 million barrels, to capitalize on the crude oil supply and demand imbalance in the Midwest. The facility 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 increased the capacity of the Cushing Terminal to a total of approximately 14 million barrels. During the first quarter of 2010, we placed into service four 570,000-barrel tanks, and during the fourth quarter of 2010 completed construction on four additional 270,000-barrel tanks. See Crude Oil Storage Facilities Under Construction and Under Development below for discussion of ongoing expansion activities at this facility.

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.

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L.A. Basin. We own five crude oil and refined product storage facilities in the Los Angeles area with a total of 8 million barrels of useable storage capacity and a distribution pipeline system of approximately 70 miles of pipeline in the Los Angeles Basin. Approximately 7 million barrels of the storage capacity are used for commercial service and 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 through a 36-inch pipeline connecting the two facilities, of which 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. During 2010, we completed Phase II and III storage capacity expansion projects adding 600,000 barrels and 800,000 barrels, respectively. Patoka is a growing regional hub with access to domestic and foreign crude oil volumes moving north on the Capline system as well as Canadian barrels moving south. See Crude Oil Storage Facilities Under Construction and Under Development below for discussion of ongoing expansion activities at this facility.

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 also includes a manifold and header system that allows for receipts and deliveries with connecting pipelines at their maximum operating capacity. Over the past two years, we completed the construction of a marine dock that is able to receive both barges and tankers, as well as Phase II of our expansion project adding approximately 900,000 barrels of storage capacity.

Crude Oil Storage Facilities Under Construction and Under Development

Cushing Terminal & Mid-Continent Area. Late in 2010, we began construction on additional crude oil tankage at our Cushing Terminal at an estimated cost of $85 million. The project, which consists of three phases, includes adding a new pipeline interconnect and approximately 4 million barrels of storage capacity through the construction of sixteen 270,000 barrel tanks. Construction of Phases IX, X and XI are supported by long-term customer commitments and are expected to be placed in service by the end of 2011.

Patoka Terminal. Early in 2011, we approved construction of Phase IV at our Patoka Terminal. This project will include the construction of two 300,000 barrel crude oil tanks and will increase the total storage capacity at Patoka to approximately 5 million barrels. This new tankage is expected to be completed in the first quarter of 2012 at an approximate cost of $18 million.

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 project Environmental Impact Report (EIR) 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. 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. Currently, future costs to develop this project are estimated to be in the $450 to $550 million range. We currently have approximately $45 million of capitalized project costs on our balance sheet as of December 31, 2010. We expect to be in a position in 2011 to determine whether or not we will move forward with the Pier 400 project.

LPG Storage Facilities

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

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 late in 2011 at a total cost of approximately $19 million.

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 and is connected to the Dixie Pipeline System (a third-party system) via our 62-mile pipeline.

LPG Processing

Shafter. Our Shafter facility located near Bakersfield, California provides isomerization and fractionation services to producers and customers of NGL. The primary assets consist of 200,000 barrels of NGL storage and a processing facility with butane isomerization capacity of 14,000 barrels per day and NGL fractionation capacity of 12,000 barrels per day. During the first quarter of 2011, we approved our Shafter Expansion Project. This project will include the construction of a 15-mile LPG 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 third quarter of 2012 at an anticipated investment of approximately $50 million. We expect to invest approximately $30 million during 2011.

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Natural Gas Storage Facilities

Pine Prairie. As a strategically located, high-deliverability storage facility, Pine Prairie has 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 hub.

Additionally, in January 2011, the CME Group, which is the owner of the NYMEX, announced the introduction of three new natural gas futures contracts for physical delivery at Pine Prairie. The contracts began trading in February 2011 on the NYMEX floor and electronically through CME Globex and will be available for clearing services through CME ClearPort.

Pine Prairie s pipeline header system, which includes an aggregate of 74 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 has a total current working gas storage capacity of 24 Bcf in three caverns, and planned expansions that will increase Pine Prairie s total capacity to 42 Bcf by mid-2012 and 45 Bcf by mid-2016. Subject to market demand, project execution, sufficient pipeline capacity, available financing and receipt of future permits, we have the property rights and operational capacity to expand our Pine Prairie facility significantly beyond our current permitted capacity of 48 Bcf. Taking these considerations into account and with certain infrastructure modifications, we currently estimate that Pine Prairie could support in excess of 15 salt caverns and an aggregate storage capacity of over 150 Bcf.

In October 2010, we filed an application for a permit from the FERC to expand Pine Prairie s working capacity up to 80 Bcf. The incremental 32 Bcf would be comprised of expanding four existing caverns by an aggregate 8 Bcf through low-cost fill and dewater operations and adding two additional caverns of 12 Bcf each, increasing the total caverns at Pine Prairie to seven caverns.

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, and primarily services seasonal storage needs throughout 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 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 has total working gas storage capacity of approximately 26 Bcf in two depleted reservoirs and we expect to increase Bluewater s working gas capacity by 2 Bcf ratably over a 9 to 10-year period in connection with an ongoing liquids removal project. 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.

Recent Acquisition

During February 2011, we closed the Southern Pines Acquisition. See Acquisitions and *Recent Developments* above for further information regarding the Southern Pines Acquisition and related transactions.

Supply and Logistics Segment

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

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

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

- the purchase of refined products and LPG from producers, refiners and other marketers;

- the resale or exchange of crude oil, refined products and LPG at various points along the distribution chain to refiners or other resellers to maximize profits; and

- the transportation of crude oil, refined products and LPG on trucks, barges, railcars, pipelines and ocean-going vessels to our terminals and third-party terminals.

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 providing upside potential associated with opportunities inherent in volatile market conditions. These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies to provide a 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, 2010, 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;

- 530 trucks and 607 trailers; and

- 1,395 railcars.

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.

The following table shows the average daily volume of our supply and logistics activities for the year ended December 31, 2010 (in thousands of barrels per day):

	Volumes
Crude oil lease gathering purchases	620
LPG sales	96
Waterborne foreign crude oil imported	68
Supply & Logistics activities total	784

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. The majority of these contracts, however, range in term from thirty-days to one year. We utilize our truck fleet and gathering pipelines as well as third-party pipelines, trucks and barges to transport the crude oil to market. In addition, we purchase foreign crude oil. Under these contracts we may purchase crude oil upon delivery in the U.S. or we may purchase crude oil in foreign locations and transport it on third-party tankers.

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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 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 and LPG is purchased in bulk when we believe additional opportunities exist to realize margins further downstream in the crude oil or LPG distribution chain. The opportunities to earn additional margins vary over time with changing market conditions. Accordingly, the margins associated with our bulk purchases will fluctuate from period to period.

Crude Oil and LPG Sales. The 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 and a familiarity with a number of factors including grades of crude oil, individual refinery demand for specific grades of crude oil, area market price structures, location of customers, various modes and availability of transportation facilities and timing and costs (including storage) involved in delivering crude oil and LPG to the appropriate customer.

We sell our crude oil to major integrated oil companies, independent refiners and other resellers in various types of sale and exchange transactions. 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 four years. The majority of these contracts are at market price and have terms ranging from one month 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, LPG and refined products for resale and require significant extensions of credit by our suppliers. In order to assure our ability to perform our obligations under the purchase agreements, various credit arrangements are negotiated with our suppliers. These arrangements include open lines of credit and, to a lesser extent, standby letters of credit issued under our senior unsecured revolving credit facility.

When we sell crude oil, LPG, natural gas and refined products, we must determine the amount, if any, of the line of credit to be extended to any given customer. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures.

Because our typical crude oil sales transactions can involve tens of thousands of barrels of crude oil, the risk of nonpayment and nonperformance by customers is a major consideration in our business. We believe our sales are made to creditworthy entities or entities with adequate credit support. Generally, sales of crude oil are settled within 30 days of the month of delivery, and pipeline, transportation and terminalling services 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, natural gas and refined products; however, because our sales are typically in relatively small amounts to individual customers, we do not believe that these transactions pose a material concentration of credit risk. Typically, we enter into annual contracts to sell LPG on a forward basis, as well as to sell LPG on a current basis to local distributors and retailers. In certain cases our LPG customers prepay for their purchases, in

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amounts ranging from approximately $1 per barrel to 100% of their contracted amounts. Generally, sales of LPG and refined products settle within 10 days of the invoice date.

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. More recently, crude oil prices traded as low as $33 per barrel in early 2009, before increasing to a range of $85 to $95 per barrel in February 2011.

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 75% 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 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 line 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.

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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 of whether there is value in doing so. Conversely, trading related risks (the risks involved in trading in the hopes of generating an increased return) are not inherent in 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, futures contracts or other 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 15 to our Consolidated Financial Statements.

Customers

Marathon Oil Corporation and its affiliates accounted for 14% of our revenues for each of the three years ended December 31, 2010, 2009 and 2008. ConocoPhillips Company accounted for 10%, 12% and 12% of our revenues for the years ended December 31, 2010, 2009 and 2008, respectively. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2010. 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.

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 have existing storage facilities connected to their systems that compete with some of our facilities.

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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. 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 injunctive remedies, the effect of which would subject us to operational requirements and constraints that would not apply to our competitors. See Item 3. Legal Proceedings.

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 (the 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.

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. Costs associated with the inspection, testing and correction of identified anomalies were approximately $31 million in 2010, $25 million in 2009 and $23 million in 2008. Based on currently available information, our preliminary estimate for 2011 is that we will incur approximately $12 million in operational expenditures and approximately $25 million in capital expenditures associated with our pipeline integrity management program. The acquisitions we have completed over the last several years have included pipeline assets of varying ages and maintenance and operational histories. Accordingly, we will continue to focus on pipeline integrity management as a primary operational emphasis. 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.

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In 2010, Congress began hearings on the reauthorization of the PIPES Act, which expired in September 2010. Congress did not complete the reauthorization process in 2010, so it will be deferred to 2011 for the new 112th Congress to consider. However, a lapse has no real effect on PHMSA regulation or programs as the pipeline safety program will continue at its previous funding levels. As part of the reauthorization process, on October 18, 2010, PHMSA issued an Advance Notice of Proposed Rulemaking (ANPRM). Within the ANPRM, PHMSA stated that it is considering whether changes are needed to the regulations covering hazardous liquid pipelines and is seeking public comment on six specific topic areas. The six topics include, (1) the scope of the pipeline safety regulations and existing regulatory exceptions, (2) the criteria for designation as a High Consequence Area (HCA), (3) leak detection and Emergency Flow Restricting Devices, (4) valve spacing, (5) repair criteria for non-HCA areas, and (6) Stress Corrosion Cracking. At this point we cannot predict what new requirements, if any, may come about as a result of reauthorization of the PIPES Act and PHMSA s ANPRM. Significant additional operating expenses could be incurred if new or more stringently interpreted pipeline safety requirements are implemented.

Effective July 2008, PHMSA amended its pipeline safety regulations to extend protection to designated unusually sensitive areas or USAs that could be damaged by failure of certain rural onshore hazardous liquid gathering lines or low-stress pipelines. These USAs include locations containing sole-source drinking water, endangered species, or other ecological resources. Operators of rural onshore hazardous liquid gathering lines located within a defined buffer area around a USA must comply with safety requirements to address threats of corrosion and third-party damage to their lines by developing a damage prevention program, complying with specified corrosion control requirements, and monitoring and mitigating conditions that could lead to internal corrosion. The amended rules narrow the regulatory exception for rural onshore low-stress hazardous liquid pipelines by extending existing safety regulations (including integrity management requirements) to certain low-stress pipelines within a defined buffer area around a USA. In June 2010, PHMSA proposed to extend the amended requirements to all remaining rural low-stress hazardous liquid pipelines that were not covered by the initial rulemaking. We have less than 300 miles of pipeline subject to the amended rules and do not expect compliance to have a material effect on our operating expenses.

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 must be written by August 1, 2011 and implemented by February 1, 2013. In November 2010, PHMSA proposed to expedite program implementation for most of the rule s requirements to August 2011. We have already incorporated many of the new rule s requirements into our control room operations and we anticipate completing the revisions to our management plan and fully implementing the new provisions prior to the deadlines established in this new rule or prior to the proposed expedited deadline.

We have an internal review process in which we examine the condition and operating history of certain pipelines and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, in addition to potential cost increases related to unanticipated regulatory changes or injunctive remedies resulting from 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. Initial compliance, subject to an applicable waiver or stay, was required in May 2009. Costs associated with this program were approximately $25 million, $22 million and $41 million in 2010, 2009 and 2008, respectively. For 2011, we have budgeted approximately $26 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.

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 $23 million in 2010, $20 million in 2009 and $8 million in 2008 on these types of costs. Our preliminary estimate for 2011 is approximately $28 million.

Although we believe that our pipeline operations are in substantial compliance with currently applicable regulatory requirements, we cannot predict the potential costs associated with additional, future regulation. Asset acquisitions are an integral part of our business strategy. As we acquire additional assets, we may be required to incur additional costs in order to ensure that the acquired assets comply with the regulatory standards in the U.S. and Canada.

Occupational Safety and Health

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

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

Solid Waste

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

Hazardous Substances

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

Environmental Remediation

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

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

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In conjunction with our acquisitions, we typically make an assessment of potential environmental exposure and determine whether to negotiate an indemnity, what the terms of any indemnity should be and whether to obtain environmental risk insurance, if available. These contractual indemnifications typically are subject to specific monetary requirements that must be satisfied before indemnification will apply, and have term and total dollar limits. For instance, in connection with the purchase of former Texas New Mexico (TNM) pipeline assets from Link Energy LLC (Link) in 2004, we identified a number of environmental liabilities for which we received a purchase price reduction from Link and recorded a total environmental reserve of $20 million, of which we agreed in an arrangement with TNM to bear the first $11 million in costs of pre-May 1999 environmental issues. TNM also agreed to pay all costs in excess of $20 million (excluding certain deductibles). TNM s obligations are guaranteed by Shell Oil Products (SOP). As of December 31, 2010, we had incurred approximately $19 million of remediation costs associated with these sites, while SOP s share has been approximately $8 million.

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

Air Emissions

Our operations are subject to the U.S. Clean Air Act (Clean Air Act) and comparable state and provincial laws. Under these laws, permits may be required before construction can commence on a new 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. For example, EPA has recently proposed a significant tightening of the national ambient air quality standards for ozone which, if adopted, could require significant reductions in emissions of volatile organic compounds and nitrogen oxides in regions of the U.S. that have not previously been subject to the most stringent emissions limitations.

Climate Change Initiatives

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 United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol. The Kyoto Protocol requires Canada to reduce its emissions of GHG to 6% below 1990 levels by 2012.

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 tonnes per year (kt/y) of CO_2 equivalent 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 operations of Plains Midstream Canada (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.

Draft regulations to reduce GHGs from the electricity sector are expected to be published in *Canada Gazette* early in 2011 and final regulations published later this year. This will allow sufficient time for consultations and outreach with industry and other stakeholders. Regulations are scheduled to come into effect on July 1, 2015. 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.

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The United States is not participating in the Kyoto Protocol, and, as a result of the November 2010 elections, it appears unlikely that the U.S. Congress will adopt significant climate change legislation within the next two years. However, numerous states already have begun implementing either GHG reporting requirements or actual measures to reduce GHG emissions through mechanisms such as regional cap-and-trade programs. There has also been considerable regulatory activity at the federal level even in the absence of new legislation. Some of the more notable federal actions are:

- In October 2009, EPA issued a rule requiring annual reporting of GHG emissions from stationary facilities.

- On December 15, 2009, EPA published a formal endangerment finding that sets the groundwork for GHG s to be regulated pollutants under the Clean Air Act.

- In May 2010, EPA and the National Highway Transportation Safety Administration (NHTSA) jointly issued rules setting GHG standards for light-duty vehicles.

- In June 2010, EPA issued a rule establishing major source thresholds and permitting requirements for large emitters of GHG s.

- In December 2010, EPA and NHTSA announced they would be proposing GHG standards for medium and heavy-duty vehicles.

- In January 2011, EPA began requiring state environmental agencies to specify GHG emission control requirements in permits for new or substantially modified sources of significant GHG emissions.

We anticipate that a small number of our facilities (less than ten) will be subject to the GHG reporting requirements in 2011 and 2012. These include facilities with combustion GHG emissions and potential fugitive emissions above the reporting thresholds, and we expect to report entity-wide GHG emissions on the basis of finished fuels that we import from outside of the U.S. 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.

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.

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

State Regulation. Our intrastate pipeline transportation activities are subject to various state laws and regulations, as well as orders of state regulatory bodies, including the 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. See Note 12 to our Consolidated Financial Statements. The TRRC is subject to a sunset condition. If the Texas Legislature does not continue the TRRC, the TRRC will be abolished effective September 1, 2011 and will begin a one-year wind-down process. The Sunset Advisory Commission has recommended certain organizational changes be made to the TRRC. We cannot tell what, if any, changes will be made to the TRRC as a result of the pending regular session or any called sessions of the Texas Legislature in 2011, but we do not believe that any such changes would affect our business in a way that would be materially different from the way such changes would affect our competitors.

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. The current methodology (the producer price index for finished goods plus an adjustment factor of 1.3 percent) will remain in place through June 30, 2011. Effective July 1, 2011, the index for the next five year period will be the producer price index for finished goods plus an adjustment factor of 2.65 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, agreement with an unaffiliated shipper, 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, driver operations, log book maintenance, truck manifest preparations, safety placard placement on the trucks and trailer vehicles, drug and alcohol testing, operation and equipment safety, and 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.

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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.

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

Interstate Regulation. Our natural gas storage facilities are classified as natural-gas companies under the Natural Gas Act of 1938 (NGA), and are therefore subject to regulation by the FERC. The NGA requires that tariff rates for gas storage facilities be just and reasonable and non-discriminatory. The FERC has authority to regulate rates and charges for natural gas transported and stored in U.S. interstate commerce or sold by a natural gas company in interstate commerce for resale. The FERC has granted our natural gas storage facilities market-based rate authority. Market-based rate authorization allows us to negotiate rates with individual customers based on market demand, which Pine Prairie, Bluewater and Southern Pines then make public via postings on their respective websites.

The FERC also has authority over the construction and operation of U.S. pipeline transportation and storage facilities and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. In addition, the FERC s authority extends to maintenance of accounts and records, terms and conditions of service, depreciation and amortization policies, acquisition and disposition of facilities, initiation and discontinuation of services, imposition of creditworthiness and credit support requirements applicable to customers and relationships among pipelines and storage companies and certain affiliates.

Standards of Conduct for Transmission Providers. Historically, the FERC s standards of conduct regulations (now vacated) generally restricted access to U.S. interstate natural gas storage customer data by marketing and other energy affiliates, and placed certain conditions on services provided by U.S. storage facility operators to their affiliated gas marketing entities. The standards of conduct did not apply, however, to natural gas storage providers authorized to charge market-based rates that (i) were not interconnected with the jurisdictional facilities of any affiliated interstate natural gas pipeline and (ii) had no exclusive franchise area, no captive ratepayers, and no market power. The FERC found that Pine Prairie qualified for this exemption from the standards of conduct in January 2006 and Bluewater qualified for this exemption in October 2006.

In November 2006, the D.C. Circuit vacated the standards of conduct regulations with respect to natural gas pipelines and storage companies, and remanded the matter to the FERC. Following a notice of proposed rulemaking, in October 2008, the FERC issued revised Standards of Conduct for Transmission Providers (Standards of Conduct). The Standards of Conduct continue to exempt natural gas storage providers like Pine Prairie and Bluewater. The FERC has since issued three Orders on Rehearing and Clarification in October and November 2009 and April 2010. However, one request for rehearing of the April 2010 order is pending with the FERC. Accordingly, there may be further modifications to the Standards of Conduct upon rehearing.

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Natural Gas Price Transparency. In April 2007, the FERC issued a notice of proposed rulemaking (NOPR) regarding price transparency provisions of the NGA and the Energy Policy Act of 2005 (the EPAct 2005). In the notice, the FERC proposed to revise its regulations to, among other things, 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. In December 2007, the FERC issued Order No. 704 implementing the annual reporting provisions of the NOPR with minimal changes to the original proposal. The order became effective in February 2008. The FERC issued two orders on rehearing in 2008, and following a technical conference in March 2010, the FERC issued an order clarifying the reporting requirements in April 2010. Pine Prairie, Bluewater and Southern Pines are subject to these annual reporting requirements.

In November 2008, the FERC issued Order No. 720 requiring interstate pipelines and certain non-interstate facilities to post certain daily capacity and volume information. The rule extends to storage facilities (such as Bluewater) that provide no-notice service. The rule has been appealed, but pending the results of that appeal, Bluewater will be subject to a requirement to post volumes with respect to no-notice service flows at each receipt and delivery point.

Energy Policy Act of 2005. Under the 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 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1 million per day per violation for violations occurring after August 8, 2005. The anti-manipulation rule and enhanced civil penalty authority reflect an expansion of the FERC s NGA enforcement authority.

Other Proposed Regulation. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state commissions and the courts. The natural gas industry historically has been heavily regulated. Accordingly, we cannot provide assurances that the less stringent and pro-competition regulatory approach recently pursued by the FERC and Congress will continue.

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 2,200% 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.

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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 3,500 employees at December 31, 2010. 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 nine 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 distributions to our unitholders. Unitholders may be eligible for foreign tax credits with respect to allocable Canadian 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.

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Basis of Common Units

A unitholder s initial tax basis for a common unit is generally the amount paid for the common unit and the unitholder s share of our nonrecourse liabilities. A unitholder s basis is generally increased by the unitholder s share of our income and by any increases in the unitholder s share of our nonrecourse liabilities (or liabilities for which no partner bears the economic risk of loss). 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, 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. Payments of interest and dividends from Canada to other Plains entities will be subject to Canadian withholding tax that is treated as a distribution.

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

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

Risks Related to Our Business

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 credit rating or the ability to receive open credit could negatively affect our ability to purchase crude oil and LPG 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 market. Our ability to capture that benefit, however, is subject to numerous risks and uncertainties, including our maintaining an attractive credit rating and continuing to receive open credit from our suppliers and trade counterparties. For example, our ability to utilize our crude oil storage capacity for merchant activities to capture contango market opportunities is dependent upon having adequate credit facilities, including the total amount of credit facilities and the cost of such credit facilities, which enables us to finance the storage of the crude oil from the time we complete the purchase of the oil until the time we complete the sale of the oil.

We 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.

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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 we purchase by selling crude oil for physical delivery to third party users, such as independent refiners or major oil companies, or by entering into a future delivery obligation under 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, futures contracts 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 could expose us to risk of loss resulting from price changes. We are also exposed to basis risk when crude oil is purchased against one pricing index and sold against a different index. Moreover, we are exposed to some risks that are not hedged, including 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 810,000 barrels of crude oil, refined products and LPG. 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.

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, enacted in December 2006, requires the DOT to issue regulations for certain pipelines that were not previously subject to regulation. These new regulations, adopted in July 2008, include requirements for the establishment of additional 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 September 2010 Consent Decree. See Items 1 and 2. Business and Properties Regulation Environmental, Health and Safety Regulation Pipeline Safety/Pipeline and Storage Tank Integrity Management and Legal Proceedings United States Environmental Protection Agency v. Plains All American Pipeline, L.P.

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The acquisitions we have completed over the last several years have included pipeline assets of varying ages and maintenance and operational histories. Accordingly, for 2011 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 $7 million. A similar decline in volumes shipped from the San Joaquin Valley would result in an estimated $3 million decrease in annual transportation segment profit.

In addition, the recent 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 LPG shipped, purchased and gathered.

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

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

Fluctuations in demand can negatively affect our operating results.

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

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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.

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 timely and effectively to integrate the underlying assets and such assets perform at or near the levels anticipated in our acquisition projections.

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

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

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

Any acquisition involves potential risks, including:

- performance from the acquired 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.

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 tankage as it allows a party to simultaneously purchase production 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.

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

For our U.S. interstate common carrier pipelines subject to FERC regulation under the ICA, shippers may protest our pipeline tariff filings, 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.

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.

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, 2010, our consolidated debt outstanding was approximately $6.0 billion, consisting of approximately $4.6 billion principal amount of long-term debt (including senior notes) and approximately $1.3 billion of short-term borrowings. As of December 31, 2010, we had approximately $841 million of available borrowing capacity under our senior unsecured revolving credit facility and our senior secured hedged inventory facility.

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

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

- credit rating agencies may view our debt level negatively;

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

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

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

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

Our credit agreements prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, the agreements contain various covenants limiting our ability to, among other things, incur indebtedness if certain financial ratios are not maintained, grant liens, engage in transactions with affiliates, enter into sale-leaseback transactions, and sell substantially all of our assets or enter into a merger or consolidation. Our credit facility treats a change of control as an event of default and also requires us to maintain a certain debt coverage ratio. Our senior notes do not restrict distributions to unitholders, but a default under our credit agreements will be treated as a default under the senior notes. Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Facilities and 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 debt maturing in the next several years and current maturities, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, then we could experience an increase in our borrowing costs, face difficulty accessing capital markets or incurring additional indebtedness, be unable to receive open credit from our suppliers and trade counterparties, be unable to benefit from swings in market prices and shifts in market structure during periods of volatility in the crude oil market or suffer a reduction in the market price of our common units. If we are unable to access the capital markets on favorable terms at the time a debt obligation becomes due in the future, we might be forced to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected rates.

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 cargoes 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 cargoes.

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

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

We are dependent on use of 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. We are currently a hold-over tenant with respect to such facilities. If we are unable to renew the agreement that allows us to utilize these dock facilities, and if other alternative dock access cannot be arranged, the volumes of crude oil that we presently receive from our customers in the Los Angeles basin may be reduced, which could result in a reduction of facilities segment revenue and cash flow.

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

We use both fixed and variable rate debt, and we are exposed to market risk due to the floating interest rates on our credit facilities. As of December 31, 2010, we had approximately $6.0 billion of consolidated debt, of which approximately $4.1 billion was at fixed interest rates and approximately $1.9 billion was at variable interest rates (including $300 million of interest rate derivatives that swap fixed-rate debt for floating). From time to time we use interest rate derivatives to hedge interest obligations on specific debt issuances, including anticipated debt issuances. Our results of operations, cash flows and financial position could be adversely affected by significant increases in interest rates above current levels. Additionally, increases in interest rates could adversely affect our 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.

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

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

An impairment of goodwill could reduce our earnings.

At December 31, 2010, we had $1.4 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.

Our natural gas storage facilities are new and have limited operating history. The 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, the facilities are new and have a limited operating history. If 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.

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.

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

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

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

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

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

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

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

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

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

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

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

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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 and subsidiary guarantees is unsecured and will be effectively subordinated to our existing and future secured indebtedness as well as to any existing and future indebtedness of our subsidiaries that do not guarantee the notes.

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

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

Our leverage is significant in relation to our partners capital. At December 31, 2010, our total outstanding debt was approximately $6.0 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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Tax Risks to Common Unitholders

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

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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 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 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.

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

In response to changes in Canadian tax legislation and the Fifth Protocol to the U.S./Canada Income Tax Convention, on January 1, 2011, we restructured our Canadian investment. All Canadian operations are now carried on in entities that are treated as corporations for Canadian tax purposes and subject to Canadian federal and provincial income tax. Dividend and interest payments from Canada are subject to withholding taxes that are reduced from the applicable statutory withholding tax rate through the application of a tax treaty. If the Canadian tax authorities were to challenge the application of the tax treaty, it could result in a reduction of available cash.

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

The IRS has made no determination as to our status as a partnership for federal income tax purposes or as to any other matter affecting us. The IRS may adopt positions that differ from the 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

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price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution or debt service.

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

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

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

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

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

Investment in common units by tax-exempt entities, such as employee benefit plans and 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. 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, local and non-U.S. 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 unitholders will be required to file Canadian tax returns with respect to an investment in our units.

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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.

Because there is no tax concept of loaning a partnership interest, 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 the loaned units, he 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 the unitholder 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 would not have appeared to 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.

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

None.

Item 3. ***Legal Proceedings***

United States Environmental Protection Agency v. Plains All American Pipeline, L.P. In September 2010, the United States District Court for the Southern District of Texas entered an order approving a Consent Decree that represented our settlement agreement with the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Justice (DOJ) regarding a 2004 crude oil release that reached the Pecos River and a 2005 crude oil release that reached the Sabine River, as well as eight smaller releases. Pursuant to the Consent Decree, we paid $3.25 million in civil penalties, which we had fully reserved in our contingency accrual. Over the last several years we have proactively developed and implemented risk assessment, pipeline integrity and leak detection procedures that are incremental to those mandated by regulation. As a result of this effort and the ongoing process with EPA and DOJ, many of the operational requirements contained in the Consent Decree have already been incorporated into our operating practices, and the anticipated costs of compliance have been incorporated into our planning.

SemCrude L.P., et al Debtors/Samson Resources Company (U.S. Bankruptcy Court Delaware). We will from time to time have claims relating to insolvent suppliers, customers or counterparties, such as the bankruptcy proceedings of SemCrude, which commenced in July 2008. Statutory protections and our contractual rights of setoff covered substantially all of our pre-petition claims against SemCrude and such claims have now been resolved. In separate actions, certain creditors of SemCrude, led by Samson Resources Company, have also filed state court actions alleging a producer s lien on crude oil sold to SemCrude and its affiliates, and the continuation of such lien when SemCrude and its affiliates subsequently sold the oil to purchasers such as us. On May 29, 2009, we filed a complaint for declaratory relief to resolve these claims. Fourteen state court actions have been consolidated in Bankruptcy Court. One action is in Federal Court in New Mexico. We intend to vigorously defend our contractual and statutory rights.

ExxonMobil Corp. v. GATX Corp. (Superior Court of New Jersey Gloucester County). This Pacific legacy matter was filed by ExxonMobil in April 2003 and involves the allocation of responsibility for remediation of MTBE and other petroleum product contamination at our terminal facility in Paulsboro, New Jersey, which we acquired in the Pacific merger. We estimate that the cost to effectively remediate will be approximately $3.5 million, which amount may be higher or lower depending on the nature and extent of the cleanup. Both ExxonMobil and GATX were prior owners of the terminal. We contend that ExxonMobil and/or GATX are primarily responsible for the majority of the remediation costs. We are in dispute with Kinder Morgan (as successor in interest to GATX) regarding the indemnity by GATX in favor of Pacific in connection with Pacific s purchase of the facility. We are vigorously defending against any claim that Plains Products Terminals LLC (formerly known as Pacific Atlantic Terminals LLC, referred to here as PPT) is directly or indirectly liable for damages or costs associated with the MTBE contamination.

New Jersey Department of Environmental Protection v. ExxonMobil Corp. et al. In a matter related to ExxonMobil v. GATX, in June 2007, the NJDEP brought suit against GATX, ExxonMobil and PPT to recover natural resources damages associated with, and to require remediation of, the contamination. ExxonMobil and GATX have filed third-party demands against PPT, seeking indemnity and contribution. The natural resources damages have been settled and set at $1.1 million payable to the State of New Jersey; however, PPT s allocated share of this liability is being disputed by PPT with GATX. Court approval of the settlement is pending.

EPA v. Rocky Mountain Pipeline System. In February 2009, we received a request for information from EPA regarding aspects of the fuel handling activities of RMPS, a subsidiary acquired in the Pacific merger, at two truck terminals in Colorado. These activities included the mixture of certain blendstocks with gasoline. We provided the information requested, and cooperated in EPA s investigation of such activities. In January 2010, we received a notice of violations from EPA, alleging failure of RMPS to comply with provisions of the Clean Air Act related to registration, sampling, recording and reporting in connection with such activities. EPA further alleges that the violations occurred on an ongoing basis from October 2006 through February 2009. EPA has referred the matter to the DOJ. We continue to engage in discussion with EPA, and to emphasize those factors that should mitigate the severity of any penalties imposed. In December 2009, RMPS self-reported late filing of certain reports required under Clean Air Act Diesel Fuel Regulations. All reports have now been filed.

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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.

Environmental

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. 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.

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 spend 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.

At December 31, 2010, our reserve for environmental liabilities totaled approximately $66 million, of which approximately $10 million is classified as short-term and $56 million is classified as long-term. At December 31, 2010, we have recorded receivables totaling approximately $5 million for amounts that are probable of recovery under insurance and from third parties under indemnification agreements.

In some cases, the actual cash expenditures may not occur for three to five years. Our estimates used in these reserves are based on 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.

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. In addition, although we believe that we have established adequate reserves to the extent that such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

Item 4. (Removed and Reserved)

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PART II

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

Our common units are listed and traded on the New York Stock Exchange (NYSE) under the symbol PAA. As of February 22, 2011, the closing market price for our common units was $63.79 per unit and there were approximately 125,000 record holders and beneficial owners (held in street name). As of February 22, 2011, there were 141,199,175 common units outstanding.

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

	Common Unit Price Range				Cash
		High		Low		Distributions (1)
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
2009						
4th Quarter	$	53.37	$	45.45	$	0.9275
3rd Quarter	$	50.33	$	42.50	$	0.9200
2nd Quarter	$	45.52	$	36.25	$	0.9050
1st Quarter	$	40.98	$	34.00	$	0.9050

(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

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

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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

Following the distribution in February 2011 (as discussed below), the aggregate remaining incentive distribution reductions are approximately $5 million.

We paid $160 million to the general partner in incentive distributions in 2010. Additionally, on February 14, 2011, we paid a quarterly distribution of $0.9575 per unit applicable to the fourth quarter of 2010, of which approximately $46 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 2010, 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).

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

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2010, 2009, 2008, 2007 and 2006 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,				
	2010	2009	2008	2007	2006
	(in millions, except for per unit data)				
Statement of operations data:					
Total revenues (1)	$ 25,893	$ 18,520	$ 30,061	$ 20,394	$ 22,445
Income before cumulative effect of change in accounting principle (2)	$ 514	$ 580	$ 437	$ 365	$ 279
Net income	$ 514	$ 580	$ 437	$ 365	$ 285
Net income attributable to Plains	$ 505	$ 579	$ 437	$ 365	$ 285
Per unit data:					
Basic net income before cumulative effect of change in accounting principle (2)	$ 2.41	$ 3.34	$ 2.66	$ 2.47	$ 2.85
Basic net income after cumulative effect of change in accounting principle	$ 2.41	$ 3.34	$ 2.66	$ 2.47	$ 2.93
Diluted net income before cumulative effect of change in accounting principle (2)	$ 2.40	$ 3.32	$ 2.64	$ 2.45	$ 2.82
Diluted net income after cumulative effect of change in accounting principle	$ 2.40	$ 3.32	$ 2.64	$ 2.45	$ 2.90
Declared distributions per limited partner unit (3)	$ 3.76	$ 3.62	$ 3.50	$ 3.28	$ 2.87
Balance sheet data (at end of period):					
Total assets	$ 13,703	$ 12,358	$ 10,032	$ 9,906	$ 8,715
Long-term debt	$ 4,631	$ 4,142	$ 3,259	$ 2,624	$ 2,626
Total debt	$ 5,957	$ 5,216	$ 4,286	$ 3,584	$ 3,627
Partners capital	$ 4,573	$ 4,159	$ 3,552	$ 3,424	$ 2,977
Other data:					
Net cash provided by (used in) operating activities	$ 259	$ 365	$ 857	$ 796	$ (276)
Net cash used in investing activities	$ (583)	$ (660)	$ (1,339)	$ (663)	$ (1,651)
Net cash provided by (used in) financing activities	$ 336	$ 312	$ 464	$ (124)	$ 1,927
Capital expenditures:					
Acquisitions	$ 407	$ 393	$ 735	$ 125	$ 3,021
Internal growth projects	$ 355	$ 364	$ 491	$ 525	$ 332
Maintenance	$ 93	$ 81	$ 81	$ 50	$ 28
Investments in unconsolidated subsidiaries	$	$ 15	$ 37	$ 9	$ 44

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	Year Ended December 31,				
	2010	2009	2008	2007	2006
Volumes (4) (5) (6)					
Transportation segment (average daily volumes in thousands of barrels):					
Tariff activities	2,889	2,836	2,851	2,712	2,106
Trucking	97	85	97	105	101
Transportation segment total	2,986	2,921	2,948	2,817	2,207
Facilities segment:					
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	61	56	53	46	25
Natural gas storage (average monthly capacity in bcf)	47	26	14	13	13
LPG processing (average daily throughput in thousands of barrels)	14	15	17	18	12
Facilities segment total (average monthly capacity in millions of barrels)	70	61	56	48	27
Supply & Logistics segment (average daily volumes in thousands of barrels):					
Crude oil lease gathering purchases	620	612	658	685	650
LPG sales	96	105	103	90	70
Waterborne foreign crude oil imported	68	55	80	71	63
Supply & Logistics segment total	784	772	841	846	783

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

(2) Due to the January 1, 2006 change in our method of accounting for unit-based payment transactions, we recognized a cumulative effect of change in accounting principle of approximately $6 million.

(3) 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.

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

(5) In September 2009, we acquired the remaining 50% indirect interest in PNGS, which resulted in our 100% ownership of the natural gas storage business and related operating entities. Natural gas storage volumes for January 2006 through August 2009 are netted to

our 50% interest in PNGS. Beginning in September 2009, volumes represent our 100% interest in PNGS. See Note 3 to our Consolidated Financial Statements for additional discussion regarding the PNGS acquisition.

(6) 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.

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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 Spending 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 provide transportation, storage, terminalling and supply and logistics services with respect to crude oil, refined products and LPG. Through our general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P. (NYSE: PNG), we also engage in the development and operation of natural gas storage facilities. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries 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 Spending and Significant Activities

During 2010, our net income attributable to Plains was $505 million, which was a $74 million year-over-year decrease as compared to that recognized during 2009. The major items impacting comparability between periods are:

- The unfavorable results experienced within our supply and logistics segment, which were impacted by:
- lower LPG margins;
- our derivative activities; and
- less favorable crude oil quality differentials and market structure.

- The negative impact to all segments resulting from our equity compensation expense that increased by approximately $30 million during 2010 compared to 2009.

- The favorable results experienced within:
- our facilities segment, which primarily resulted from expansions in our asset base through acquisitions and our ongoing internal growth projects; and
- our transportation segment, which primarily reflects impacts of favorable foreign currency exchange rates, increased tariff rates and other various net favorable effects.

- The negative impact of increased depreciation and amortization expense and interest expense associated with our expanded asset base and related financing costs.

See the Results of Operations section below for further discussion and analysis of our operating segments.

Other key items impacting 2010 include (i) the completion of debt and equity offerings for net proceeds of approximately $692 million, (ii) the completion of PNG s initial public offering (IPO) for net proceeds of $268 million received from the sale of 13,478,000 PNG common units and (iii) approximately $509 million of net borrowings under our credit facilities, including $260 million of borrowings under PNG s credit facility that was entered into in conjunction with the IPO. These net proceeds were used for (i) the repayment of our $175

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million, 6.25% senior notes, (ii) funding of our ongoing expansion capital program and acquisitions (as further discussed in the following sections) and (iii) other general partnership purposes.

Acquisitions and Internal Growth Projects

We completed a number of acquisitions and capital expansion projects in 2010, 2009 and 2008 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,		
	2010	2009	2008
Acquisition capital (1)	$ 407	$ 393	$ 735
Internal growth projects	355	364	491
Maintenance capital	93	81	81
Investment in unconsolidated entities (1)		15	37
	$ 855	$ 853	$ 1,344

(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.

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 effective 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 2010, 2009 and 2008 is set forth in the table below (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Nexen Holdings U.S.A. Inc.	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	
Rainbow	05/01/2008	$ 687	Transportation
Other	Various	48	Facilities
2008 Total		$ 735	

Internal Growth Projects

Our 2010 projects included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2010, 2009 and 2008 projects (in millions):

Projects	**2010**	**2009**	**2008**
PNGS (1) (2)	$ 85	$ 26	$
Cushing - Phases VII and VIII	25	25	
Cushing - Phases IX through XI (1)	21		
St. James - Phases I through IV (1)	21	73	44
Patoka tankage - Phases I through III	20	22	56
Edmonton land	17		
West Texas gathering lines	15		
Pier 400 (1)	11	18	10
Wichita Falls tanks	9		
Nipisi storage and truck terminal	6	18	
Kerrobert pumping project	1	33	9
Rangeland tankage		36	12
Paulsboro tankage		11	30
Salt Lake City expansion		8	154
Fort Laramie tank expansion		2	20
Other projects (3)	124	92	156
Total	$ 355	$ 364	$ 491

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(1) These projects will continue into 2011. See Liquidity and Capital Resources Capital Expenditures and Distributions Paid to Our Unitholders, General Partner and Noncontrolling Interests 2011 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.

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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, 2010, we estimate that approximately 3% 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 also compare our market capitalization to our book equity on a quarterly basis, to determine if there may be an indicator of impairment. As of December 31, 2010, our market capitalization exceeded the book value of our equity; therefore, since there were no events or changes in circumstances indicating impairment issues, we determined that it was not necessary to perform our goodwill impairment test as of December 31, 2010. We will continue to monitor the market and any changes in circumstances to determine if a triggering event occurs and will perform a goodwill impairment analysis if deemed necessary. We did not have any goodwill impairments in 2010, 2009 or 2008. 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 $12 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 $98 million, $68 million and $24 million in 2010, 2009 and 2008, 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, we conducted a review to assess the useful lives of our property and equipment. See Note 2 to our Consolidated Financial Statements.

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

During 2010, we recognized impairments of approximately $13 million for assets taken out of service. Impairments of less than $1 million and approximately $5 million were recognized during 2009 and 2008, 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 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 15 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.

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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 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 within 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)			
				2010-2009		2009-2008	
	2010	2009	2008	$	%	$	%
	(In millions, except per unit data)						
Transportation segment profit	$ 516	$ 477	$ 445	$ 39	8%	$ 32	7%
Facilities segment profit	270	208	153	62	30%	55	36%
Supply & Logistics segment profit	240	345	221	(105)	(30)%	124	56%
Total segment profit	1,026	1,030	819	(4)	(0)%	211	26%
Depreciation and amortization	(256)	(236)	(211)	(20)	(8)%	(25)	(12)%
Interest expense	(248)	(224)	(196)	(24)	(11)%	(28)	(14)%
Other income/(expense), net	(9)	16	33	(25)	(156)%	(17)	(52)%
Income tax benefit/(expense)	1	(6)	(8)	7	117%	2	25%
Net income	514	580	437	(66)	(11)%	143	33%
Less: Net income attributable to noncontrolling interests	(9)	(1)		(8)	(800)%	(1)	N/A
Net income attributable to Plains	$ 505	$ 579	$ 437	$ (74)	(13)%	$ 142	32%
Net income attributable to Plains:							
Earnings per basic limited partner unit	$ 2.41	$ 3.34	$ 2.66	$ (0.93)	(28)%	$ 0.68	26%
Earnings per diluted limited partner unit	$ 2.40	$ 3.32	$ 2.64	$ (0.92)	(28)%	$ 0.68	26%
Basic weighted average units outstanding	137	130	120	7	5%	10	8%
Diluted weighted average units outstanding	138	131	121	7	5%	10	8%

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

	For the Twelve Months Ended December 31,			Favorable/(Unfavorable)			
				2010-2009		2009-2008	
	2010	2009	2008	$	%	$	%
	(In millions, except per unit data)						
Net income	$ 514	$ 580	$ 437	$ (66)	(11)%	$ 143	33%
Add:							
Depreciation and amortization	256	236	211	(20)	(8)%	(25)	(12)%
Income tax (benefit)/expense	(1)	6	8	7	117%	2	25%
Interest expense	248	224	196	(24)	(11)%	(28)	(14)%
EBITDA	$ 1,017	$ 1,046	$ 852	$ (29)	(3)%	$ 194	23%
Selected Items Impacting Comparability - Income/(Loss):							
Inventory valuation adjustments net of gains/(losses) from related derivative activities (1)	$	$ 24	$ (11)	$ (24)	(100)%	$ 35	318%
Gains/(losses) from other derivative activities (1)	(14)	34	7	(48)	(141)%	27	(386)%
Equity compensation expense (2)	(67)	(50)	(21)	(17)	34%	(29)	(138)%
Gains on Rainbow acquisition-related foreign currency and linefill hedges (3)			11		0%	(11)	100%
Net gain/(loss) on foreign currency revaluation (4)		12	(21)	(12)	(100)%	33	157%
Other(5)	(8)	4		(12)	(300)%	4	0%
Selected Items Impacting Comparability	$ (89)	$ 24	$ (35)	$ (113)	(471)%	$ 59	169%
EBITDA	$ 1,017	$ 1,046	$ 852	$ (29)	(3)%	$ 194	23%
Selected Items Impacting Comparability	89	(24)	35	113	471%	(59)	(169)%
Adjusted EBITDA	$ 1,106	$ 1,022	$ 887	$ 84	8%	$ 135	15%
Adjusted EBITDA	$ 1,106	$ 1,022	$ 887	$ 84	8%	$ 135	15%
Interest expense	(248)	(224)	(196)	(24)	(11)%	(28)	(14)%
Maintenance capital	(93)	(81)	(81)	(12)	(15)%		0%
Current income tax (expense)/benefit	1	(15)	(9)	16	107%	(6)	(67)%
Equity earnings in unconsolidated entities, net of distributions	6	(8)	(4)	14	175%	(4)	(100)%
Distributions to noncontrolling interests (6)	(15)	(2)		(13)	(650)%	(2)	N/A
DCF	$ 757	$ 692	$ 597	$ 65	9%	$ 95	(16)%

(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. 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.

(2) 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 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. The equity compensation expense attributable to the awards not considered a selected item impacting comparability is approximately $31 million, $18 million and $3 million for the twelve-month periods ended December 31, 2010, 2009 and 2008, respectively. See Note 10 to our Consolidated Financial Statements for a comprehensive discussion regarding our Equity Compensation Plans.

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(3) Represents a gain on the foreign currency hedge and commodity price risk hedge that we entered into in connection with the Rainbow acquisition. We classified this gain as a selected item impacting comparability as it was specific to this acquisition and not indicative of our core operating activities. See Note 3 to our Consolidated Financial Statements for further discussion regarding the Rainbow acquisition.

(4) During 2009 and 2008, 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 such periods 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.

(5) Other includes (i) a net loss on the early repayment of senior notes of $6 million and $4 million for 2010 and 2009, respectively, (ii) PNGS contingent consideration fair value adjustment of $2 million and $1 million for 2010 and 2009, respectively and (iii) a net gain on the purchase of the remaining 50% interest in PNGS of $9 million in 2009.

(6) 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)	**Year Ended December 31,**			**Favorable/(Unfavorable)**			
				2010-2009		**2009-2008**	
(in millions, except per barrel amounts)	**2010**	**2009**	**2008**	**$**	**%**	**$**	**%**
Revenues (1)							
Tariff activities	$ 937	$ 867	$ 800	$ 70	8%	$ 67	8%
Trucking	108	94	127	14	15%	(33)	(26)%
Total transportation revenues	1,045	961	927	84	9%	34	4%
Cost and Expenses (1)							
Trucking costs	(73)	(63)	(88)	(10)	(16)%	25	28%
Field operating costs (excluding equity compensation expense)	(346)	(333)	(331)	(13)	(4)%	(2)	(1)%
Equity compensation expense - operations (2)	(12)	(9)	(1)	(3)	(33)%	(8)	(800)%
	(65)	(61)	(56)	(4)	(7)%	(5)	(9)%

Segment general and administrative expenses (excluding equity compensation expense)												
Equity compensation expense - general and administrative (2)		(36)		(25)		(11)		(11)	(44)%		(14)	(127)%
Equity earnings in unconsolidated entities		3		7		5		(4)	(57)%		2	40%
Segment profit	$	516	$	477	$	445	$	39	8%	$	32	7%
Maintenance capital	$	67	$	57	$	54	$	(10)	(18)%	$	(3)	(6)%
Segment profit per barrel	$	0.47	$	0.45	$	0.41	$	0.02	4%	$	0.04	10%

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Average Daily Volumes (in thousands of barrels per day) (3)	**Year Ended December 31, 2010**	**2009**	**2008**	**Favorable/(Unfavorable) 2010-2009 Volumes**	**%**	**2009-2008 Volumes**	**%**
Tariff activities							
All American	39	40	45	(1)	(3)%	(5)	(11)%
Basin	378	394	377	(16)	(4)%	17	5%
Capline	223	193	219	30	16%	(26)	(12)%
Line 63/Line 2000	109	131	147	(22)	(17)%	(16)	(11)%
Salt Lake City Area Systems	135	131	93	4	3%	38	41%
Permian Basin Area Systems	371	368	372	3	1%	(4)	(1)%
Manito	61	63	70	(2)	(3)%	(7)	(10)%
Rainbow	187	183	129	4	2%	54	42%
Rangeland	52	53	58	(1)	(2)%	(5)	(9)%
Refined products	116	100	109	16	16%	(9)	(8)%
Other	1,218	1,180	1,232	38	3%	(52)	(4)%
Tariff activities total	2,889	2,836	2,851	53	2%	(15)	(1)%
Trucking	97	85	97	12	14%	(12)	(12)%
Transportation segment total	2,986	2,921	2,948	65	2%	(27)	(1)%

(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.

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

Operating Revenues and Volumes. As noted in the table above, our total transportation segment revenues, net of trucking costs, increased year-over-year for each comparative period presented. Our volumes increased during 2010 compared to 2009 and declined slightly during 2009 compared to 2008. The most noteworthy favorable volume variance for 2010 compared to 2009 is primarily 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. Volumes were further favorably impacted by increased trucking volumes related to increased short-haul shipments and the addition of a heavy oil truck terminal at Nipisi, Alberta.

Revenues, net of trucking costs, for the years ended December 31, 2010, 2009 and 2008 were positively impacted by the net effect of a number of factors including:

- 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 2010, 2009 and 2008 were $1.03 CAD: $1.00 USD, $1.14 CAD: $1.00 USD and $1.07 CAD: $1.00 USD, respectively. Therefore, revenues from our Canadian pipeline systems and trucking operations were favorably impacted for 2010 compared to 2009 by approximately $24 million due to the appreciation of the Canadian dollar relative to the U.S. dollar. In turn, such revenues for 2009 compared to 2008 were unfavorably impacted by approximately $11 million due to the depreciation of the Canadian dollar relative to the U.S. dollar.

- Rate Increases Revenues were favorably impacted by increasing tariff rates on our intrastate and Canadian pipelines as well as on our pipelines regulated by the Federal Energy Regulatory Commission.

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• 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. Loss allowance revenues increased by approximately $9 million for 2010 compared to 2009 and $22 million for 2009 compared to 2008. 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).

• Trucking Business Activity 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, partially offset by higher fuel costs. In contrast, trucking revenues, net of costs, decreased by approximately $8 million for 2009 compared to 2008 primarily due to volume decreases resulting from decreased demand, as well as an effort to eliminate lower margin activities. Such unfavorable variances were partially offset by lower fuel costs.

• Rainbow Acquisition The Rainbow acquisition, completed in May 2008, contributed approximately $16 million of incremental revenue to 2009 compared to 2008.

• Salt Lake City Area Expansion During the fourth quarter of 2008, we completed a 94-mile expansion of our Salt Lake Area system. Incremental revenues from completion of the Salt Lake City Area expansion added approximately $7 million to revenues in 2009 relative to 2008 associated with volume increases.

Costs and Expenses. In general, our overall transportation costs and expenses have remained relatively consistent on a per barrel basis during 2010, 2009 and 2008. Included in these results are the impacts of foreign exchange rates, which had an unfavorable impact of approximately $10 million in 2010 as compared to 2009 and a favorable impact of approximately $5 million in 2009 as compared to 2008. In addition, our equity compensation expense increased in 2010 compared to 2009. A significant component of this increase is associated with the determination that a PAA distribution level of $4.00 per limited partner (LP) unit is probable of occurring. A majority of our equity compensation awards 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 (such as a $4.00 distribution per LP unit becoming 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 be as if we had been accruing for these awards since the grant date. During 2009, equity compensation expense increased by $22 million as compared to 2008 primarily due to an increase in PAA unit price for 2009 relative to 2008. At the end of 2009, our unit price was $52.85 per common unit as compared to $34.69 per common unit at the end of 2008, which increases the fair value of our outstanding liability classified LTIPs. In addition to probability and price fluctuations, our equity compensation expense is impacted by additional equity compensation grants and forfeitures during each period (including the Class B grants and forfeitures). See Note 10 to our Consolidated Financial Statements for additional information on our equity compensation plans.

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- *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 2010 compared to 2009 is primarily due to increased spending on various pipeline integrity projects as well as timing of repairs between years.

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:

Operating Results (1) (in millions, except per barrel amounts)	For the Year Ended December 31, 2010	2009	2008	Favorable/(Unfavorable) 2010-2009 $	%	2009-2008 $	%
Storage and terminalling revenues (1)	$ 490	$ 362	$ 270	$ 128	35%	$ 92	34%
Storage related costs (natural gas related)	(23)	(5)		(18)	(360)%	(5)	N/A
Field operating costs (excluding equity compensation expense)	(140)	(120)	(104)	(20)	(17)%	(16)	(15)%
Equity compensation expense - operations (2)	(2)	(1)		(1)	(100)%	(1)	N/A
Segment general and administrative expenses (excluding equity compensation expense)	(39)	(26)	(18)	(13)	(50)%	(8)	(44)%
Equity compensation expense - general and administrative (2)	(16)	(10)	(4)	(6)	(60)%	(6)	(150)%
Equity earnings in unconsolidated entities		8	9	(8)	(100)%	(1)	(11)%
Segment profit	$ 270	$ 208	$ 153	$ 62	30%	$ 55	36%
Maintenance capital	$ 17	$ 16	$ 23	$ (1)	(6)%	$ 7	30%
Segment profit per barrel	$ 0.32	$ 0.29	$ 0.23	$ 0.03	10%	$ 0.06	26%

Volumes (3) (4) (5)	For the Year Ended December 31, 2010	2009	2008	Favorable/(Unfavorable) 2010-2009 Volumes	%	2009-2008 Volumes	%
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	61	56	53	5	9%	3	6%
Natural gas storage (average monthly capacity in billions of cubic feet)	47	26	14	21	81%	12	86%
LPG processing (average throughput in thousands of barrels per day)	14	15	17	(1)	(7)%	(2)	(12)%
Facilities segment total (average monthly capacity in millions of barrels)	70	61	56	9	15%	5	9%

(1) Includes 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.

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(3) 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.

(4) In September 2009, we acquired the remaining 50% indirect interest in PNGS, which resulted in our 100% ownership of the natural gas storage business and related operating entities. Therefore, natural gas storage volumes for January 2008 through August 2009 are netted to our 50% interest in PNGS. Beginning in September 2009, volumes represent our 100% interest in PNGS. See Note 3 to our Consolidated Financial Statements for additional discussion regarding the PNGS acquisition.

(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.

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

Operating Revenues and Volumes. As noted in the table above, our facilities segment revenues (less storage related costs) and volumes increased year-over-year for each comparative year presented. Revenues and volumes for the comparative periods were positively impacted primarily by the net effect of factors discussed below:

- Acquisitions 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.

Revenues and volumes for 2009 compared to 2008 were impacted by the PNGS acquisition and the acquisition of a natural gas processing business as mentioned above. Revenues and volumes for 2009 compared to 2008 were also impacted by the San Pedro acquisition, which closed during the fourth quarter of 2008. Such acquisitions contributed approximately $36 million in additional revenue for the year ended December 31, 2009.

- Expansion Projects Expansion projects that were completed in phases throughout recent years also favorably impacted revenues and volumes. These expansion projects, which were completed at some of our major terminal locations, increased revenues by a combined $14 million for the year ended December 31, 2010 compared to the year ended December 31, 2009 and by a combined $31 million for the year ended December 31, 2009 compared to the year ended December 31, 2008. Aggregate volumes at these facilities increased by approximately 5 million barrels for 2010 compared to 2009 and by approximately 5 million barrels for 2009 compared to 2008.

- Leased Tankage Revenues for the year ended December 31, 2010 and December 31, 2009 also increased as a result of general escalations on existing leases.

Costs and Expenses. In general, our overall facilities costs and expenses have remained relatively constant on a per barrel basis during 2010, 2009 and 2008. We have experienced a small increase in field operating costs and general and administrative costs on a per barrel basis and the absolute amount of expense has increased for 2010 compared to 2009 and 2009 compared to 2008 primarily due to (i) continued growth through additional tankage placed into service over the last few years at some of our major terminal locations and (ii) acquisitions such as the PNGS and natural gas processing acquisitions completed in the second and third quarters of 2009. Our 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.

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Equity Earnings in Unconsolidated Entities. Equity earnings in unconsolidated entities decreased during 2010 compared to 2009 due to the PNGS acquisition in September 2009 that increased our interest from 50% to 100%. See Note 3 to our Consolidated Financial Statements for additional discussion regarding this acquisition.

Maintenance Capital. The decrease in maintenance capital from 2009 compared to 2008 is primarily due to a decrease in API 653 repairs required to meet our May 2009 compliance deadline.

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 increases or decreases in our supply and logistics segment volumes (which consist of (i) lease gathered crude oil purchase volumes, (ii) LPG sales volumes and (iii) waterborne foreign crude oil imported) as well as 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,** **2010**	**2009**	**2008**	**Favorable/(Unfavorable)** **2010-2009** **Revenues**	**%**	**2009-2008** **Revenues**	**%**
Revenues	$ 24,990	$ 17,759	$ 29,350	$ 7,231	41%	$ (11,591)	(39)%
Purchases and related costs (2)	(24,448)	(17,141)	(28,873)	(7,307)	(43)%	11,732	41%
Field operating costs (excluding equity compensation expense)	(195)	(183)	(185)	(12)	(7)%	2	1%
Equity compensation expense - operations (3)	(3)	(1)		(2)	(200)%	(1)	N/A
Segment general and administrative expenses (excluding equity compensation expense)	(75)	(67)	(63)	(8)	(12)%	(4)	(6)%
Equity compensation expense - general and administrative (3)	(29)	(22)	(8)	(7)	(32)%	(14)	(175)%
Segment profit	$ 240	$ 345	$ 221	$ (105)	(30)%	$ 124	56%
Maintenance capital	$ 9	$ 8	$ 4	$ (1)	(13)%	$ (4)	(100)%
Segment profit per barrel	$ 0.84	$ 1.22	$ 0.72	$ (0.38)	(31)%	$ 0.50	69%

Average Daily Volumes (4) **(in thousands of barrels per day)**	**For the Year Ended December 31,** **2010**	**2009**	**2008**	**Favorable (Unfavorable)** **2010-2009** **Volume**	**%**	**2009-2008** **Volume**	**%**
Crude oil lease gathering purchases	620	612	658	8	1%	(46)	(7)%
LPG sales	96	105	103	(9)	(9)%	2	2%

Waterborne foreign crude oil imported	68	55	80	13	24%	(25)	(31)%
Supply & Logistics segment total	784	772	841	12	2%	(69)	(8)%

(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged inventory purchases) of approximately $17 million, $11 million and $21 million for the years ended December 31, 2010, 2009 and 2008, respectively.

(3) 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.

(4) Calculated based on crude oil lease gathered volumes, LPG sales volumes and waterborne foreign crude oil imported volumes.

The New York Mercantile Exchange (NYMEX) benchmark price of crude oil ranged from approximately $64 to $92 per barrel, $33 to $82 per barrel and $32 to $147 per barrel during 2010, 2009 and 2008, respectively. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the purchase and sale, the absolute amount of revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those purchases and sales will not necessarily have a corresponding increase or decrease.

Generally, we expect a base level of earnings from our supply and logistics segment that 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 translation 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 year-to-year may have a significant effect on financial performance.

Operating Revenues and Volumes. 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. LPG margins for 2010 were negatively impacted by lower demand. In addition, 2009 margins were higher than expected due to the liquidation of lower valued inventory following a write-down of inventory values during 2008. As for our derivative activities, we recognized net mark-to-market losses of approximately $17 million during 2010. The 2010 period was also unfavorably impacted compared to 2009 by (i) less favorable crude oil quality differentials and (ii) a less favorable market structure. These unfavorable variances were partially offset by improved margins within our lease gathering activities.

Revenues, net of purchases and related costs, increased by approximately $141 million or 30% in 2009 compared to 2008. The primary reasons for the stronger performance in 2009 were (i) strong crude oil contango margins in the first four months of the year (during this period the contango market was as wide as $8.49 per barrel); (ii) strong LPG margins in the fourth quarter of the year due to strong crop drying demand in the quarter and colder than normal weather the latter half of the quarter; (iii) the negative impacts of Hurricanes Gustav and Ike in 2008; and (iv) derivative activities, net of inventory valuation adjustments, were a net gain of $62 million in 2009 compared to a net loss of $7 million in 2008. The derivative gains in 2009 are generally offset by future physical positions that are not included in the mark-to-market calculation for various reasons including that they qualify for the normal purchase and normal sale scope exception under FASB guidance. These items more than offset a lower net margin from our lease gathering activities, which was primarily due to lower volumes as we eliminated some of our less profitable purchases.

Field Operating Costs. Field operating costs (excluding equity compensation expenses) increased in 2010 compared to 2009 primarily due to an increase in truck-hauled lease volumes which resulted in increased driver commissions, transport fuel costs and third party trucking fees. Additionally, transport fuel costs were negatively impacted in 2010 by higher diesel fuel prices.

General and Administrative Expenses. General and administrative expenses (excluding equity compensation expenses as discussed below) increased in 2010 compared to 2009 and in 2009 compared to 2008 primarily due to increased salary and benefit costs consistent with the overall growth of the segment and changes in allocation methodology among segments.

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

Maintenance Capital. The increase in maintenance capital for the year ended December 31, 2009 compared to the year ended December 31, 2008 is primarily due to truck and trailer fleet replacements and rebuilds.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense was $256 million for the year ended December 31, 2010 compared to $236 million and $211 million for the years ended December 31, 2009 and 2008, respectively. The increases in 2010, 2009 and 2008 related primarily to an increased amount of depreciable assets stemming from our acquisition activities and internal growth projects. The increase in depreciation expense in 2010 was partially offset by a $23 million reduction related to the extension 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 current technology. Amortization of debt issue costs was $7 million, $6 million and $4 million in 2010, 2009 and 2008, respectively.

Included in depreciation expense for the years ended December 31, 2010, 2009 and 2008 is a net loss of approximately $13 million, a net loss of approximately $1 million and a net gain of approximately $1 million, respectively, recognized upon disposition of certain inactive assets and impairments for assets taken out of service.

Interest Expense

Interest expense was $248 million for the year ended December 31, 2010, compared to $224 million and $196 million for the years ended December 31, 2009 and 2008, 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.

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The following table summarizes the components impacting the interest expense variance for the years ended December 31, 2010 and 2009 (in millions, except for percentages):

	$	Average LIBOR Rate	Weighted Average Interest Rate (1)
Interest expense for the year ended December 31, 2008	$ 196	2.7%	5.9%
Impact of retirement of senior notes (2)	(7)		
Impact of issuance of senior notes (3)	53		
Impact of decreased borrowings under credit facilities (4)	(15)		
Impact of decreased capitalized interest	2		
Other	(5)		
Interest expense for the year ended December 31, 2009	$ 224	0.3%	6.0%
Impact of retirement of senior notes (5)	(21)		
Impact of issuance of senior notes (6)	48		
Other	(3)		
Interest expense for the year ended December 31, 2010	$ 248	0.3%	5.3%

(1) Excludes commitment and other fees.

(2) In August 2009, our outstanding $175 million 4.75% senior notes due 2009 matured and were paid. In October 2009, we redeemed our outstanding $250 million 7.13% senior notes due 2014.

(3) In April, July and September 2009 we completed the issuances of $350 million of 8.75% senior notes due 2019, $500 million of 4.25% senior notes due 2012 and $500 million of 5.75% senior notes due 2020, respectively. A fluctuating portion of the 4.25% senior notes due 2012 is utilized to fund hedged inventory and would be classified as short-term debt if such activities were funded through our credit facilities. 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 profits as we consider interest on these borrowings a direct cost to storing the inventory. The costs applicable to the portion of the $500 million of 4.25% senior notes that was recognized within purchases and related costs was approximately $4 million and $1 million for the years ended December 31, 2010 and 2009, respectively.

(4) The change primarily reflects varying borrowing requirements for inventory-related borrowings and other working capital items and changes in London Interbank Offered Rate (LIBOR). As further discussed below, we utilized a portion of our $500 million 4.25% senior notes due 2012 in 2009 to fund our hedged inventory requirements. Therefore, we were able to reduce our short-term debt borrowing since such activities were not solely funded on our credit facilities.

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

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

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 $17 million, $11 million and $21 million for the years ended December 31, 2010, 2009 and 2008, respectively.

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Other Income, Net

Other income, net for the year ended December 31, 2010, 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, net for the year ended December 31, 2009, primarily included (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

Our income tax expense/benefit decreased by $7 million from an expense of $6 million in 2009 to a benefit of $1 million in 2010. In the years prior to 2010, 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. The fluctuations in income tax expense for each of the three years in the period ended December 31, 2010, has primarily been driven by the level of taxable earnings in our entities subject to Canadian federal and provincial taxes. We restructured our Canadian investment on January 1, 2011 and as of this date, all of our Canadian operations are conducted within corporate entities and are subject to Canadian federal and provincial taxes. As a result of this change, we expect that our income tax expense will increase in 2011 as compared to historical periods. See Note 7 to our Consolidated Financial Statements for further discussion.

Outlook

During 2008 and 2009, worldwide financial markets were extremely volatile and the global economy substantially weakened. The U.S. government and governments around the world took significant actions in response, including an attempt to provide liquidity and stability to the financial markets by providing government assistance to some of the largest financial institutions in the world. Although it appears that these collective actions have been successful in stabilizing the financial markets, we continue to maintain a cautious outlook for the overall economic environment. Certain data points observed in 2010 and recently signal improvements in the health of the economy have started to occur, while other data points indicate that we have yet to begin a sustainable recovery. For example, one indicator of the strength and velocity of the economy that also has an influence on our business is energy consumption. U.S. demand for petroleum has increased slightly from an average of 18.7 million barrels per day during 2009 to an average of 19.1 million barrels per day for the twelve months ended October 2010; however, it remains approximately 8% below the levels experienced during the 2005 to 2007 time period. Natural gas demand, which in 2009 had declined approximately 2% relative to 2008, has increased from an average of 62.6 Bcf per day in 2009 to an average of 64.9 Bcf per day for the twelve months ended October 2010.

Although we have seen a slight increase in U.S. energy consumption (i.e., demand), we believe the U.S. economy will remain relatively weak and that the pace of an economic recovery will be slow. We expect that the U.S. economy will ultimately rebound and energy demand will return to a growth profile; however, uncertainty around the timing of these events remains and the potential exists for further weakness in the economy or capital markets. Our business strategy is designed to manage a volatile environment and we believe that our asset base strategically positions us to benefit from certain of these developments.

On the supply side of our business, we are currently experiencing favorable fundamentals related to increasing crude oil production as well as changing crude oil flows, which has led to increased demand for our services across our operating segments. We believe that the continued development of major resource plays and the impact such production will have on the liquids distribution system will create additional opportunities for us to optimize the use of our existing assets as well as develop additional infrastructure to meet the needs of our customers.

There can be no assurance that these opportunities will come to fruition or that we will not be negatively affected by potential volatility or challenging capital markets conditions, or that our acquisition and expansion efforts will be successful. See Item 1A. Risk Factors - Risks Related to Our Business.

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Liquidity and Capital Resources

General

The primary sources of liquidity are our cash flow from operations as further discussed below in the section entitled Cash Flow from Operations and 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, interest payments on our outstanding debt and distributions to our unitholders and General Partner, (ii) maintenance and expansion activities, (iii) acquisitions of assets or businesses and (iv) repayment of principal on our long-term debt. 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 cash flows from operations, borrowings under our credit facilities, and/or the issuance of additional equity or debt securities. As of December 31, 2010, we had a working capital surplus of approximately $166 million, including cash and cash equivalents of $36 million and restricted cash of $20 million. We had approximately $877 million of liquidity available to meet our ongoing operational, investing and finance needs as of December 31, 2010 as noted below (in millions):

		As of December 31, 2010
Availability under PAA senior unsecured revolving credit facility	$	701
Availability under PAA senior secured hedged inventory facility		
Availability under PNG senior unsecured revolving credit facility (1)		140
Cash and cash equivalents		36
Total	$	877

(1) In April 2010, PNG entered into a three year, $400 million senior unsecured revolving credit facility that matures in May 2013. Borrowing capacity under this facility may be limited from time to time due to covenant limitations. See Note 4 to our Consolidated Financial Statements for additional discussion of this credit facility and the *Noncontrolling Interests in a Subsidiary* section of Note 5 for additional discussion regarding PNG.

We entered into a number of transactions in the first quarter of 2011 that impacted our liquidity. In January 2011, we expanded our liquidity through a $600 million senior note offering and by entering into a $500 million 364-day senior unsecured credit facility (See Credit Facilities and Indentures below). In addition, we redeemed our 7.75% senior notes that were maturing in 2012 for approximately $222 million. PNG also completed the $746 million acquisition of SG Resources Mississippi, LLC (the Southern Pines Acquisition) and issued approximately 17.4 million PNG common units to third parties for net proceeds of approximately $370 million (See Notes 3 and 5 of our Consolidated Financial Statements). The net impact of these transactions increased our liquidity by approximately $500 million. Giving effect to these transactions, our available liquidity as of December 31, 2010 of approximately $877 million would have increased to approximately $1.4 billion.

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.

Congress recently enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), which includes provisions regarding the use of derivative financial instruments. The scope and applicability of these provisions is not entirely clear and regulations implementing all the various aspects of the Dodd-Frank Act have not yet been issued. Our current assessment is that we may have additional documentation requirements. We will continue to monitor the final rules and regulations as they develop.

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

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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, 2010 was approximately $259 million. 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 2010, we increased the amount of our inventory. The increase in inventory was due to both increased volumes and prices and was primarily related to (i) our crude oil contango market storage activities and (ii) our LPG activities. The net increased levels of inventory were financed through borrowings under our credit facilities as well as through our $500 million senior notes that are being used to supplement capital available from our hedged inventory facility resulting in a negative impact to our operating cash flow for the period.

Net cash flows provided by operating activities for the twelve months ended December 31, 2009 and 2008 were approximately $365 million and $857 million, respectively. During 2009, we increased the amount of our inventory. The increase was due to both increased volumes and prices and was primarily related to our crude oil storage 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. During 2008, we also increased the amount of our inventory; however, these volumetric increases were offset by lower prices for our inventory stored at the end of the year compared to prior years. The net proceeds received during the year were used to repay borrowings under our credit facilities and favorably impacted our cash flow from operating activities.

Credit Facilities and Indentures

PAA Senior Unsecured Revolving Credit Facility. At December 31, 2010, we had approximately $701 million of available borrowing capacity under our $1.6 billion committed revolving credit facility. Of the capacity we utilized at December 31, 2010, approximately $75 million was associated with outstanding letters of credit and the remainder was borrowed. The majority of these borrowings relate to funding short term inventory purchases of LPG and crude oil. This credit facility has a maturity date of July 2012, contains no material adverse change language, and can be expanded to $2.0 billion, subject to additional lender commitments.

PAA Senior Secured Hedged Inventory Facility. In October 2010, we renewed our 364-day committed hedged inventory credit facility, which matures in October 2011. The facility has a borrowing capacity of $500 million, which may be increased to $1.2 billion, subject to obtaining additional lender commitments. This facility is a committed working capital facility, which is used to finance (i) the purchase of hedged crude oil inventory for storage activities and (ii) foreign import activities. Borrowings under the hedged inventory facility are collateralized by the inventory purchased under the facility and the associated accounts receivable, and will be repaid with the proceeds from the sale of such inventory. At December 31, 2010, we had no availability under our $500 million committed hedged inventory facility.

PNG Senior Unsecured Revolving Credit Facility. In April 2010, our consolidated subsidiary PNG entered into a three year, $400 million senior unsecured revolving credit facility that matures in May 2013. This credit facility, which bears interest based on LIBOR plus an applicable margin (as defined by the credit agreement), may be expanded to $600 million, subject to additional lender commitments and with approval of the administrative agent for the credit facility. At December 31, 2010, borrowings of approximately $260 million were outstanding under this facility. 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.

PAA 364-Day Credit Agreement. In January 2011, we entered into a 364-day senior unsecured credit facility with

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an aggregate borrowing capacity of $500 million. This credit facility has a maximum debt coverage ratio of 4.75 to 1.00 (5.50 to 1.00 during an acquisition period) and matures in January 2012. Borrowings under this facility may be used for any partnership purpose, including financing the Southern Pines Acquisition. See Notes 3 and 5 to our Consolidated Financial Statements for discussion regarding this acquisition.

Indentures. In January 2011, we issued $600 million of 5.00% senior notes due 2021 for net proceeds of approximately $592 million. Including these notes, we have several issues of senior debt outstanding at December 31, 2010 that total approximately $5.0 billion, excluding premium or discount, and range in size from $150 million to $600 million and mature at various dates beginning in 2012 through 2037.

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, foreign import 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). As of December 31, 2010, we have $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 July 2010 offering of our $400 million senior notes due September 15, 2015 and our November 2010 equity offering for net proceeds of approximately $296 million were both conducted under the WKSI Shelf. Also, our more recent debt offering completed in January 2011 for net proceeds of approximately $592 million was also conducted under the WKSI Shelf.

PAA Equity Offerings. We completed equity offerings during 2010, 2009 and 2008 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**	
2010	4,780,000	$	296
2009	11,040,000	$	456
2008	6,900,000	$	315

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. PNG additionally completed a private placement of 17.4 million common units to third parties for net proceeds of approximately $370 million in conjunction with the Southern Pines Acquisition in February 2011. In addition, we purchased approximately 10.2 million PNG common units for approximately $230 million, including our proportionate general partner contribution of $12 million. As a result of these transactions, 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).

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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
2008	6.5% Senior Notes issued at 99.424% of face value	May 2018	$	600	$	597

(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 (in conjunction with the early redemption of these notes, we recognized a loss of $23 million).

(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 (in conjunction with the early redemption of these notes, we recognized a loss of approximately $6 million).

(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.

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

We use cash primarily 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 for 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.

2011 Capital Expansion Projects. We expect the majority of funding for our 2011 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 2011 capital expansion program includes the following projects with the estimated cost for the entire year (in millions):

Projects		**2011**
PAA Natural Gas Storage (multiple projects)	$	103
Cushing Terminal Phases IX - XI		62
Basile gas processing facility		36
Shafter Expansion		30
Stanley Rail Project		25
Bumstead Facility		21
Mid-Continent project		17
Nipisi Treater		17
Patoka Phase IV		17
Undisclosed		17
Sidney Propane Storage		13
Basin System expansion		11
Other projects (1)		181
Total Projected Capital Expansion Projects	$	550

(1) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2010.

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Distributions to unitholders, general partner and noncontrolling interests. 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, 2011, we paid a quarterly distribution of $0.9575 per limited partner unit. This distribution represented a year-over-year distribution increase of approximately 3.2%. Additionally, we have paid $10 million and $2 million for distributions to our noncontrolling interests for December 31, 2010 and 2009, respectively. 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 distribution thresholds.

Upon closing of the Pacific, Rainbow and PNGS acquisitions, our general partner agreed to reduce the amounts due it as incentive distributions. See Note 5 to our Consolidated Financial Statements for details related to the general partner s incentive distribution reductions.

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

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. 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.

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, 2010 (in millions):

	2011	2012	2013	2014	2015	2016 and Thereafter	Total
	$ 274	$ 963	$ 740	$ 214	$ 754	$ 4,398	$ 7,343

Long-term debt and interest payments (1)							
Leases (2)	77	62	40	27	20	277	503
Other obligations (3)	69	66	29	4	3	46	217
Subtotal	420	1,091	809	245	777	4,721	8,063
Crude oil, refined products and LPG purchases (4)	4,070	383	278	227	182	132	5,272
Total	$ 4,490	$ 1,474	$ 1,087	$ 472	$ 959	$ 4,853	$ 13,335

(1) Includes debt service payments, interest payments due on our senior notes and the commitment fee on our revolving credit facilities. Although there is an outstanding balance on our revolving credit facilities at December 31, 2010, 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) storage, (ii) rights-of-way, (iii) office rent, (iv) pipeline assets and (v) trucks used in our gathering activities.

(3) Excludes a non-current liability of less than $1 million related to derivative activity included in crude oil and LPG purchases.

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(4) Amounts are based on estimated volumes and market prices based on average activity during December 2010. 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, 2010 and 2009, we had outstanding letters of credit of approximately $75 million and $76 million, respectively. The change in the value of outstanding letters of credit is impacted primarily by the fluctuation of market prices and the timing of foreign cargo purchases.

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, 2010 (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%	$ 103	$	$ 59
White Cliffs Pipeline, LLC	Crude Oil Pipeline	34%	$ 302	$ 5	$
Frontier Pipeline Company	Crude Oil Pipeline	22%	$ 28	$ 4	$
Butte Pipe Line Company	Crude Oil Pipeline	22%	$ 14	$ 2	$

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 primarily 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.

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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)	$ (107)	$ 107
Swaps and options contracts	(1)	$ (12)	$ 14
LPG and other:			
Futures contracts	(6)	$ (2)	$ 2
Swaps and options contracts (1)	(25)	$ (11)	$ 12
Total Fair Value	$ (46)		

(1) Amount includes a liability of approximately $2 million associated with LPG physical contracts not eligible for the normal purchase and normal sale scope exception under FASB guidance.

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 market risk due to the floating interest rates on our credit facilities. Therefore, from time to time we use interest rate derivatives to hedge interest 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 market risk. The majority of our variable rate debt at December 31, 2010, approximately $1.9 billion (including $300 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 1.4% is based upon rates in effect at December 31, 2010. The fair value of our interest rate derivatives is an unrealized gain of approximately $15 million as of December 31, 2010. A 10% increase in the forward LIBOR curve as of December 31, 2010 would result in a decrease of less than $1 million to the fair value of our interest rate derivatives. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates. 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, 2010. A 10% increase in the exchange rate (CAD-to-USD) would result in an decrease of approximately $4 million 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.

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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.

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, 2010. 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 2010 that has not previously been reported.

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PART III

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

Partnership Management and Governance

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

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

Our partnership agreement provides that our general partner will manage and operate us and that unitholders, unlike holders of common stock in a corporation, will have only limited voting rights on matters affecting our business or governance. The corporate governance of GP LLC is, in effect, the corporate governance of our partnership, subject in all cases to any specific unitholder rights contained in our partnership agreement. References to our Board of Directors mean the board of directors of GP LLC, which consists of eight directors elected by the members of GP LLC, and not by our unitholders. Under the Fifth Amended and Restated Limited Liability Company Agreement of GP LLC (the GP LLC Agreement), three of the members of GP LLC have the right to designate one director each, and our CEO is a director by virtue of holding the office. The remaining four seats are elected, and may be removed, by a majority of the membership interest. Directors filling three of these four at large seats must be independent. Under our current ownership profile, 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. For so long as Vulcan Inc. and its affiliates (Vulcan) hold in excess of 12 million of our common units, Vulcan Energy Corporation (Vulcan Energy) may send an individual (who must be a senior member of Vulcan s management) to attend board meetings in an observer capacity. If at any time after December 23, 2015 the number of common units held by Vulcan is less than 5% of our outstanding common units, we have the right to terminate 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 and its affiliates retained a substantial investment in PAA through their common unit holdings. 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 in all cases 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 enterprise-level risk 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 Managing Director 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.

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

Everardo Goyanes, the chairman of our audit committee, is Chairman of Liberty Natural Resources for Liberty Mutual Insurance Company, which is the parent of Liberty Energy Holdings, LLC (LEH). LEH makes investments in producing properties, from some of which Plains Marketing, L.P. buys the production. LEH does not operate the properties in which it invests. Plains Marketing pays the same amount per barrel to LEH that it pays to other interest owners in the properties. In 2010, the amount paid to LEH by Plains Marketing was approximately $1.3 million (net of severance taxes). The board has determined that the transactions with LEH do not compromise Mr. Goyanes independence.

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

Christopher M. Temple, a member of our audit committee, has no 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 2010. 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

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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 seven meetings, our audit committee had nine meetings, our compensation committee had two meetings and our governance committee had one meeting. All committee members 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*. Print versions of the foregoing are available to any person without charge, upon request by writing to our Secretary, Plains All American Pipeline, L.P., 333 Clay Street, Suite 1600, Houston, Texas 77002. We intend to disclose any amendment to or waiver of the Code of Ethics for Senior Financial Officers and any waiver of our Code of Business Conduct on behalf of an executive officer or director either on our Internet website or in an 8-K filing. Our Chief Executive Officer submitted to the NYSE the most recent annual certification, without qualification, as required by Section 303A.12(a) of the NYSE s Listed Company Manual.

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

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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, 2010 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 12/31/10)	Position(1)
Greg L. Armstrong*(2)	52	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis*	53	President and Chief Operating Officer
Phillip D. Kramer*	54	Executive Vice President
John R. Rutherford*	50	Executive Vice President
Al Swanson*	46	Executive Vice President and Chief Financial Officer
W. David Duckett*	55	President Plains Midstream Canada
Mark J. Gorman*	56	Senior Vice President Crude Oil Operations and Business Development
Alfred A. Lindseth	41	Senior Vice President Technology, Process & Risk Management
John P. vonBerg*	56	Senior Vice President Commercial Activities
Stephen L. Bart	50	Vice President Operations of Plains Midstream Canada
Samuel N. Brown	54	Vice President Pipeline Business Development
Kevin L. Cantrell	50	Vice President Internal Audit
David Craig	53	Executive Vice President and Chief Financial Officer of Plains Midstream Canada
Ralph R. Cross	55	Vice President Corporate Development and Transportation Services of Plains Midstream Canada
A. Patrick Diamond	38	Vice President
Lawrence J. Dreyfuss	56	Vice President, General Counsel Commercial & Litigation and Assistant Secretary
Roger D. Everett	65	Vice President Human Resources
James B. Fryfogle	59	Vice President Refinery Supply
M.D. (Mike) Hallahan	50	Vice President Crude Oil of Plains Midstream Canada
Chris Herbold*	38	Vice President Accounting and Chief Accounting Officer
Jim G. Hester	51	Vice President Acquisitions
John Keffer	51	Vice President Terminals
Charles Kingswell-Smith	59	Vice President and Treasurer
Gregg McClement	42	Vice President Business Development LPG of Plains Midstream Canada
Mike Mikuska	42	Vice President Business Development of Plains Midstream Canada

Tim Moore*	53	Vice President, General Counsel and Secretary
Daniel J. Nerbonne	53	Vice President Engineering
John F. Russell	62	Vice President West Coast Projects

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Robert M. Sanford	61	Vice President Lease Supply
Scott Sill	48	Vice President LPG Operations of Plains Midstream Canada
Phil Smith	52	Vice President
Troy E. Valenzuela	49	Vice President Environmental, Health and Safety
Sandi Wingert	40	Vice President Accounting of Plains Midstream Canada
David E. Wright	65	Vice President
Everardo Goyanes	66	Director and Member of Audit** Committee
Gary R. Petersen	64	Director and Member of Compensation and Governance Committees
John T. Raymond(2)	40	Director and Member of Compensation Committee
Robert V. Sinnott(2)	61	Director and Member of Compensation** Committee
Vicky Sutil(2)	46	Director and Member of Compensation Committee
J. Taft Symonds	71	Director and Member of Audit and Governance** Committees
Christopher M. Temple	43	Director and Member of Audit Committee

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* 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, 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 Oxy, of which she is Senior Manager, Corporate Development. 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 of the Federal Reserve Bank of Dallas, Houston Branch, and National Oilwell Varco, Inc. Mr. Armstrong previously served as a director of BreitBurn Energy Partners, L.P. 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.

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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 Senior 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

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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.

Stephen L. Bart has served as Vice President 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 - 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. Kevin 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.

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 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.

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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 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.

Mike Mikuska has served as Vice President Business Development 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.

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.

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.

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, Scott performed the role of West Coast District Superintendent, overseeing an LPG isomerization/hydrotreating facility, salt cavern terminal, fractionation plant and various storage terminals. Scott brings over 20 years 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. Phil 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. Mr. Goyanes has been Chairman of Liberty Natural Resources since April 2009. 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 Master s 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 $2.5 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 VEC), 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. We believe that Mr. Raymond s experience with investment in and management of a variety of upstream and midstream assets and operations will provide 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 Senior Manager, Corporate Development, 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 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

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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, will provide to 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 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 2010, except as follows: Mr. Duckett was late in filing two Forms 4 in connection with the sale of 23,896 common units on June 4, 2010 and the sale of 18,300 common units on December 20, 2010. These transactions were reported on a Form 4 filed on February 11, 2011.

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Item 11. *Executive Compensation*

Compensation Committee Report

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

In fulfilling its oversight responsibilities, the compensation committee reviewed and discussed with management the compensation discussion and analysis contained in this Annual Report on Form 10-K. Based on those reviews and discussions, the compensation committee recommended to the board of directors that the compensation discussion and analysis be included in the Annual Report on Form 10-K for the year ended December 31, 2010 for filing with the SEC.

Robert V. Sinnott, *Chairman*
Gary R. Petersen

Compensation Committee Interlocks and Insider Participation

Messrs. Petersen and Sinnott currently serve on the compensation committee, and served on the compensation committee throughout 2010. Geoff McKay, a former director, served on the compensation committee for a portion of 2010. During 2010, none of the members of the committee was an officer or employee of us or any of our subsidiaries, or served as an officer of any company with respect to which any of our executive officers served on such company s board of directors. In addition, none of the members of the compensation committee are former employees of ours or any of our subsidiaries. Mr. Sinnott is associated with Kayne Anderson and its affiliates, with which we have relationships. Mr. McKay is associated with Vulcan Energy and its affiliates, with which we have relationships. See Item 13. Certain Relationships and Related Transactions, and Director Independence. Mr. Raymond and Ms. Sutil were appointed to the compensation committee in February 2011.

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 was eligible to participate in 2010, 2009 and 2008. 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 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. The entire economic burden of the Class B units is borne solely by Plains AAP, L.P. 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. As of February 14, 2011, approximately 50% of the outstanding Class B units granted in 2007 had been earned, approximately 37.5% of the Class B units granted in 2009 had been earned, and none of the Class B units granted in 2010 had been earned.

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 (January 1, 2017 for Class B units granted in 2010). 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 (January 1, 2017 for Class B units granted in 2010) or Plains AAP, L.P. elects not to timely exercise its call

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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, 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. Recipients of these   transaction/transition grants   included Messrs. Armstrong, Pefanis and Swanson. Such grants are 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. See Summary Compensation Table.

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 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, 2010, our annual distribution per common unit has grown at a compound annual rate of 7.0% and the total return realized by our unitholders for that period averaged approximately 17.5%. During this period, we have enjoyed a 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. Instead, when indicated as a result of adding new senior management members to keep pace with

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our overall growth, necessary salary adjustments are made to maintain hierarchical relationships between senior management levels and the new senior management members. Since the date of our initial public offering (or date of employment, if later) through December 31, 2010, Messrs. Armstrong and Pefanis have each received one salary adjustment, Mr. Duckett has received small salary adjustments in line with other Canadian personnel, Mr. vonBerg has received one salary adjustment 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 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. As a result, the current practice is for the CEO to submit to the compensation committee a preliminary draft of bonus recommendations with the amount for the CEO left blank. In the context of discussing and adjusting bonus amounts for other executives set forth in the preliminary draft, the committee and the CEO reach consensus on the appropriate bonus amount for the CEO. The preliminary draft is then revised to include any changes or adjustments, as well as an amount for the CEO, in the formal submittal to the compensation committee for review and recommendation to the board.

U.S. Bonus based on Adjusted EBITDA. Mr. vonBerg and certain other members of our U.S.-based senior management team are directly involved in activities that generate partnership earnings. These

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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 as performance thresholds are met for existing awards, additional long-term incentives are created. Thus, performance is rewarded by relatively greater frequency of awards and lack of performance by relatively lesser frequency of awards. Generally, we believe that a 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 175,500 were issued as of December 31, 2010 pursuant to individual restricted units agreements between Plains AAP, L.P. and certain members of management. As of December 31, 2010 our Named Executive Officers held 121,000 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 2010

At the beginning of 2010, we established four public goals with paraphrased versions of three of these goals overlapping with three of our five internal goals. As a result, we entered 2010 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 2010 capital program and set the stage for continued growth in 2011 and beyond;

3. Continue to pursue strategic and accretive acquisitions; and

4. Increase our annualized distribution level to $3.80 per unit by November 2010.

Our two internal qualitative goals included (i) the development and implementation of an optimal tax strategy/structure for our Canadian assets, and (ii) advancing multi-year programs and initiatives and prepare the organization for future growth.

In general, we substantially met or exceeded these six goals.

- Excluding the benefit of unforecasted acquisitions completed during the year, our adjusted EBITDA exceeded the high end of our original guidance for 2010;

- We timely and cost-effectively executed a $355 million expansion capital program, with delayed projects replaced by attractive new ones, and advanced and expanded our portfolio of organic growth projects, setting up a 2011 program of $550 million of high quality, solid return projects;

- We completed six acquisitions for aggregate consideration of approximately $410 million, which primarily consisted of pipeline and storage facilities that complemented our existing asset base and business activities;

- We increased our annualized distribution rate by 3.3% to $3.80 per common unit, while generating aggregate annual distribution coverage of approximately 111%;

- We initiated and completed the IPO of PNG, raising approximately $470 million of equity and debt proceeds and establishing a separate financing source for this entity with a significantly lower cost of equity capital;

- We developed, refined and implemented a strategy to optimize the tax structure of our Canadian operations, continued to expand, implement and develop our integrity management program and improved communication throughout the organization; and

- We raised approximately $700 million in both long-term debt and equity in two different transactions, renewed our $500 million hedged inventory facility and added a $500 million liquidity facility, both on favorable terms, and ended 2010 with a strong balance sheet, solid credit metrics and approximately $900 million of committed liquidity.

For 2010, the elements of compensation were applied as described below. Except as described below, no material additions or changes to these elements are contemplated for 2011.

Salary. No salary adjustments for Named Executive Officers were recommended or made in 2010. 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 2010 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 40% in annual bonus and 60% in quarterly bonus.

Long-Term Incentive Awards. Prior to 2010, the last full grant cycle of equity awards to Named Executive Officers occurred in 2007. The performance threshold for vesting in two-thirds of equity awards granted in 2007 has been met, and the third performance threshold of $4.00 is expected to be reached in 2012. Vesting under the 2007 awards is also subject to minimum service periods that extend to May 2011 and May 2012. Any of these phantom units that remain outstanding in May 2014 for which the performance thresholds have not been met will be forfeited.

Consistent with our policy of issuing new grants with extended time-vesting periods when attainment of the performance thresholds of existing grants has occurred or is anticipated in the near term, in 2010 the board of directors granted awards with a top performance threshold of $4.20 (annualized) distribution per common unit. These grants are intended to encourage continued growth and fundamental performance that will support future distribution growth. Phantom units granted in February 2010 will vest in respective one-third increments on the date on which we pay an annualized quarterly distribution of at least $3.90, $4.05 and $4.20 per common unit and the later of the May 2013, May 2014 and May 2015 distribution dates, respectively. Such awards have associated DERs that become payable in one-third increments upon achieving the referenced performance thresholds, without regard to the minimum service period. Phantom units granted in October 2010 will vest in 25% increments on the date on which we pay an annualized quarterly distribution of at least $3.90, $3.90, $4.05 and $4.20 per common unit and the later of the November 2012, May 2013, May 2014 and May 2015 distribution dates, respectively. Such awards have associated DERs that become payable 50%, 25% and 25% on the date on which we pay an annualized quarterly distribution of $3.90, $4.05 and $4.20, respectively. See Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table and Application of Compensation Elements.

Any of the 2010 phantom units that remain outstanding as of the May 2016 distribution date for which the performance thresholds have not been met will be forfeited. Upon vesting, the phantom units are payable on a one-for-one basis in common units. The 2010 awards included grants to our Named Executive Officers as follows: Mr. Armstrong, 180,000; Mr. Pefanis, 120,000; Mr. Swanson, 60,000; Mr. vonBerg, 54,000; Mr. Duckett, 75,000; and Mr. Rutherford, 100,000.

Transaction/Transition Grants. In September 2010, PAA entered into transaction/transition grant agreements with Messrs. Armstrong, Pefanis and Swanson, pursuant to which these individuals acquired 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 PAA in connection with PNG s IPO. Distribution equivalent rights, payable by PAA in cash, were also granted with respect to the phantom common units and phantom series A subordinated units.

The phantom units will vest and be payable as follows: (i) the phantom common units will vest 50% on May 5, 2011 and 50% on May 5, 2012, and be payable one-for-one by PAA in Common Units of PNG; (ii) the phantom series A subordinated units will vest in connection with the conversion of the Series A Subordinated Units into Common Units, and be payable one-for-one by PAA in Common Units of PNG; and (iii) the phantom series B subordinated units will vest in tranches of 20%, 21%, 15%, 22% and 22%, respectively, in connection with the conversion of the First through Fifth Tranches of 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 the Series B Subordinated Units. Any phantom series A subordinated units and any phantom series B subordinated units that have not vested as of December 31, 2018 will be automatically cancelled on such date. The number of phantom units of each class or series granted by PAA to Messrs. Armstrong, Pefanis and Swanson is as follows: Mr. Armstrong, 62,000 each of phantom common units, phantom series A subordinated units and phantom series B subordinated units; Mr. Pefanis, 42,000 each of phantom common units, phantom series A subordinated units and phantom series B subordinated units; and Mr. Swanson, 21,000 each of phantom common units, phantom series A subordinated units and phantom series B subordinated units.

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Other Compensation Related Matters

Equity Ownership in PAA. As of December 31, 2010, 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, 2010, our Named Executive Officers beneficially owned, in the aggregate, approximately 889,000 of our common units (excluding any unvested equity awards), an approximately 2.4% indirect ownership interest in our general partner and IDRs, and 121,000 Class B units of Plains AAP, L.P. Based on the market price of our common units at December 31, 2010 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 2010.

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

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

Change in Control Triggers. The employment agreements for Messrs. Armstrong and Pefanis, the long-term incentive plan grants to our Named Executive Officers, and the Class B restricted units agreements include severance payment provisions or accelerated vesting triggered upon a change of control, as defined in the respective agreement. In the case of the long-term incentive plan grants 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.

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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. 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 four other most highly compensated executive officers in 2010 (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). Mr. Rutherford joined PAA on October 1, 2010. Therefore, his salary and bonus amounts reflect a partial year of payment.

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)(1)	All Other Compensation ($)(2)	Total ($)
Greg L. Armstrong	2010	375,000	3,250,000	5,868,436	15,900	9,509,336
Chairman and CEO	2009	375,000	3,000,000		15,800	3,390,800
	2008	375,000	2,900,000		14,775	3,289,775
Harry N. Pefanis	2010	300,000	3,100,000	3,946,511	15,900	7,362,411
President and Chief Operating Officer	2009	300,000	2,900,000		15,800	3,215,800

	2008	300,000	2,800,000		14,775	3,114,775
Al Swanson	2010	250,000	1,100,000	1,973,255	15,900	3,339,155
Executive Vice President and	2009	250,000	1,000,000	376,483	15,763	1,642,246
Chief Financial Officer	2008	180,000				