PLAINS ALL AMERICAN PIPELINE LP
Form 10-K
February 26, 2010
Table of Contents

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, 2009
	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 $4.8 billion on June 30, 2009, based on $42.55 per unit, the closing price of the Common Units as reported on the New York Stock Exchange on such date.

At February 22, 2010, there were outstanding 136,135,988 Common Units.

DOCUMENTS INCORPORATED BY REFERENCE

NONE

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

FORM 10-K 2009 ANNUAL REPORT

Table of Contents

		Page
	PART I	
Items 1 and 2.	Business and Properties	4
Item 1A.	Risk Factors	36
Item 1B.	Unresolved Staff Comments	51
Item 3.	Legal Proceedings	51
Item 4.	Submission of Matters to a Vote of Security Holders	54
	PART II	
Item 5.	Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities	55
Item 6.	Selected Financial Data	56
Item 7.	Management s Discussion and Analysis of Financial Condition and Results of Operations	59
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	79
Item 8.	Financial Statements and Supplementary Data	80
Item 9.	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	80
Item 9A.	Controls and Procedures	81
Item 9B.	Other Information	81
	PART III	
Item 10.	Directors and Executive Officers of Our General Partner and Corporate Governance	82
Item 11.	Executive Compensation	93
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters	110
Item 13.	Certain Relationships and Related Transactions, and Director Independence	115
Item 14.	Principal Accountant Fees and Services	120
	PART IV	
Item 15.	Exhibits and Financial Statement Schedules	121

Table of Contents

FORWARD-LOOKING STATEMENTS

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements 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 power supplies, materials or labor;
- the availability of adequate third-party production volumes for transportation and marketing in the areas in which we operate and other factors that could cause declines in volumes shipped on our pipelines by us and third-party shippers, 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 and fluctuations in tariffs or volumes on third-party pipelines;

- increased costs or lack of availability of insurance;

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

- the currency exchange rate of the Canadian dollar;

Table of Contents

- 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 deteriorated 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, we, us, our, ours and similar terms refer to Plains All American Pipeline, L.P. and its subsidiaries.

We are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products. We refer to liquefied petroleum gas and other natural gas-related petroleum products collectively as LPG. We are also engaged in the development and operation of natural gas storage facilities.

Our business activities are conducted through three segments: Transportation, Facilities and Supply and Logistics. We previously referred to the Supply and Logistics segment as the Marketing segment. We revised the segment name to better describe the business activities conducted within that segment.

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 13 holders, with four of these holders owning an aggregate interest of 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.).

Table of Contents

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

Partnership Structure

(1) Based on Form 4 filings for executive officers and directors, 13D filings for Paul G. Allen and Richard Kayne and other information believed to be reliable for the remaining investors, this group, or affiliates of such investors, owns approximately 25 million limited partner units, representing approximately 18% 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, PMC (Nova Scotia) Company, Plains Marketing Canada, L.P., PAA Natural Gas Storage, LLC (PNGS) 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) and Frontier Pipeline Company (Frontier).

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.

Table of Contents

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 of crude oil, refined products and LPG transportation, terminalling, storage and supply and logistics assets and businesses 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 believe PNGS s natural gas storage assets are also well-positioned to benefit from long-term industry trends and opportunities. PNGS s growth strategies are to develop and implement internal growth projects and to selectively pursue strategic and accretive 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. We intend to maintain a credit profile that we believe is consistent with an investment grade credit rating. We have targeted a general credit profile with the following attributes:

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

- an average long-term debt-to-adjusted EBITDA multiple of approximately 3.5x (adjusted EBITDA is earnings before interest, taxes, depreciation and amortization, equity compensation plan charges, gains and losses from derivative activities and selected items that are generally unusual or non-recurring);

- 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 and LPG. The crude oil, refined products and LPG purchased in these transactions are hedged. We do not consider the working capital borrowings associated with this activity to be part of our long-term capital structure. These borrowings are self-liquidating as they are repaid with sales proceeds. We also incur short-term debt for New York Mercantile Exchange (NYMEX) and IntercontinentalExchange (ICE) margin requirements.

In order for us to maintain our targeted credit profile and achieve growth through internal growth projects and acquisitions, we intend to fund at least 50% of the capital requirements associated with these activities with equity and cash flow in excess of distributions. From time to time, we may be outside the parameters of our targeted credit profile as, in

Table of Contents

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.

Credit Rating

As of February 2010, our senior unsecured ratings with Standard & Poor s Ratings Services and Moody s Investors Service were BBB-, stable outlook, and Baa3, stable outlook, respectively, both of which are considered investment grade ratings. We have targeted the attainment of stronger investment grade ratings of mid to high-BBB and Baa categories for Standard & Poor s and Moody s, respectively. However, our current ratings might not remain in effect for any given period of time, we might not be able to attain the higher ratings we have targeted and one or both of these ratings might be lowered or withdrawn entirely by the rating agencies. Note that a credit rating is not a recommendation to buy, sell or hold securities, and may be revised or withdrawn at any time. See Item 1A. Risk Factors Risks Related to Our Business Loss of credit rating or the ability to receive open credit could negatively affect our ability to use the counter-cyclical aspects of our asset base or to capitalize on a volatile market for discussion of the potential impacts of a downgrade in our credit ratings.

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 counter-cyclically balanced.* We believe the variety of activities executed within our supply and logistics segment provides us with a counter-cyclical balance that generally affords us the flexibility (i) to maintain a base level of margin irrespective of crude oil market conditions and (ii), in certain circumstances, to realize incremental margin during volatile market conditions.

- *Natural gas storage provides diversifying growth to fee-based business*. This business is underpinned by long term capacity contracts serviced by two facilities including the Pine Prairie facility. Expansion activity at the Pine Prairie facility will enable us to benefit from anticipated long-term growth in demand for natural gas storage capacity in North America.

• *We have the evaluation, integration and engineering skill sets and the financial flexibility to continue to pursue acquisition and expansion opportunities.* Over the past twelve years, we have completed and integrated 59 acquisitions with an aggregate purchase price of approximately $6.4 billion. We have also implemented internal expansion capital projects totaling approximately $2.1 billion. In addition, we believe we have resources to finance future strategic expansion and acquisition opportunities. As of December 31, 2009, we had approximately $950 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 25 years industry experience, and an average of 16 years with us or our predecessors and affiliates. In addition, through their ownership of common units, indirect interests in our general partner, grants of phantom units and the Class B units in Plains AAP, L.P., our management team has a vested interest in our continued success.

Acquisitions

The acquisition of assets and businesses that are strategic and complementary to our existing operations constitutes an integral component of our business strategy and growth objective. Such assets and businesses include crude oil related assets, refined products assets, LPG assets and natural gas storage assets, as well as other energy transportation related assets

Table of Contents

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 $50 million that we have completed over the past five years (in millions):

Acquisition	**Date**	**Description**		**Approximate Purchase Price**
Southcap Pipe Line Co. (Southcap)	Dec-2009	An additional 21% undivided joint interest in the Capline Pipeline System (Capline) and additional tankage (1)	$	62
PAA Natural Gas Storage, LLC	Sep-2009	Remaining 50% interest in PNGS	$	215(2)
Rainbow Pipeline Company (Rainbow)	May-2008	Crude oil gathering and transportation assets in Alberta, Canada	$	687
Tirzah Storage Facility	Oct-2007	Liquefied Petroleum Gas storage facility	$	54
Bumstead Storage Facility	Jul-2007	Liquefied Petroleum Gas storage facility	$	52
Pacific Energy Partners LP (Pacific)	Nov-2006	Merger of Pacific Energy Partners with and into the Partnership	$	2,456
El Paso to Albuquerque Products Pipeline Systems	Sep-2006	Three refined products pipeline systems	$	66
CAM/BOA/HIPS Crude oil systems	Jul-2006	60% interest in the Clovelly-to-Meraux (CAM) Pipeline system; 100% interest in the Bay Marchand-to-Ostrica-to-Alliance (BOA) system and various interests in the High Island Pipeline System (HIPS(3))	$	130
Andrews Petroleum and Lone Star Trucking (Andrews)	Apr-2006	Isomerization, fractionation, marketing and transportation services	$	220
South Louisiana Gathering and Transportation Assets	Apr-2006	Crude oil gathering and transportation assets, including inventory and related contracts in South Louisiana	$	129
Investment in Natural Gas Storage Facilities	Sep-2005	50% interest in PNGS	$	125

(1) We acquired our initial 22% undivided joint interest in the Capline Pipeline System in March 2004.

(2) In connection with the PNGS acquisition we consolidated and subsequently refinanced approximately $450 million of previously non-recourse joint venture debt. See Note 3 to our Consolidated Financial Statements for additional discussion regarding the PNGS acquisition.

(3) We relinquished our interest in HIPS in November 2006.

2009 Acquisitions

PNGS Acquisition

On September 3, 2009, we acquired the remaining 50% indirect interest in PNGS for an aggregate purchase price of $215 million (PNGS Acquisition). See Note 3 to our Consolidated Financial Statements for additional discussion regarding the PNGS acquisition. As a result of the transaction, we now own 100% of PNGS s natural gas storage business and related operating entities, which are accounted for on a consolidated basis beginning in September 2009. We historically accounted for our 50% indirect interest in PNGS under the equity method. We recorded a net gain of approximately $9 million, recorded in other income, in connection with (i) adjusting our previously owned 50% investment in PNGS to fair value and (ii) terminating an agreement to supply natural gas to PNGS.

PNGS currently owns and operates two natural gas storage facilities located in Louisiana and Michigan that have an aggregate working gas storage capacity of 40 billion cubic feet (Bcf) and an aggregate peak injection and withdrawal capacity of 1.7 Bcf per day and 3.2 Bcf per day, respectively. PNGS also leases storage capacity and pipeline transportation capacity from third parties from time to time in order to increase its operational flexibility and enhance the services it offers its customers. As of December 31, 2009, PNGS had 3 Bcf of storage capacity under lease from third parties and had secured the right to 379 MMcf per day of firm transportation service on various pipelines. Substantially all of PNGS s revenues are derived from the provision of firm storage services under multi-year, fee-based contracts. The gas storage operations are reflected in our facilities segment.

Table of Contents

Other Acquisitions

During 2009, we completed six additional acquisitions for aggregate consideration of approximately $178 million. These included an additional 21% undivided joint interest in Capline and associated tankage, as well as various crude oil pipelines and pipeline systems that are all included within our transportation segment. We also acquired a natural gas processing business, a refined products terminal and various crude oil storage tanks and other related assets that are all included within our facilities segment. The goodwill associated with such acquisitions was approximately $24 million. Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Acquisitions and Internal Growth Projects Acquisitions and see Note 3 to our Consolidated Financial Statements for further discussion of our acquisitions.

Ongoing Acquisition Activities

Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase of assets and operations that are strategic and complementary to our existing operations. Such assets and operations include crude oil, refined products, LPG and natural gas storage related assets. In addition, we have in the past evaluated and pursued, and intend in the future to evaluate and pursue, other energy related assets that have characteristics and opportunities similar to these business lines and enable us to leverage our asset base, knowledge base and skill sets. Such acquisition efforts may involve participation by us in processes that have been made public and involve a number of potential buyers, commonly referred to as auction processes, as well as situations in which we believe we are the only party or one of a limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets which, if acquired, could have a material effect on our financial condition and results of operations. Even after we have reached agreement on a purchase price with a potential seller, confirmatory due diligence or negotiations regarding other terms of the acquisition can cause discussions to be terminated. Accordingly, we typically do not announce a transaction until after we have executed a definitive acquisition agreement. Although we expect the acquisitions we make to be accretive in the long term, we can provide no assurance that our expectations will ultimately be realized. See Item 1A. Risk Factors Risks Related to Our Business If we do not make acquisitions on economically acceptable terms, our future growth may be limited and Our acquisition strategy involves risks that may adversely affect our business.

Global Petroleum Market Overview

The United States comprises less than 5% of the world s population and generates only 11% of the world s petroleum production, but 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 and other liquid petroleum products) and is derived from the Energy Information Administration s (EIA) Annual Energy Outlook 2009 Early Release (see EIA website at *www.eia.doe.gov*).

Table of Contents

	2009 (1)	2010	Projected 2011	2015
		(In millions of barrels per day)		
Supply				
OECD (2)				
U.S.	9.0	9.1	9.4	10.0
Other	11.9	11.9	11.5	11.3
Total OECD	20.9	21.0	20.9	21.3
Organization of the Petroleum Exporting Countries	34.0	34.1	35.7	37.5
Other	29.3	30.8	30.6	32.2
Total World Production	84.2	85.9	87.2	91.0

	2009 (1)	2010	Projected 2011	2015
		(In millions of barrels per day)		
Demand				
OECD				
U.S.	18.7	19.2	19.8	20.2
Other	26.7	27.2	27.2	27.5
Total OECD	45.4	46.4	47.0	47.7
Other	38.7	39.5	40.2	43.2
Total World Consumption	84.1	85.9	87.2	90.9
Net World Production/(Consumption)	0.1			0.1
U.S. Production as % of World Production	11%	11%	11%	11%
U.S. Consumption as % of World Consumption	22%	22%	23%	22%
Net U.S. Consumption	(9.7)	(10.1)	(10.4)	(10.2)

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(1) The 2009 amounts are based on ten months of actual data and two months of data derived from a short-term energy model published by the EIA.

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

World economic growth is a driver of the world petroleum market. The challenging global economic climate has resulted in reduced demand and 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, after which refinery demand decreased to average approximately 14.5 million barrels per day for the 12 months ended October

Table of Contents

2009. Of this amount, only 5.2 million barrels per day was produced domestically. Accordingly, approximately 64% of the crude oil used by U.S. domestic refineries is imported. This imbalance represents a continuing 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, during 2008 and 2009 foreign crude imports slowed to 9.3 million barrels per day for the 12 months ended October 2009. 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 2009 column are based on the twelve months from November 2008 to October 2009.

	Actual		**Projected**	
	2009	**2010**	**2011**	**2015**
		(In millions of barrels per day)		
Supply				
Domestic Crude Oil Production	5.2	5.3	5.4	5.8
Net Imports - Crude Oil	9.3	8.8	9.1	8.9
Crude Oil Input to Domestic Refineries	14.5	14.1	14.5	14.7
Net Product Imports	0.4	1.2	1.3	1.2
Other - (NGL Production, Refinery Processing Gain)	3.8	3.9	4.0	4.3
Total Domestic Petroleum Consumption	18.7	19.2	19.8	20.2

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 2009 and is derived from information published by the EIA (see EIA website at *www.eia.doe.gov*) (in millions of barrels per day).

Petroleum Administration Defense District	**Regional Supply**	**Refinery Demand**	**Supply Shortfall**
PADD I (East Coast)	0.0	1.3	(1.3)
PADD II (Midwest)	0.6	3.2	(2.6)
PADD III (South)	3.0	7.0	(4.0)
PADD IV (Rockies)	0.3	0.5	(0.2)
PADD V (West Coast)	1.3	2.4	(1.1)
Total U.S.	5.2	14.4	(9.2)

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

Over the last 24 years, crude oil production in PADD II has declined from approximately 1.0 million barrels per day to approximately 600,000 barrels per day. Over this same time period, refinery demand has increased from approximately 2.7 million barrels per day in 1985 to 3.2 million barrels per day for the twelve months ended October 2009. As a result, the volume of crude oil transported into PADD II has increased approximately 47% in absolute terms or 1.6% annually from 1.7 million barrels per day to 2.6 million barrels per day. This aggregate shortfall is principally supplied by direct imports from Canada to the north and from the Gulf Coast area and the Cushing Interchange to the south.

Volatility in 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;

Table of Contents

- 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.

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 recent peak in 2005 of 20.8 million barrels, yielding an average annual increase of approximately 1.5%. Due to recent economic weakness, refined product demand has decreased to average approximately 18.7 million barrels per day for the twelve months ended October 2009. Given the decreased demand for refined products and resulting excess refining capacity, a number of U.S. refineries have reduced output and, in some cases, indefinitely closed. The EIA is currently forecasting growth in refined product demand to resume in 2010 and continue thereafter. We believe that this projected additional intermediate and long-term demand will be met primarily by increased utilization of available capacity as well as increased imports of refined products, the combination of which we believe will generate incremental 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.

Table of Contents

The complexity and volatility of the refined products market creates opportunities to solve the logistical inefficiencies 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.

Natural Gas Storage Market Overview

After treatment for impurities such as carbon dioxide and hydrogen sulfide and processing to separate heavier hydrocarbons from the gas stream, natural gas from one source generally is fungible with natural gas from any other source. Because of its fungibility and physical volatility and the fact that it is transported in a gaseous state, natural gas presents different logistical transportation challenges than crude oil and refined products.

Drivers of Demand for Storage. 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, 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 value of storage services.

Natural Gas Demand. According to the EIA, during the period from 1998 through 2008, natural gas consumption increased by 4.1% overall from an average of approximately 60.9 Bcf per day in 1998 to an average of approximately 63.4 Bcf per day in 2008. Although the change in consumption levels during this period was variable on a year-to-year basis, growth was highest in the seasonal and weather-sensitive power generation and commercial/residential sectors, where consumption grew by approximately 45.2% and 6.2%, respectively. The growth in these sectors was partially offset by an approximate 20.5% decline in gas consumption in the less seasonal industrial sector.

Despite the increased use of natural-gas fired generation during the summer cooling months, the seasonality of natural gas consumption has remained strong. According to EIA data, during the last decade, consumption during the winter months averaged approximately 40% more than consumption during the summer months.

Natural Gas Supply. For the majority of the last decade, domestic production has been relatively flat and has failed to keep pace with domestic consumption. Over the past few years, however, domestic production has been growing, primarily due to increases

Table of Contents

in production from developing shale resource plays. According to EIA data during the two-year period from January 1, 2007 through December 31, 2008, domestic production of natural gas increased by an average of approximately 5% per year and estimates of proved natural gas reserves increased by an average of approximately 7.5% per year, in each case largely due to continued development of shale resources. Beginning in 2007, leasing and development activities increased in a number of new shale resource plays, which in 2009 caused the EIA to significantly increase its outlook for domestic natural gas production. Notably, the typical production profile for shale production is short lived with initial high levels of production and steep declines thereafter. For this reason, and because producing gas from shale formations is generally more complex and expensive than conventional onshore production, it is difficult to predict future shale resource production levels with certainty.

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). In recent years, U.S. and Canadian LNG imports have averaged an aggregate of approximately 1 to 3 Bcf per day, while the total LNG import capacity of U.S. and Canadian infrastructure is approximately 16 Bcf per day. In addition, total worldwide liquefaction capacity for LNG has been increasing over the last several years and additional capacity is scheduled to come online over the next few years.

For the foreseeable future, we believe there will be ample supplies of natural gas from a combination of domestic production, pipeline imports and waterborne imports of LNG. We also believe, however, that it is difficult to predict the extent to which domestic production from shale resources and LNG imports will increase or decrease and that this source of supply uncertainty adds an element of volatility to natural gas markets that will drive greater demand for storage services, especially from well-positioned, high performance facilities that can provide customers with access to both LNG imports and shale production.

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.

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 and Settoon Towing, in which we own noncontrolling interests.

As of December 31, 2009, 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;
- 28 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;
- 84 trucks and 353 trailers; and
- 68 transport and storage barges and 39 transport tugs through our interest in Settoon Towing.

Table of Contents

Following is a tabular presentation of our active pipeline assets in the United States and Canada as of December 31, 2009, grouped by geographic location:

Region / Pipeline and Gathering Systems (1)	System Miles	2009 Average Net Barrels per Day (2) (in thousands)
Southwest US		
Basin	519	394
Other	3,601	484
Southwest US Subtotal	**4,120**	**878**
Western US		
All American	138	40
Line 63/Line 2000	428	131
Other	152	102
Western US Subtotal	**718**	**273**
US Rocky Mountain		
Salt Lake City Area Systems	708	131
Other	3,313	252
US Rocky Mountain Subtotal	**4,021**	**383**
US Gulf Coast		
Capline(3)	632	193
Other	943	290
US Gulf Coast Subtotal	**1,575**	**483**
Central US Subtotal	**2,546**	**362**
Domestic Total	**12,980**	**2,379**
Canada		
Rangeland	1,252	53
Rainbow	594	183
Manito	554	63
Other	635	158
Canada Total	**3,035**	**457**
Grand Total	**16,015**	**2,836**

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

(2) Represents average volumes for the entire year of 2009.

(3) Non-operated pipeline.

Southwest US

Basin Pipeline System. We own an approximate 87% undivided joint interest in and act as operator of the Basin Pipeline system. The Basin system is a primary route for transporting crude oil from the Permian Basin (in west Texas and southern New Mexico) to Cushing, Oklahoma, for further delivery to Mid-Continent and Midwest refining centers. The Basin system is a 519-mile mainline, telescoping crude oil system with a 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 394,000 barrels per day (attributable to our interest) during 2009.

Table of Contents

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 7 million barrels of tankage located along the system. The Basin system is subject to tariff rates regulated by the Federal Energy Regulatory Commission (FERC).

Western US

All American Pipeline System. We own a 100% interest in the All American Pipeline system. The All American Pipeline is a common carrier crude oil pipeline system that transports crude oil produced from certain outer continental shelf, or OCS, fields offshore California via connecting pipelines to refinery markets in California. The system extends approximately 10 miles along the California coast from Las Flores to Gaviota (24-inch diameter pipe) and continues from Gaviota approximately 128 miles to our station in Emidio, California (30-inch diameter pipe). Between Gaviota and our Emidio Station, the All American Pipeline interconnects with our San Joaquin Valley Gathering System, Line 2000 and Line 63, as well as other third party intrastate pipelines. The system is subject to tariff rates regulated by the FERC.

The All American Pipeline currently transports OCS crude oil received at the onshore facilities of the Santa Ynez field at Las Flores and the onshore facilities of the Point Arguello field located at Gaviota. ExxonMobil, which owns all of the Santa Ynez production, and Plains Exploration and Production Company and other producers that together own approximately 70% of the Point Arguello production, have entered into transportation agreements committing to transport all of their production from these fields on the All American Pipeline. These agreements provide for a minimum tariff with annual escalations based on specific composite indices. The producers from the Point Arguello field that do not have contracts with us have no other existing means of transporting their production and, therefore, ship their volumes on the All American Pipeline at the filed (or contracted) tariffs. For 2009, 2008 and 2007, tariffs on the All American Pipeline averaged $2.46 per barrel, $2.24 per barrel and $2.18 per barrel, respectively. The agreements do not require these owners to transport a minimum volume. These agreements include an annual one year evergreen provision that requires one year s advance notice to cancel.

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

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

	For the Year Ended December 31,				
	2009	2008	2007	2006	2005
Average daily volumes received from:					
Point Arguello (at Gaviota)	6	7	8	9	10
Santa Ynez (at Las Flores)	34	38	38	40	41
Total	40	45	46	49	51

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 115-mile trunk pipeline (of which 101 miles is 14-inch pipe and 14 miles is 16-inch pipe),

originating at our Kelley Pump Station in Kern County, California and terminating at our West Hynes Station in Long Beach, California. The trunk pipeline has a capacity of approximately 110,000 barrels per day. The Line 63 system includes 26 miles of distribution pipelines in the Los Angeles Basin, with a throughput capacity of approximately 144,000 barrels per day, and 188 miles of gathering pipelines in the San Joaquin Valley, with a throughput capacity of approximately 72,000 barrels per day. We also have 25 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 2009, combined throughput on Line 63 totaled an average of approximately 67,000 barrels per day.

Table of Contents

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 2009, throughput on Line 2000 averaged approximately 64,000 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 (including the Wahsatch pipeline discussed below) and storage tanks with a total storage capacity of approximately 1 million barrels. The trunk pipeline originates at Wamsutter, Wyoming and receives deliveries from local trucks and gathering systems and can deliver to Salt Lake City, Utah and Ft. Laramie, Wyoming. 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.

During the fourth quarter of 2008, construction was completed on the 94-mile expansion of the Salt Lake City Area system from the terminus of Frontier Pipeline to Salt Lake City, which has throughput capacity of 120,000 barrels per day and is referred to as the Wahsatch pipeline. This line was placed into service in the first quarter of 2009. Ten-year transportation contracts have been executed with four Salt Lake City refiners for service on this pipeline. In the first quarter of 2009, we executed an agreement in which we sold a 25% interest in this line to Holly Energy Partners-Operating, L.P. As part of this agreement, Holly Refining and Marketing Company also entered into a 10-year transportation agreement making it the fifth refinery to commit. Plains portion of the total project cost was approximately $228 million. For 2009, throughput on the Salt Lake City Area Systems in total averaged approximately 131,000 barrels per day.

US Gulf Coast

Capline Pipeline System. The Capline Pipeline system is a 632-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. In December 2009, we purchased an additional 21% undivided interest in the Capline Pipeline System. The assets purchased also included a 100% interest in 720,000 barrels of tankage at Patoka, Illinois. We acquired our initial 22% interest in Capline in 2004, and as a result of this transaction, we now have an aggregate undivided joint interest of 43%.

The Capline Pipeline system is one of the primary transportation routes for crude oil shipped into the Midwestern U.S., accessing approximately 3 million barrels of refining capacity in PADD II. Shell is the operator of this system 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 600,000-barrel tankers as well as access to the Louisiana Offshore Oil Port, it is a key transporter of sweet and light sour foreign crude to PADD II. Total system operating capacity is approximately 1 million barrels per day of crude oil, of which approximately 248,000 barrels per day were attributable to our interest during 2009. In connection with the purchase of our additional undivided interest in the system, our attributable interest has increased to approximately 470,000 barrels per day. Throughput on our interest averaged approximately 193,000 barrels per day during 2009.

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 592 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 via third-party pipeline connections or south to the U.S./Canadian border near Cutbank, Montana, where it connects to our Western Corridor system. Currently, MAPL originates in Edmonton, Alberta and terminates in Sundre, Alberta where it connects to the Rangeland Pipeline. We plan to reverse MAPL allowing for flow from Rangeland s Sundre terminal directly to Edmonton. During 2009, we acquired the Valley and Cremona pipeline systems which are included in the 660 miles of gathering pipeline. These acquisitions expanded our gathering system in central Alberta and bring us closer to providing single pipeline access to the Edmonton market. During 2009, Plains built and commissioned 240,000 barrels of tankage bringing our storage capability at Edmonton to 320,000 barrels. Total average throughput during 2009 on the Rangeland system was approximately 53,000 barrels per day.

Table of Contents

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 200,000 barrels per day and transported approximately 183,000 barrels per day during 2009.

Manito. We own a 100% interest in the Manito heavy oil system. This 554-mile system is comprised of the Manito pipeline, the North Sask pipeline and the Bodo/Cactus Lake pipeline. The North Sask pipeline is 84 miles in length and originates near Turtleford, Saskatchewan and terminates in Dulwich, Saskatchewan. The Manito pipeline includes 334 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. For 2009, approximately 63,000 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, 2009, we owned, operated and employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 51 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 40 Bcf of natural gas storage capacity; and
- approximately 9 Bcf of base gas in storage facilities owned by us;

- 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 22,500 barrels per day.

As of December 31, 2009, we were in the process of constructing approximately 7 million barrels of additional above-ground crude oil and refined product terminalling and storage capacities and an additional 31 Bcf of high-deliverability salt-cavern natural gas storage capacity.

Table of Contents

Following is a tabular presentation of our active facilities segment assets in the United States and Canada as of December 31, 2009, grouped by product type:

Facility	Capacity (in millions of barrels, except where noted)
Crude Oil and Refined Products	
Cushing	11
Kerrobert	1
LA Basin	10
Martinez and Richmond	5
Mobile and Ten Mile	3
Patoka	3
Philadelphia Area	4
St. James	6
Other	8
Subtotal	**51**
LPG	
Bumstead	2
Tirzah	1
Other	3
Subtotal	**6**
Natural Gas	
Pine Prairie	14 Bcf
Bluewater/Kimball	26 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 six separate expansion phases, which increased the capacity of the Cushing Terminal to a total of approximately 11 million barrels. 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. In 2008, we commenced a project at the Kerrobert terminal, which provides receipt access to heavy oil from the Enbridge system and increases delivery capacity while reducing third-party costs. The cost of the project is estimated to be approximately $42 million, of which approximately $33 million was incurred in 2009. The total storage capacity at the Kerrobert terminal is approximately 1 million barrels.

L.A. Basin. We own five crude oil and refined product storage facilities in the Los Angeles area with a total of 10 million barrels of storage capacity and a distribution pipeline system of approximately 70 miles of pipeline in the Los Angeles Basin. Approximately 9 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. The Los Angeles area system s pipeline distribution assets

Table of Contents

connect its storage assets with major refineries, our Line 2000 pipeline, and third-party pipelines and marine terminals in the Los Angeles Basin. The system is capable of loading and off-loading marine shipments at a rate of 25,000 barrels per hour and transporting the product directly to or from certain refineries, other pipelines or its storage facilities. In addition, we can deliver crude oil and feedstocks from our storage facilities to the refineries served by this system at rates of up to 6,000 barrels per hour.

Martinez and Richmond Terminals. We own two terminals in the San Francisco, California area: a terminal at Martinez (which provides refined product and crude oil service) and a terminal at Richmond (which provides refined product service). Our San Francisco area terminals 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 that can load between approximately 4,000 and 10,000 barrels per hour of refined products. There is also a rail spur at the Richmond terminal that is able to receive products by train.

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 half 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 3 million barrels of storage capacity and the associated manifold and header system at the Patoka Interchange located in southern Illinois. We anticipate Patoka to be a growing regional hub with access to domestic and foreign crude oil volumes moving north on the Capline system as well as Canadian barrels moving south. This project will have the ability to be expanded should market conditions warrant. 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 that can load approximately 10,000 to 12,000 barrels per hour of refined products and black oils (heavy crude oils). The Philadelphia area terminals also receive products from connecting pipelines and offer truck loading services.

St. James Terminal. We have approximately 6 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. During the fourth quarter of 2009, we also substantially completed construction of a marine dock that is able to receive both barges and tankers. We are currently able to receive barges and will bring the dock into full service for tankers during the first quarter of 2010. See Crude Oil Storage Facilities Under Construction and Under Development below for discussion of ongoing expansion activities at this facility.

Crude Oil Storage Facilities Under Construction and Under Development

Cushing Terminal & Mid-Continent Area. During 2009, we began construction on additional crude oil tankage at our Cushing Terminal. The project included the construction of approximately 2 million barrels of storage that is projected to be completed during 2010. This expansion is supported by long-term customer commitments. As of December 31, 2009, we have spent approximately $25 million towards this project out of a total estimated cost of approximately $42 million. In addition, late in 2009 we approved the construction of approximately 1 million barrels of storage capacity at our Cushing Terminal, which has an anticipated total cost of approximately $18 million, and another approximately 1 million barrels of storage capacity at our Wichita Falls, Texas facility at a cost of approximately $13 million. These expansions are expected to be completed in 2011 and are supported by long-term customer commitments.

Patoka & St. James Terminals and Dock. During 2009, we began construction on light-product storage tankage at the Patoka and St. James terminal locations. These projects will include the construction of 600,000 barrels of storage capacity

Table of Contents

at the Patoka terminal and 900,000 barrels of storage capacity at the St. James terminal. This new tankage will be completed in 2010 and complements the marine dock that is near completion at the St. James location. The cost of the project at the St. James terminal in aggregate is estimated to be approximately $132 million. Additionally, the expansion of our Patoka Terminal with approximately 800,000 barrels of additional storage capacity for crude oil service has been approved and will be completed in 2011 at an approximate cost of $28 million.

Pier 400. For a number of years, we or our predecessors have been involved in an effort 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.

In 2004, 2005 and 2007, we entered into or modified agreements with refiners in the Los Angeles Basin that provide long-term customer commitments to off-load a total of 200,000 barrels per day of crude oil at the Pier 400 dock. The agreements are subject to satisfaction of various conditions, such as the achievement of various progress milestones, financing, continued economic viability and completion of other ancillary agreements related to the project.

Due primarily to regulatory processes and delays, we did not meet certain project milestone dates and other economic conditions set forth in our agreements with our customers, and we could not meet certain key conditions in each of our agreements. As of the end of 2009, we have formally cancelled two of three agreements and are in the process of canceling a third agreement. We are in discussions with each of the three key customers and are working on developing new replacement agreements that reflect revised terms and conditions and a downsized initial project.

The project is subject to regulation by a number of state, local and federal agencies and regulatory bodies. The regulatory processes are complex and interrelated with our customer negotiations. These regulatory bodies include the Los Angeles Board of Harbor Commissioners, the South Coast Air Quality Management District, various departments of the City of Los Angeles, the Port of Los Angeles, the Los Angeles City Council and the U.S. Army Corps of Engineers. In addition, final construction of the Pier 400 project is subject to the completion and execution of a land lease (that may also require a dock construction agreement) with the Port of Los Angeles, satisfaction of environmental permit requirements and receipt of other approvals.

The project Environmental Impact Report (EIR) was approved by the Board of Harbor Commissioners of the Port of Los Angeles on November 20, 2008 and subsequently, through the denial of an appeal of the Harbor Commission action, by the Los Angeles City Council on April 15, 2009. On May 15, 2009 a Petition for Writ of Mandate alleging a violation of the California Environmental Quality Act (CEQA) and violation of the Los Angeles municipal code and charter was filed in the Los Angeles Superior Court against the City of Los Angeles, the Port of Los Angeles, the Los Angeles Board of Harbor Commissioners and Pacific L. A. Marine Terminal LLC (PLAMT). This issue was formally heard by the court on January 15, 2010 and a final ruling was issued in favor of the respondents on January 19, 2010. All remaining permits and legal agreements related to the project are expected to be finalized in 2010.

The estimated cost of the project has increased significantly during the regulatory approval process due to increased service and supply costs of the original project, changes in scope of the project to meet long-term objectives of the various regulatory bodies and incremental costs associated with adapting to environmental safeguards, requirements and protections required by the governing bodies. We have reduced the scope of the project and have completed an updated cost estimate for the Pier 400 project, and based on conditions existing in late 2009 we estimate that the project will cost approximately $445 million (plus, potentially, an amount for dock construction) to complete, including $76 million of costs associated with emission reduction credits and development and engineering costs incurred to date and $63 million of estimated capitalized interest to be incurred during the construction period. This estimate is subject to change depending on various factors, including the final scope of the project and the requirements imposed through the permitting process. This cost estimate assumes the construction of 1.5 million barrels of storage.

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 intend to begin upgrading and improving our Bumstead LPG storage facility, which will increase the capacity by approximately 700,000 barrels. This project is expected to be completed late in 2010 at a cost of approximately $17 million.

Table of Contents

Tirzah. The Tirzah facility is located in South Carolina and has an underground granite storage cavern with approximately 1 million barrels of 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 natural gas liquids (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 8,500 barrels per day.

Natural Gas Storage Facilities

Pine Prairie. As a strategically located, high-deliverability storage facility, Pine Prairie has attracted customers whose storage needs include both traditional seasonal storage services and short-term storage services. Pine Prairie is located northwest of Lafayette, Louisiana and is strategically positioned relative to several major market hubs, including:

- the Henry Hub, which is the delivery point for NYMEX natural gas futures contracts and is located approximately 50 miles to the southeast of Pine Prairie;
- the Carthage Hub in east Texas, which is located approximately 150 miles northwest of Pine Prairie; and
- the Perryville Hub in north Louisiana, which is located approximately 130 miles north of Pine Prairie.

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. This interconnectivity, combined with existing compression capacity and approximately 50 MMcf per day of leased third-party pipeline transportation capacity as of December 31, 2009, gives Pine Prairie the operational flexibility to receive from and deliver to multiple pipelines simultaneously.

Pine Prairie began commercial operations in October 2008 and currently has 14 Bcf of working gas storage capacity in two caverns, and planned expansions that will increase Pine Prairie s total capacity to 42 Bcf by mid-2012 and 45 Bcf by mid-2015, making it one of the largest high-deliverability salt-cavern natural gas storage facilities in North America. 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.

Bluewater. The Bluewater gas storage facility is located in the State of Michigan, which contains more natural gas storage capacity than any other state in the U.S., and primarily services seasonal storage needs throughout the Midwest and Northeast portions of the U.S. and the Southeast portion of Canada. Bluewater s 30-mile, 20-inch diameter pipeline header system is supported by 13,350 horsepower of compression and is connected to three interstate and three intrastate natural gas 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 10-year period beginning in 2011. 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. As of December 31, 2009, we had leased approximately 3 Bcf of additional capacity at third-party natural gas storage facilities as well as 329 MMcf per day of related pipeline transportation capacity.

Supply and Logistics Segment

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

Table of Contents

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

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

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

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

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

We believe that the majority of activities that are carried out within our supply and logistics segment are counter-cyclically balanced to produce a stable baseline of results in a variety of market conditions, while at the same time providing upside potential associated with opportunities inherent in volatile market conditions. These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies to provide a counter-cyclical balance. The tankage that is used to support our arbitrage activities positions us to capture margins in a contango market (when the oil prices for future deliveries are higher than the current prices) or when the market switches from contango to backwardation (when the oil prices for future deliveries are lower than the current prices). See Crude Oil Volatility; Counter-Cyclical Balance; Risk Management for further discussion.

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.

In addition to substantial working inventories associated with its merchant activities, as of December 31, 2009, 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:

- 10 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;

- 522 trucks and 630 trailers; and
- 1,473 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.

We purchase crude oil and LPG from multiple producers and believe that we have established long-term, broad-based relationships with the crude oil and LPG producers in our areas of operations. Supply and logistics activities involve relatively large volumes of transactions, often with lower overall margins than transportation and facilities operations. Supply and logistics activities for LPG typically consist of smaller volumes per transaction relative to crude oil.

The following table shows the average daily volume of our supply and logistics activities for the year ended December 31, 2009 (in thousands of barrels per day):

Table of Contents

	Volumes
Crude oil lease gathering purchases	612
Refined products sales	35
LPG sales	105
Waterborne foreign crude oil imported	55
Supply & Logistics activities total	807

Crude Oil and LPG Purchases. We purchase crude oil in North America from producers under contracts, the majority of which range in term from a thirty-day evergreen to three years. 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.

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 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. The majority of these contracts are at market price and have terms ranging from one month to three years. We sell LPG primarily to retailers and refiners, and limited volumes to other marketers. We establish a margin for 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.

Table of Contents

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

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

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

Crude Oil Volatility; Counter-Cyclical Balance; Risk Management

Crude oil commodity prices have historically been very volatile and cyclical, and continue to reflect such a trend. For example, over the last 23 years, NYMEX West Texas Intermediate crude oil benchmark prices have ranged from a low of approximately $10 per barrel during March 1986 to a high of over $147 per barrel during July 2008. 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 affected during 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.

Counter-Cyclical Balance

During periods when supply exceeds the demand for crude oil in the near term, the market for crude oil is often in contango, meaning that the price of crude oil for future deliveries is higher than current prices. A contango market generally has a negative impact on our lease gathering margins, but is favorable to our commercial strategies that are associated with storage tankage leased from the facilities segment or from third parties. Those who control storage at major trading locations (such as the Cushing Interchange) can simultaneously purchase production at current prices for storage and sell forward at higher prices for future delivery.

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

The periods between a backwardated market and a contango market are referred to as transition periods. Depending on the overall duration of these transition periods, how we have allocated our assets to particular strategies and the duration of our crude oil purchase and sale contracts and storage lease agreements, these transition periods may have either an adverse or beneficial effect on our aggregate segment profit. A prolonged transition from a backwardated market to a contango market, or vice versa (essentially a market that is neither in pronounced backwardation nor contango), represents the most difficult environment for our supply and logistics segment. When the market is in contango, we will use our tankage to improve our lease gathering margins by storing crude oil we have purchased for delivery in future months that are selling at a higher price. In a backwardated market, we use less storage capacity but increased lease gathering margins provide an offset to this reduced cash flow. We believe that the combination of our lease gathering activities and the commercial strategies used with our tankage provides a counter-cyclical balance that has a stabilizing effect on our operations and cash flow. In addition, we supplement the counter-cyclical balance of our asset base with derivative hedging activities in an effort to maintain a base level of margin irrespective of crude oil market conditions and, in certain circumstances, to realize incremental margin during volatile market conditions. References to counter-cyclical balance elsewhere in this report are referring to this relationship between our facilities activities and our supply and logistics activities in transitioning crude oil markets.

Table of Contents

Risk Management

As use of the financial markets for crude oil by producers, refiners, utilities and trading entities has increased, risk management strategies have become increasingly important in creating and maintaining margins. In order to hedge margins involving our physical assets and manage risks associated with our various commodity purchase and sale obligations (mainly relating to crude oil) and, in certain circumstances, to realize incremental margin during volatile market conditions, we use derivative instruments. These derivative instruments include exchange traded futures, options and swaps, as well as over-the-counter instruments. In analyzing our risk management activities, we draw a distinction between enterprise level risks and trading related risks. Enterprise level risks are those that underlie our core businesses and may be managed based on whether there is value in doing so. Conversely, trading related risks (the risks involved in trading in the hopes of generating an increased return) are not inherent in 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.

Our policy is generally to purchase only product for which we have a market, and to structure our sales contracts so that price fluctuations do not materially affect the segment profit we receive. We do not acquire and hold physical inventory, futures contracts or other derivative instruments for the purpose of speculating on outright commodity price changes as these activities could expose us to significant losses.

Although we seek to maintain a position that is substantially balanced within our supply and logistics activities, we purchase crude oil, refined products and LPG 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 Petroleum Company, LLC accounted for 14%, 14% and 19% of our revenues for each of the three years ended December 31, 2009, 2008 and 2007, respectively. Valero Marketing & Supply Company accounted for 10% of our revenues for the year ended December 31, 2007. ConocoPhillips Company accounted for 12%, 12% and 11% of our revenues for each of the three years ended December 31, 2009, 2008 and 2007, respectively. No other customers accounted for 10% or more of our revenues during any of the last three years. The majority of revenues from these customers pertain to our 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 incremental 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, investment banks that have established a trading platform, brokers and marketers of widely varying sizes, financial resources and

Table of Contents

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.

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

Following is a discussion of certain, 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.

Table of Contents

The HLPSA was amended by the Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. These amendments have resulted in the adoption of rules by the 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 $25 million in 2009, $23 million in 2008 and $15 million in 2007. Based on currently available information, our preliminary estimate for 2010 is that we will incur approximately $11 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 more recent 2002 and 2006 amendments.

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. 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.

We have expanded an internal review process in which we are reviewing 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. Environmental Protection Agency (EPA) enforcement actions, we may elect (as a result of our own internal initiatives) to spend substantial sums to ensure the integrity of and upgrade our pipeline systems and, in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines.

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

The DOT has 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 $22 million, $41 million and $18 million in 2009, 2008 and 2007, respectively. For 2010, we have budgeted approximately $28 million in connection with continued API 653 compliance activities and similar new EPA regulations for non-DOT tanks. 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 addition, market conditions may result in a significant demand for storage capacity. Accordingly, we may elect to spend more in 2010 than initially forecasted if economic conditions warrant.

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 $20 million in 2009, $8 million in 2008 and $6 million in 2007 on these types of costs. Our preliminary estimate for 2010 is approximately $21 million. Certain of these costs are recurring in nature and thus will affect future periods.

Table of Contents

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. We have knowledge of two Superfund sites where an affiliate (Scurlock Permian LLC) of a predecessor owner (Marathon Ashland Petroleum or

MAP) of assets we now own was alleged to have deposited waste oils, but MAP has contractually indemnified us for any liabilities associated with these two sites. 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.

Table of Contents

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 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, 2009, we had incurred approximately $16 million of remediation costs associated with these sites, while SOP s share has been approximately $6 million. In another example, as a result of our merger with Pacific, we assumed liability for a number of ongoing remediation sites associated with releases from pipeline or storage operations. We have evaluated each of the sites requiring remediation and developed reserve estimates for the Pacific sites, which total approximately $18 million. See Item 3. Legal Proceedings.

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

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 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 response to the Kyoto Protocol, the Canadian federal government introduced the *Regulatory Framework for Air Emissions* (the Regulatory Framework) for regulating air pollution and industrial GHG emissions by establishing mandatory emissions reduction requirements on a sector basis. Sector-specific regulations are expected to become effective in 2010.

Although the United States is not participating in the Kyoto Protocol, the U.S. Congress has been actively considering legislation to reduce emissions of GHGs. In addition, more than one-third of the states already have begun implementing legal measures to reduce emissions of GHGs, primarily through the development of GHG emission inventories and/or regional GHG cap and trade programs. Also, on December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In late September 2009, the EPA had proposed two sets of regulations in anticipation of finalizing its findings that would require a reduction in emissions of GHGs from motor vehicles that could also lead to the imposition of GHG emission limitations in Clean Air Act permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States beginning in 2011 for emissions occurring in 2010. Although the vast majority of our facilities were not subject to the EPA s GHG reporting rule adopted in September 2009. EPA has indicated that it is evaluating whether the rule should be applied to oil and gas production activities, perhaps on a field-wide basis.

Table of Contents

Operational components of our stationary facilities that require the combustion of carbon-based fuel (such as compression stations, line heaters and internal combustion engine-driven pumps) produce GHG emissions in the form of CO_2. Although we believe that these emissions in the aggregate are not significant relative to other industries that are fuel-combustion intensive, we have commenced a process of identifying potential emission sources and establishing GHG inventories for such sources.

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.

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 and Note 11 to our Consolidated Financial Statements. Federal, state and provincial regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with discharge permits or other requirements of the CWA.

The Oil Pollution Act of 1990 (OPA) amended certain provisions of the CWA, as they relate to the release of petroleum products into navigable waters. OPA subjects owners of facilities to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages, and certain other consequences of an oil spill. We believe that we are in substantial compliance with applicable OPA requirements. State and Canadian federal and provincial laws also impose requirements relating to the prevention of oil releases and the remediation of areas affected by releases when they occur. We believe that we are in substantial compliance with all such federal, state and Canadian requirements.

Other Regulation

Transportation Regulation

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

General Interstate Regulation. Our interstate common carrier 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 California Public Utility Commission, which prohibits certain of our subsidiaries from acting as guarantors of our senior notes and credit facilities. See Note 13 to our Consolidated Financial Statements.

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

Regulation of OCS Pipelines. The Outer Continental Shelf Lands Act requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. In June 2008, the Minerals Management Service 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.

Table of Contents

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 methodology for petroleum pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index (currently, the producer price index for finished goods plus 1.3 percent). Pipelines are allowed to raise their rates to the rate ceiling level generated by application of the index. If the methodology reduces the ceiling level such that it is lower than a pipeline s filed rate, the pipeline must reduce its rate to conform with the lower ceiling unless doing so would reduce a rate grandfathered by EPAct (see below) to below the grandfathered level. A pipeline must, as a general rule, use the indexing methodology to change its rates. The FERC, however, retained cost-of-service ratemaking, market-based rates, agreement with an unaffiliated shipper, and settlement as alternatives to the indexing approach that may be used in certain specified circumstances. The FERC s indexing methodology is subject to review every five years; the current methodology will remain in place through June 30, 2011. Because the indexing methodology 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.

FERC permits entities owning public utility assets, including oil pipelines, to include an income tax allowance in their cost-of-service rates to reflect the actual or potential income tax liability attributable to their public utility income, regardless of the form of ownership. A tax pass-through entity such as a master limited partnership (MLP) seeking such an income tax allowance would have to establish that its partners or members have an actual or potential income tax obligation on the entity s public utility income. Whether a pipeline s owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the FERC s current income tax allowance policy is generally favorable for pipelines that are organized as pass-through entities, such as MLPs, it still entails rate risk due to the case-by-case review requirement. FERC continues to refine its tax allowance policy in case-by-case reviews; how the tax allowance policy is applied in practice to pipelines owned by MLPs could affect the rates of pipelines regulated by FERC.

Our Pipelines. The FERC generally has not investigated rates on its own initiative when those rates have not been the subject of a protest or complaint by a shipper. Substantially all of our transportation segment profit 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.

Cross Border Regulation

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

Table of Contents

Natural Gas Storage Regulation

Interstate Regulation. The interstate storage facilities in which we have an investment are or will be subject to rate regulation by the FERC under the Natural Gas Act. The Natural Gas Act requires that tariff rates for gas storage facilities be just and reasonable and non-discriminatory. The FERC has authority to regulate rates and charges for natural gas transported and stored in U.S. interstate commerce or sold by a natural gas company via interstate commerce for resale. The FERC has granted our Pine Prairie and Bluewater gas storage facilies the authority to charge market-based rates.

The FERC also has authority over the construction and operation of U.S. transportation and storage facilities and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. In addition, FERC s authority extends to maintenance of accounts and records, terms and conditions of service, depreciation and amortization policies, acquisition and disposition of facilities, initiation and discontinuation of services, 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, 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 its 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. However, requests for rehearing are pending with the FERC. Accordingly, there may be further modifications to the Standards of Conduct upon rehearing.

Energy Policy Act of 2005. Pursuant to the EPAct 2005 and related regulations, it is unlawful in connection with the purchase or sale of natural gas or transportation services subject to the jurisdiction of the FERC to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the Natural Gas Act up to $1,000,000 per day per violation for violations occurring after August 8, 2005. The anti-manipulation rule and enhanced civil penalty authority reflect an expansion of the FERC s Natural Gas Act 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 1,500% since the end of 1998. At the same time that the scale and scope of our business activities have expanded, the breadth and depth of the available insurance markets have contracted. The overall cost of such insurance as well as the deductibles and overall retention levels that we maintain have increased. As a result, we

Table of Contents

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

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

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

Title to Properties and Rights-of-Way

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

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

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

Employees and Labor Relations

To carry out our operations, our general partner or its affiliates (including PMC (Nova Scotia) Company) employed approximately 3,400 employees at December 31, 2009. None of the employees of our general partner were subject to a collective bargaining agreement, except for eight employees covered by one agreement and another eight employees covered by another agreement. One of the collective bargaining agreements is scheduled for renegotiation in September 2012, while the other agreement is in effect until September 30, 2010. 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

Table of Contents

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

Partnership Allocations

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

Basis of Common Units

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

Limitations on Deductibility of Partnership Losses

In the case of taxpayers subject to the passive loss rules (generally, individuals and closely held corporations), any partnership losses 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

Table of Contents

addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, a unitholder may incur a tax liability in excess of the amount of cash the unitholder receives from the sale.

Foreign, State, Local and Other Tax Considerations

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

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

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

Available Information

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

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

Risks Related to Our Business

Table of Contents

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

We have a number of organic growth projects that require the expenditure of significant amounts of capital, including the Pier 400 project, the Pine Prairie gas storage facility and the Cushing, St. James and Patoka terminal and dock projects. Many of these projects involve numerous regulatory, environmental, commercial, weather-related, political and legal uncertainties that will be beyond our control. As these projects are undertaken, required approvals may not be obtained, may be delayed or may be obtained with conditions that materially alter the expected return associated with the underlying projects. Moreover, revenues associated with these organic growth projects will not increase immediately upon the expenditures of funds with respect to a particular project and these projects may be completed behind schedule or in excess of budgeted cost. 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 use the counter-cyclical aspects of our asset base or to capitalize on a volatile market.

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

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

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

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

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

Generally, it is our policy that we establish a margin for crude oil 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

Table of Contents

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 enhance our processes and procedures to detect future unauthorized trading. We cannot assure you, however, that these steps will detect and prevent all violations of our 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. Our asset base has more than tripled within the last five years. As we add assets, we historically have experienced a corresponding increase in the relative 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 aged and aging pipelines and terminals at acceptable levels.

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

Today we own more than two times the miles of pipeline we owned six years ago. 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 enhance 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. See Items 1 and 2. Business and Properties Regulation Environmental, Health and Safety Regulation Pipeline Safety/Pipeline and Storage Tank Integration Management.

The acquisitions we have completed over the last several years have included pipeline assets of varying ages and maintenance and operational histories. Accordingly, for 2010 and beyond we will continue to focus on pipeline integrity management as a primary operational emphasis. In that regard, we have added staff and implemented programs intended to improve the integrity of our assets, with a focus on risk reduction through testing, enhanced corrosion control, leak detection, and damage prevention. We have expanded an internal review process pursuant to which we review various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management mandate. The purpose of this process is to review the surrounding environment, condition and operating history of these pipeline and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, in addition to potential cost increases related to unanticipated regulatory changes or injunctive remedies resulting from EPA enforcement actions, we may elect (as

Table of Contents

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 or a significant event 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.

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.

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 on economically acceptable terms, our future growth may be limited.

Our ability to grow our distributions depends in part on our ability to make acquisitions that result in an increase in 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.

Table of Contents

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.

Table of Contents

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

Our sales of oil, natural gas, NGLs and other energy commodities, and related 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 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.

Table of Contents

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, 2009, our consolidated debt outstanding was approximately $5.2 billion, consisting of approximately $4.1 billion principal amount of long-term debt (including senior notes) and approximately $1.1 billion of short-term borrowings. As of December 31, 2009, we had approximately $950 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 Long-Term Debt.

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

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, bad weather, mechanical failures, grounding or collision, fire, explosion, environmental accidents, piracy, terrorism and political instability. Such occurrences could result in death or injury to persons, loss of property or environmental damage, delays in the delivery of cargo, loss of revenues from or termination of charter contracts, governmental fines, penalties or restrictions on conducting business, higher insurance rates and damage to our reputation and customer relationships generally. Although certain of these risks may be covered under our insurance program, any of these circumstances or events could increase our costs or lower our revenues.

Table of Contents

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, 2009, we had approximately $5.2 billion of consolidated debt, of which approximately $3.8 billion was at fixed interest rates and approximately $1.4 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. For example, the financial market turmoil, which started in 2007 and continued into 2009, impacted the exchange rate. The average monthly exchange rate for the Canadian dollar to U.S. dollar ranged between $1.05:1 and $1.26:1 during 2009.

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, 2009, we had $1.3 billion of goodwill, of which approximately $875 million was recorded upon completion of our merger with Pacific. The purchase price for the Pacific merger was approximately $2.5 billion. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the acquired tangible and separately measurable intangible net assets. U.S. generally accepted accounting principles, or GAAP, requires us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. If we were to determine that any of our 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.

Table of Contents

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 at Bluewater and Pine Prairie 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.

Table of Contents

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 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.

Table of Contents

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

Risks Related to an Investment in Our Debt Securities

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

Our debt securities are effectively subordinated to claims of our secured creditors and the guarantees are effectively subordinated to the claims of our secured creditors as well as the secured creditors of our subsidiary guarantors. Although 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.

Table of Contents

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, 2009, our total outstanding debt was approximately $5.2 billion. We will be prohibited from making cash distributions during an event of default under any of our indebtedness. Various limitations in our credit facilities may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

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

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.

Table of Contents

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 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.

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.

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. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service, or the IRS, on this or any other tax matter affecting us.

Despite the fact that we are classified as a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe, based upon our current operations, that we will be so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

Table of Contents

Current law may change causing us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Specifically, beginning in 2008, we 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. 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.

Certain of our Canadian subsidiaries are corporations for Canadian tax purposes, thus their operations are subject to Canadian federal and provincial income taxes. The remainder of our Canadian operations is conducted through an operating limited partnership, which has historically been treated as a flow-through entity for tax purposes. This entity is subject to Canadian legislation passed in June 2007 that imposes entity-level taxes on certain types of flow-through entities. This legislation refers to safe harbor guidelines that grandfather certain existing entities (which, we believe, would include us) and delay the effective date of such legislation until 2011 provided that the entities do not exceed the normal growth guidelines. Although we continuously review acquisition opportunities that, if consummated, could cause us to exceed the normal growth guidelines, we believe that we are currently within the normal growth guidelines. Additionally, in December 2008, the Fifth Protocol to the U.S./Canada Tax Treaty was ratified and contained language that increases the withholding tax on dividends and intercompany interest effective in 2010. As a result of these collective changes, we are evaluating a number of alternatives to restructure our Canadian subsidiaries to optimize both entity and equity owner level taxes. We anticipate effecting any structural changes in 2010 or early 2011.

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

We will be considered to have been terminated for tax purposes if there are sales or exchanges which, in the aggregate, constitute 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of measuring whether the 50% threshold is reached, multiple sales of the same interest are counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in 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.

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 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.

Table of Contents

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

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

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

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

Because we cannot match transferors and transferees 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 foreign taxes and return filing requirements in states and jurisdictions where they do not live as a result of investing in our units.

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

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

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

Table of Contents

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

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

Our method of proration of items of income, gain, loss and deduction between transferors and transferees may not be permitted under existing Treasury Regulations. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

None.

Item 3. ***Legal Proceedings***

Pipeline Releases. In January 2005 and December 2004, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In late December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains, the U.S. Environmental Protection Agency (the EPA), the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 980 and 4,200 barrels were recovered from the two respective sites. The unrecovered oil was removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $5 million to $6 million. In cooperation with the appropriate state and federal environmental authorities, we have completed our work with

Table of Contents

respect to site restoration, subject to some ongoing remediation at the Pecos River site. EPA has referred these two crude oil releases, as well as several other smaller releases, to the U.S. Department of Justice (the DOJ) for further investigation in connection with a civil penalty enforcement action under the Federal Clean Water Act. We have cooperated in the investigation and are currently involved in settlement discussions with DOJ and EPA. Our assessment is that it is probable we will pay penalties related to the releases. We may also be subjected to injunctive remedies that would impose additional requirements, costs and constraints on our operations. We have accrued our current estimate of the likely penalties as a loss contingency, which is included in the estimated aggregate costs set forth above. We understand that the maximum permissible penalty, if any, that EPA could assess with respect to the subject releases under relevant statutes would be approximately $6.8 million. Such statutes contemplate the potential for substantial reduction in penalties based on mitigating circumstances and factors. We believe that several of such circumstances and factors exist, and thus have been a primary focus in our discussions with the DOJ and EPA with respect to these matters.

SemCrude L.P., et al Debtors (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. As a result of our statutory protections and contractual rights of setoff, substantially all of our pre-petition claims against SemCrude should be satisfied. Certain creditors of SemCrude and its affiliates have challenged our contractual and statutory rights to set off certain of our payables to the debtor against our receivables from the debtor. The aggregate amount subject to challenge is approximately $23 million. Certain SemCrude creditors have also filed state court actions alleging a producer s lien on crude oil sold to SemCrude, and the continuation of such lien when SemCrude sold the oil to subsequent purchasers such as us. These suits may be consolidated and heard in the U.S. Bankruptcy Court in Delaware. We intend to vigorously defend our contractual and statutory rights.

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

United States of America v. Pacific Pipeline System, LLC (PPS). In March 2005, a release of approximately 3,400 barrels of crude oil occurred on Line 63, subsequently acquired by us in the Pacific merger. The release occurred when the pipeline was severed as a result of a landslide caused by heavy rainfall in the Pyramid Lake area of Los Angeles County. Total projected emergency response, remediation and restoration costs are approximately $26 million, substantially all of which have been incurred and recovered under a pre-existing PPS pollution liability insurance policy. In September 2008, the EPA filed a civil complaint against PPS, a subsidiary acquired in the Pacific merger, in connection with the Pyramid Lake release. The complaint, which was filed in the Federal District Court for the Central District of California, Civil Action No. CV08-5768DSF(SSX), seeks the maximum permissible penalty under the relevant statutes of approximately $3.7 million. In January 2010, the DOJ, EPA and PPS entered into a proposed consent decree, which will be published in the Federal Register and then be subject to a 30-day public comment period. If there are no objections prior to the end of the public comment period, the Court is expected to sign the consent decree. After the consent decree becomes effective, PPS will pay a civil penalty of $1.3 million and comply with other requirements set forth in the consent decree, which include performance of additional remediation and restoration tasks. Total projected costs associated with this additional work are estimated at less than $6 million. PPS is also prohibited from transferring ownership of Line 63 to an unaffiliated entity unless the transferee agrees in writing to be bound by any provisions of the consent decree that have not been previously satisfied. This prohibition on transfer will not apply if PPS retains a portion of ownership and continues as operator of the line.

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 the Pacific Atlantic Terminals LLC (PAT) facility at Paulsboro, New Jersey. We estimate that the maximum potential cost to effectively remediate ranges up to $10 million although the New Jersey Department of Environmental Protection (NJDEP) is asserting a much larger expenditure. Both ExxonMobil and GATX were prior owners of the terminal. We contend that ExxonMobil and 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 PAT is directly or indirectly liable for damages or costs associated with the contamination.

New Jersey Dep t 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 and ExxonMobil to recover natural resources damages associated with, and to require remediation of, the contamination. ExxonMobil and GATX have filed third-party demands against PAT, seeking indemnity and contribution. NJDEP environmental consultants have asserted a significant clean-up expense as indicated. Discussions with the NJDEP have commenced.

EPA v. Rocky Mountain Pipeline System. In February 2009, we received a request for information from EPA regarding

Table of Contents

aspects of the fuel handling activities of Rocky Mountain Pipeline System (RMPS), a subsidiary acquired in the Pacific merger, at two truck terminals in Colorado. These activities, performed at the request of customers, 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 (CAA) 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. We plan to engage in discussion with EPA, and to emphasize factors intended to 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 been filed.

Other Pacific-Legacy Matters. At the time of its merger with Plains, Pacific had completed a number of acquisitions that had not been fully integrated into its operations. Accordingly, we have and may become aware of various instances in which some of these operations may not have been fully compliant with applicable environmental and safety regulations. Although we have been working to bring all of these operations into compliance with applicable requirements, any past noncompliance could result in the imposition of fines, penalties or corrective action requirements by governmental entities. Although we believe that our operations are presently in material compliance with applicable requirements, 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 that may have occurred.

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

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

At December 31, 2009, our reserve for environmental liabilities totaled approximately $62 million, of which approximately $10 million is classified as short-term and $52 million is classified as long-term. At December 31, 2009, we have recorded receivables totaling approximately $3 million for amounts that are probable of recovery under insurance and from third parties under indemnification agreements.

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

Other. A pipeline, terminal or other facility may experience damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers our assets in amounts considered reasonable.

Table of Contents

The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. Our environmental insurance coverage is generally structured to cover sudden environmental events but not gradual activities which may continue unnoticed for a material period of time. The overall trend in the environmental insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased.

Absent a material favorable change in the environmental insurance markets, this trend is expected to continue as we continue to grow and expand. As a result, we anticipate that we will elect to self-insure more of our environmental and wind damage exposures, incorporate higher retention in our insurance arrangements, pay higher premiums or some combinations of such actions.

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

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

None.

Table of Contents

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, 2010, the closing market price for our common units was $54.90 per unit and there were approximately 120,000 record holders and beneficial owners (held in street name). As of February 22, 2010, there were 136,135,988 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)
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
2008					
4th Quarter	$	42.39	$	23.25	$ 0.8925
3rd Quarter	$	48.36	$	35.68	$ 0.8925
2nd Quarter	$	50.96	$	44.54	$ 0.8875
1st Quarter	$	52.44	$	43.93	$ 0.8650

(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 and Rainbow Pipeline Company (Rainbow) in May 2008, our general partner agreed to reduce the amounts due to it as incentive distributions. Additionally, in connection with the PNGS acquisition in September 2009, our general partner agreed to further reduce its incentive distributions by an aggregate of $8 million over the next two years $1.25 million per quarter for the first four

Table of Contents

quarters and $0.75 million per quarter for the next four quarters. This incentive distribution reduction became effective upon payment of our November 2009 quarterly distribution of $0.9200 per limited partner unit. The total reduction in incentive distributions related to the Pacific, Rainbow and PNGS acquisitions is $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 2010 (as discussed below), the aggregate remaining incentive distribution reductions will be approximately $18 million.

We paid $127 million to the general partner in incentive distributions in 2009. Additionally, on February 12, 2010, we paid a quarterly distribution of $0.9275 per unit applicable to the fourth quarter of 2009, of which approximately $40 million was paid to the general partner. See Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner.

Under the terms of the agreements governing our debt, we are prohibited from declaring or paying any distribution to unitholders if a default or event of default (as defined in such agreements) exists. 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 Long-Term Debt.

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 fiscal 2009, and we do not have any announced or existing plans to repurchase any of our common units.

Item 6. *Selected Financial Data*

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2009, 2008, 2007, 2006 and 2005 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.

Table of Contents

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(in millions, except for per unit data)				
Statement of operations data:					
Total revenues (1)	$ 18,520	$ 30,061	$ 20,394	$ 22,445	$ 31,177
Income before cumulative effect of change in accounting principle (2)	$ 580	$ 437	$ 365	$ 279	$ 218
Net income	$ 580	$ 437	$ 365	$ 285	$ 218
Net income attributable to Plains	$ 579	$ 437	$ 365	$ 285	$ 218
Per unit data:					
Basic net income before cumulative effect of change in accounting principle (2)	$ 3.34	$ 2.66	$ 2.47	$ 2.85	$ 2.83
Basic net income after cumulative effect of change in accounting principle	$ 3.34	$ 2.66	$ 2.47	$ 2.93	$ 2.83
Diluted net income before cumulative effect of change in accounting principle (2)	$ 3.32	$ 2.64	$ 2.45	$ 2.82	$ 2.78
Diluted net income after cumulative effect of change in accounting principle	$ 3.32	$ 2.64	$ 2.45	$ 2.90	$ 2.78
Declared distributions per limited partner unit (3)	$ 3.62	$ 3.50	$ 3.28	$ 2.87	$ 2.58
Balance sheet data (at end of period):					
Total assets	$ 12,358	$ 10,032	$ 9,906	$ 8,715	$ 4,120
Long-term debt	$ 4,142	$ 3,259	$ 2,624	$ 2,626	$ 952
Total debt	$ 5,216	$ 4,286	$ 3,584	$ 3,627	$ 1,330
Partners' capital	$ 4,159	$ 3,552	$ 3,424	$ 2,977	$ 1,331
Other data:					
Net cash provided by (used in) operating activities	$ 365	$ 857	$ 796	$ (276)	$ 24
Net cash used in investing activities	$ (660)	$ (1,339)	$ (663)	$ (1,651)	$ (297)
Net cash provided by (used in) financing activities	$ 312	$ 464	$ (124)	$ 1,927	$ 271
Capital expenditures:					
Acquisitions	$ 393	$ 735	$ 125	$ 3,021	$ 40
Internal growth projects	$ 364	$ 491	$ 525	$ 332	$ 149
Maintenance	$ 81	$ 81	$ 50	$ 28	$ 14
Investments in unconsolidated subsidiaries	$ 15	$ 37	$ 9	$ 44	$ 113

Table of Contents

	Year Ended December 31,				
	2009	2008	2007	2006	2005
Volumes (4) (5) (6)					
Transportation segment (average daily volumes in thousands of barrels):					
Tariff activities	2,836	2,851	2,712	2,106	1,799
Trucking	85	97	105	101	84
Transportation segment total	2,921	2,948	2,817	2,207	1,883
Facilities segment:					
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	56	53	46	25	22
Natural gas storage (average monthly capacity in billion cubic feet (Bcf))	26	14	13	13	4
LPG processing (average daily throughput in thousands of barrels)	15	17	18	12	
Facilities segment total (average monthly capacity in millions of barrels)	61	56	48	27	22
Supply & Logistics segment (average daily volumes in thousands of barrels):					
Crude oil lease gathering purchases	612	658	685	650	610
Refined products sales	35	26	11	N/A	N/A
LPG sales	105	103	90	70	56
Waterborne foreign crude imported	55	80	71	63	59
Supply & Logistics segment total	807	867	857	783	725

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

(2) Income from continuing operations before cumulative effect of change in accounting principle pro forma for the impact of the January 1, 2006 change in our method of accounting for unit-based payment transactions would have been $224 million for 2005. In addition, basic net income per limited partner unit before cumulative effect of change in accounting principle would have been $2.81 ($2.76 diluted) for 2005.

(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. Therefore, natural gas storage volumes for September 2005 through August 2009 are netted to our 50% interest in PNGS. September through December 2009 volumes represent our 100% interest in PNGS. See Note 3 to our Consolidated Financial Statements for additional discussion regarding the PNGS acquisition.

Table of Contents

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

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

Introduction

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

Our discussion and analysis includes the following:

- Executive Summary
- Company Overview
- Overview of Operating Results, Capital 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, supply and logistics services with respect to crude oil, refined products and LPG. We are also engaged 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. We previously referred to the Supply and Logistics segment as the Marketing segment. We revised the segment name to better describe the business activities conducted within that segment.

See Results of Operations Analysis of Operating Segments for further discussion.

Overview of Operating Results, Capital Spending and Significant Activities

During 2009, our operations provided favorable growth over 2008 and 2007 levels. All three of our segments provided favorable operating results, particularly our supply and logistics segment. The supply and logistics segment benefited from the favorable steep contango crude oil market structure early in the period. Our LPG margins also benefited from strong demand for propane. Our transportation and facilities operating results benefited from expansions in our asset base through acquisitions and our ongoing internal growth projects. Additional key items impacting 2009 include:

Table of Contents

- The issuance of 5,750,000 common units at $36.90 per unit for net proceeds of approximately $210 million in March 2009, and the issuance of 5,290,000 common units at $46.70 per unit for net proceeds of approximately $246 million in September 2009.

- The issuance and repayment of the following senior notes:

- Issuance of $350 million of 8.75% senior notes for net proceeds of approximately $347 million in April 2009.

- Issuance of $500 million of 4.25% senior notes for net proceeds of approximately $497 million in July 2009.

- Repayment of $175 million of 4.75% senior notes in August 2009.

- Issuance of $500 million of 5.75% senior notes for net proceeds of approximately $494 million in September 2009.

- Repayment of $250 million of 7.13% senior notes in October 2009. We also recognized a loss of approximately $4 million in conjunction with the early redemption of these notes.

Acquisitions and Internal Growth Projects

We completed a number of acquisitions and capital expansion projects in 2009, 2008 and 2007 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,		
	2009	**2008**	**2007**
Acquisition capital	$ 393	$ 735	$ 125
Internal growth projects	364	491	525
Maintenance capital	81	81	50
Investment in unconsolidated entities	15	37	9
	$ 853	$ 1,344	$ 709

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 2009, 2008 and 2007 is set forth in the table below (in millions):

Table of Contents

Acquisition	Effective Date		Acquisition Price	Operating Segment
PNGS	09/03/2009	$	215	Facilities
Other (1)	Various		178	Transportation & Facilities
2009 Total		$	393	
Rainbow	05/01/2008	$	687	Transportation
San Pedro and other	11/13/2008		48	Facilities
2008 Total		$	735	
Bumstead LPG Storage Facility	07/24/2007	$	52	Facilities
Tirzah LPG Storage Facility	10/2/2007		54	Facilities
Other	Various		19	Transportation and Supply & Logistics
2007 Total		$	125	

(1) Consists of six small acquisitions.

Internal Growth Projects

Our 2009 projects included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2009, 2008 and 2007 projects (in millions):

Projects		2009		2008		2007
St. James - Phase III (1)	$	71	$	27	$	14
Nipisi storage and truck terminal (1)		35				
Kerrobert pumping project		34		9		
Rangeland tankage		31		12		
Cushing - Phase VII (1)		25				
Patoka tankage - Phase I		6		55		30
Patoka tankage - Phase II (1)		14		1		
Paulsboro tankage		11		30		2
Salt Lake City expansion		8		154		73
Fort Laramie tank expansion		2		20		12
St. James, Louisiana storage facility		2		17		68
Other projects (2)		125		166		326
Total	$	364	$	491	$	525

(1) These projects will continue into 2010. See Liquidity and Capital Resources Capital Expenditures and Distributions Paid to Our Unitholders and General Partner 2010 Capital Expansion Projects.

(2) Primarily consists of gas storage construction projects, pipeline connections, upgrades and truck stations, and new tank construction and refurbishing.

Table of Contents

Critical Accounting Policies and Estimates

Critical Accounting Policies

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

Critical Accounting Estimates

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

Purchase and Sales Accruals. We routinely make accruals based on estimates for certain components of our revenues and cost of sales due to the timing of compiling billing information, receiving third party information and reconciling our records with those of third parties. Where applicable, these accruals are based on nominated volumes expected to be purchased, transported and subsequently sold. Uncertainties involved in these estimates include levels of production at the wellhead, access to certain qualities of crude oil, pipeline capacities and delivery times, utilization of truck fleets to transport volumes to their destinations, weather, market conditions and other forces beyond our control. These estimates are generally associated with a portion of the last month of each reporting period. For the year ended December 31, 2009, we estimate that approximately 3%, 3%, 8% and 11% of annual revenues, cost of sales, operating income and net income attributable to Plains, respectively, were recorded using purchase and sales estimates. Accordingly, a 10% variance from this estimate would impact the respective 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 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 recognized. Any subsequent adjustments to this estimate, if material, will be recognized retroactive to the date of acquisition. 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 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, 2009, 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, 2009 (as performed during the prior year due to economic conditions). 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 2009, 2008 or 2007. See Note 2 to our Consolidated Financial Statements for a further discussion of goodwill.

Mark-to-Market Accrual. In situations where we are required to mark-to-market derivatives, the estimates of gains or losses at a particular period end do not reflect the end results of particular transactions, and will most likely not reflect the actual gain or loss at the conclusion of a transaction. We reflect estimates for these items based on our internal records and information from third parties. 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, insurance claims, asset retirement obligations, taxes and potential legal claims. Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Our estimates are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our environmental remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment, costs of medical care associated with worker s compensation and employee health insurance claims, and the possibility of existing legal claims giving rise to additional claims. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. A variance of 5% in our aggregate estimate for the accruals and contingent liabilities discussed above would have an impact on earnings of up to approximately $13 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 awards granted under our various Long Term Incentive Plans as well as outstanding Class B units of Plains AAP, L.P. (collectively, our equity compensation plans). Under generally accepted accounting principles, we are required to estimate the fair value of our outstanding equity awards and recognize that fair value as compensation expense over the service period. For equity awards that contain a performance condition, the fair value of the equity award is recognized as compensation expense only if the attainment of the performance condition is considered probable.

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

For the Class B units of Plains AAP, L.P., the total compensation expense recognized over the service period is equal to the grant date fair value of the Class B units that become earned. The Class B units become earned in various increments upon us achieving annualized distribution levels of $3.50, $3.75, $4.00 and $4.50. When earned, the Class B units will be entitled to participate in distributions paid by Plains AAP, L.P. in excess of $11 million (as adjusted for debt service costs and excluding special distributions funded by debt) per quarter. Uncertainties involved in this estimate include the estimated date that we will achieve the annualized distribution levels required and the continued employment of personnel who have been awarded Class B units.

We recognized total compensation expense of approximately $68 million, $24 million and $49 million in 2009, 2008 and 2007, 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.

Table of Contents

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

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

During 2009, we recognized impairments of less than $1 million for assets taken out of service. Impairments of approximately $5 million and $1 million were recognized during 2008 and 2007, respectively.

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

Recent Accounting Pronouncements

See Note 2 to our Consolidated Financial Statements for a discussion of recent accounting pronouncements that will impact us.

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 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.

Table of Contents

	For the Twelve Months Ended December 31,			Favorable (Unfavorable)			
				2009-2008		2008-2007	
	2009	2008	2007	$	%	$	%
	(In millions, except per unit data)						
Transportation segment profit	$ 477	$ 445	$ 334	$ 32	7%	$ 111	33%
Facilities segment profit	208	153	110	55	36%	43	39%
Supply & Logistics segment profit	345	221	269	124	56%	(48)	(18)%
Total segment profit	1,030	819	713	211	26%	106	15%
Depreciation and amortization	(236)	(211)	(180)	(25)	(12)%	(31)	(17)%
Interest expense	(224)	(196)	(162)	(28)	(14)%	(34)	(21)%
Other income, net	16	33	10	(17)	(52)%	23	230%
Income tax expense	(6)	(8)	(16)	2	25%	8	50%
Net income	580	437	365	143	33%	72	20%
Less: Net income attributable to noncontrolling interest	(1)			(1)	N/A		
Net income attributable to Plains	$ 579	$ 437	$ 365	$ 142	32%	$ 72	20%
Earnings per basic limited partner unit	$ 3.34	$ 2.66	$ 2.47	$ 0.68	26%	$ 0.19	8%
Earnings per diluted limited partner unit	$ 3.32	$ 2.64	$ 2.45	$ 0.68	26%	$ 0.19	8%
Basic weighted average units outstanding	130	120	113	10	8%	7	6%
Diluted weighted average units outstanding	131	121	114	10	8%	7	6%

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:

				Favorable (Unfavorable)			
Operating Results (1)	Year Ended December 31,			2009-2008		2008-2007	
(in millions, except per barrel amounts)	2009	2008	2007	$	%	$	%
Revenues (1)							
Tariff activities	$ 867	$ 800	$ 654	$ 67	8%	$ 146	22%
Trucking	94	127	117	(33)	(26)%	10	9%
Total transportation revenues	961	927	771	34	4%	156	20%
Cost and Expenses (1)							
Trucking costs	(63)	(88)	(80)	25	28%	(8)	(10)%
Field operating costs (excluding equity compensation expense)	(333)	(331)	(288)	(2)	(1)%	(43)	(15)%
Equity compensation expense - operations (2)	(9)	(1)	(5)	(8)	(800)%	4	80%
Segment G&A expenses (excluding equity compensation expense)	(61)	(56)	(50)	(5)	(9)%	(6)	(12)%
Equity compensation expense - general and administrative (2)	(25)	(11)	(19)	(14)	(127)%	8	42%
Equity earnings in unconsolidated entities	7	5	5	2	40%		

Segment profit	$	477	$	445	$	334	$	32	7%	$	111	33%
Maintenance capital	$	57	$	54	$	34	$	3	6%	$	20	59%
Segment profit per barrel	$	0.45	$	0.41	$	0.34	$	0.04	10%	$	0.07	21%

Table of Contents

Average Daily Volumes	**Year Ended December 31,**			**Favorable (Unfavorable) 2009-2008**		**2008-2007**	
(in thousands of barrels per day) (3)	**2009**	**2008**	**2007**	**Volumes**	**%**	**Volumes**	**%**
Tariff activities							
All American	40	45	47	(5)	(11)%	(2)	(4)%
Basin	394	377	378	17	5%	(1)	
Capline	193	219	235	(26)	(12)%	(16)	(7)%
Line 63/Line 2000	131	147	175	(16)	(11)%	(28)	(16)%
Salt Lake City Area Systems	131	93	101	38	41%	(8)	(8)%
West Texas/New Mexico Area Systems	368	372	369	(4)	(1)%	3	1%
Manito	63	70	73	(7)	(10)%	(3)	(4)%
Rainbow	183	129		54	42%	129	N/A
Rangeland	53	58	63	(5)	(9)%	(5)	(8)%
Refined products	100	109	109	(9)	(8)%		
Other	1,180	1,232	1,162	(52)	(4)%	70	6%
Tariff activities total	2,836	2,851	2,712	(15)	(1)%	139	5%
Trucking	85	97	105	(12)	(12)%	(8)	(8)%
Transporation segment total	2,921	2,948	2,817	(27)	(1)%	131	5%

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

(2) Equity compensation expense related to 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 transportation segment revenues increased in each year and our volumes remained relatively consistent for 2009 compared to 2008 and increased approximately 5% for 2008 compared to 2007. Volumes were positively impacted by (i) the Rainbow acquisition completed in May 2008, which added approximately 129,000 barrels per day to average 2008 volumes and approximately 183,000 barrels per day to average 2009 volumes and (ii) the completion in the fourth quarter of 2008 of a 94-mile expansion of our Salt Lake Area system. The increases from these acquisition and expansion activities were generally offset in 2009 and partially offset in 2008 by volume fluctuations on various other pipeline segments as well as decreased trucking volumes over the three year period. The decreased trucking volumes were primarily due to decreased demand as well as an effort to eliminate lower margin activities.

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

- The Rainbow acquisition contributed approximately $16 million and $50 million of incremental revenue to 2009 and 2008, respectively.

- 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.

- Loss allowance revenues increased by approximately $22 million for 2009 compared to 2008 primarily related to a higher average realized price per barrel during 2009 (including the impact of gains from derivative activities). Loss allowance revenues increased by approximately $31 million for 2008 compared to 2007 due to slightly higher volumes and an increase in the average realized price per barrel during most of 2008 relative to 2007.

Table of Contents

- Tariff rates increased on certain of our pipeline systems after the second quarter of each year as a result of indexing by the Federal Energy Regulation Commission (FERC). In addition, we had similar type rate increases on non-FERC regulated pipelines.

- Revenues for the year ended December 31, 2008 were impacted by a gain of approximately $17 million related to a linefill hedge entered into in conjunction with the Rainbow acquisition.

- Trucking revenues decreased for 2009 compared to 2008 by approximately $33 million, primarily related to the volume decrease discussed within our operating revenues and volumes lead in. Trucking revenues increased for 2008 compared to 2007 by approximately $10 million due to the acquisition of trucking businesses in prior years.

- Revenues and expenses from our Canadian based subsidiaries, which use the Canadian dollar as their functional currency, are translated at average exchange rates prevailing for each month. During 2009, revenues from some of our Canadian pipeline systems were unfavorably impacted by the appreciation of the U.S. dollar relative to the Canadian dollar. The average Canadian dollar (CAD) to U.S. dollar (USD) exchange rate for 2009 was $1.14 CAD: $1.00 USD compared to an average of $1.07 CAD: $1.00 USD in 2008 and in 2007.

- Miscellaneous revenue and volume variances on various other systems, including the impacts of Hurricanes Gustav and Ike, both of which affected the Gulf Coast area during the third quarter of 2008.

Costs and Expenses. In general, our overall transportation costs and expenses have trended up primarily due to our continued growth through acquisitions and expansion activities. However, overall costs were favorably impacted in 2009 by the appreciation of the U.S. dollar relative to the Canadian dollar. Various factors impacting components of our cost structure include:

Trucking Costs. Trucking costs decreased in 2009 as compared to 2008 primarily as a result of decreased trucking volumes, as discussed above, and as a result of lower rates resulting from lower fuel costs. Trucking cost increased in 2008 as compared to 2007 primarily as a result of increased rates resulting from higher fuel costs. This increase was partially offset by lower costs resulting from lower trucking volumes.

Field Operating Costs. Field operating costs (excluding equity compensation charges as discussed below) increased $2 million in 2009 over 2008 and $43 million in 2008 over 2007. The primary driver of this increase was the Rainbow acquisition that was completed in May 2008, which added $17 million for the year ended December 31, 2008, and an additional $2 million for the year ended December 31, 2009. In addition, during the year ended December 31, 2009 we had increased payroll, benefit and maintenance costs that were offset by lower API 653, in-line inspection, utility and fuel costs. Costs related to API 653 and in-line inspections had increased in 2008 in an effort to meet the 2009 compliance deadline. In addition, utility and fuel costs had increased in 2008 as a result of higher rates, and decreased again in 2009 as fuel and power rates decreased. Our overall operating expenses also increased during 2008 as compared to 2007 due to general inflationary pressures experienced in the industry and from our expanded asset base including assets from the Pacific merger in late 2006.

General and Administrative Expenses. General and administrative expenses (excluding equity compensation charges as discussed below) have increased in 2009 compared to 2008 and in 2008 compared to 2007 related to our acquisitions and expansion activities as well as upward cost pressures from payroll and benefits and other personnel related costs.

Equity Compensation Charges. Equity compensation charges increased approximately $22 million in 2009 compared to 2008 and decreased by $12 million in 2008 as compared to 2007. Such variations are primarily the result of an increase in unit price for 2009 relative to 2008 and a decrease in unit price in 2008 relative to 2007. 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 and $52.00 per unit at the end of 2007. The impact of these price fluctuations are partially impacted by additional equity compensation grants during each period (including the Class B grants), changes to our probability assessment that result in accruals for grants that were previously not considered to be probable of vesting and forfeitures. See Note 10 to our Consolidated Financial Statements for additional information on our equity compensation plans.

Maintenance Capital. The increase in maintenance capital in 2008 compared to 2007 is primarily due to increased investment applicable to in-line inspections and API 653 repairs in an effort to meet our May 2009 compliance deadline, general inflationary pressures experienced in the industry, our expanded asset base including assets from the Pacific merger in late 2006, and the Rainbow acquisition.

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

Table of Contents

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, 2009**	**2008**	**2007**	**Favorable (Unfavorable) 2009-2008 $**	**%**	**2008-2007 $**	**%**
Storage and terminalling revenues **(1)**	$ 362	$ 270	$ 210	$ 92	34%	$ 60	29%
Storage related costs	(5)			(5)	N/A		
Field operating costs (excluding equity compensation charge)	(120)	(104)	(84)	(16)	(15)%	(20)	(24)%
Equity compensation charge - operations **(2)**	(1)			(1)	N/A		
Segment G&A expenses (excluding equity compensation expense)	(26)	(18)	(18)	(8)	(44)%		
Equity compensation expense - general and administrative **(2)**	(10)	(4)	(8)	(6)	(150)%	4	50%
Equity earnings in unconsolidated entities	8	9	10	(1)	(11)%	(1)	(10)%
Segment profit	$ 208	$ 153	$ 110	$ 55	36%	$ 43	39%
Maintenance capital	$ 16	$ 23	$ 10	$ (7)	(30)%	$ 13	130%
Segment profit per barrel	$ 0.29	$ 0.23	$ 0.19	$ 0.06	26%	$ 0.04	21%

Volumes (3) (4) (5)	**For the Year Ended December 31, 2009**	**2008**	**2007**	**Favorable (Unfavorable) 2009-2008 Volumes**	**%**	**2008-2007 Volumes**	**%**
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	56	53	46	3	6%	7	15%
Natural gas storage (average monthly capacity in bcf)	26	14	13	12	86%	1	8%
LPG processing (average throughput in thousands of barrels per day)	15	17	18	(2)	(12)%	(1)	(6)%
Facilities segment total (average monthly capacity in millions of barrels)	61	56	48	5	9%	8	17%

(1) Revenues include intersegment amounts.

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

(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 2008 and January through August 2009 are netted to our 50% interest in PNGS. September through December 2009 volumes represent our 100% interest in PNGS.

(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 oil barrel ratio; and (iii) LPG processing volumes multiplied by the number of days in the year and divided by the number of months in the year.

Table of Contents

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

Operating Revenues and Volumes. As noted in the table above, our facilities segment revenues and volumes increased for 2009 compared to 2008 and for 2008 compared to 2007. The significant variances in volumes and revenues between 2009, 2008 and 2007 are discussed below:

- Acquisitions Revenues and volumes for 2009 compared to 2008 were impacted by the PNGS acquisition, which closed during the third quarter of 2009 and the acquisition of a natural gas processing business, which closed during the second quarter of 2009. 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.

Revenues and volumes for 2008 compared to 2007 were impacted by the Bumstead and Tirzah acquisitions in 2007 in addition to the San Pedro acquisition that we closed during the fourth quarter of 2008. The Bumstead acquisition was completed in the third quarter of 2007 and the Tirzah acquisition was completed in the fourth quarter of 2007. Such acquisitions contributed approximately $13 million in additional revenue for the year ended December 31, 2008.

- Expansion Projects Expansion projects also resulted in an increase in revenues and volumes in 2009 compared to 2008, which included expansion projects at the Paulsboro, Patoka, St. James and Ft. Laramie facilities. Revenues for these facilities increased by a combined $31 million for 2009. Aggregate volumes increased by approximately 5 million barrels for 2009 at these facilities.

Expansion projects also resulted in an increase in revenues and volumes in 2008 compared to 2007, which included expansion projects at the Cushing, Martinez and St. James facilities. Revenues for these facilities increased by a combined $37 million for 2008. Aggregate volumes increased by approximately 6 million barrels for 2008 at these facilities.

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

Field Operating Costs. Field operating costs (excluding equity compensation charges as discussed below) increased in most categories during the years ended December 31, 2009 and 2008 primarily due to our continued growth through (i) additional tankage placed into service over the last few years at various terminals, including Cushing, Martinez, Paulsboro and St. James and (ii) acquisitions such as the PNGS and natural gas processing acquisitions completed in 2009 and the Tirzah and Bumstead acquisitions completed during 2007.

General and Administrative Expenses. Our general and administrative expenses (excluding equity compensation charges as discussed below) increased during the year ended December 31, 2009 primarily due to our continued growth through acquisitions, such as the PNGS and natural gas processing acquisitions completed in 2009.

Equity Compensation Charges. Equity compensation charges increased approximately $7 million in 2009 compared to 2008 and decreased approximately $4 million in 2008 as compared to 2007. Such variations are primarily as a result of an increase in unit price for 2009 relative to 2008 and a decrease in unit price in 2008 relative to 2007. 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 and $52.00 per unit at the end of 2007. The impact of these price fluctuations are partially impacted by additional equity compensation grants during each period (including the Class B grants), changes to our probability assessment that result in accruals for grants that were previously not considered to be probable of vesting and forfeitures. See Note 10 to our Consolidated Financial Statements for additional information on our equity compensation plans.

Maintenance Capital. The decrease in maintenance capital for the year ended December 31, 2009 compared to the year ended December 31, 2008 is primarily due to a decrease in API 653 repairs required to meet our May 2009 compliance deadline. The increase in maintenance capital for 2008 compared to 2007 was primarily due to maintenance capital incurred at various terminals, including the Martinez, Richmond, LA Basin and Cushing terminals to meet the 2009 deadline for API 653, general inflationary pressures experienced in the industry, and our expanded asset base including assets from the Pacific merger in late 2006.

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.

Table of Contents

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) refined products volumes, (iii) LPG sales volumes and (iv) 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 counter-cyclical 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, 2009**	**2008**	**2007**	**Favorable (Unfavorable) 2009-2008 $**	**%**	**2008-2007 $**	**%**
Revenues	$ 17,759	$ 29,350	$ 19,858	$ (11,591)	(39)%	$ 9,492	48%
Purchases and related costs (2)	(17,141)	(28,873)	(19,366)	11,732	41%	(9,507)	(49)%
Field operating costs (excluding equity compensation charge)	(183)	(185)	(154)	2	1%	(31)	(20)%
Equity compensation charge - operations (3)	(1)			(1)	N/A		
Segment G&A expenses (excluding equity compensation charge)	(67)	(63)	(52)	(4)	(6)%	(11)	(21)%
Equity compensation charge - general and administrative (3)	(22)	(8)	(17)	(14)	(175)%	9	53%
Segment profit	$ 345	$ 221	$ 269	$ 124	56%	$ (48)	(18)%
Maintenance capital	$ 8	$ 4	$ 6	4	100%	(2)	(33)%
Segment profit per barrel (4)	$ 1.17	$ 0.70	$ 0.86	$ 0.47	67%	$ (0.16)	(19)%

Average Daily Volumes (5) (in thousands of barrels per day)	**For the Year Ended December 31, 2009**	**2008**	**2007**	**Favorable (Unfavorable) 2009-2008 Volumes**	**%**	**2008-2007 Volumes**	**%**
Crude oil lease gathering purchases	612	658	685	(46)	(7)%	(27)	(4)%
Refined products sales	35	26	11	9	35%	15	136%
LPG sales	105	103	90	2	2%	13	14%
Waterborne foreign crude oil imported	55	80	71	(25)	(31)%	9	13%
Supply & Logistics segment total	807	867	857	(60)	(7)%	10	1%

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(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged inventory purchases) of approximately $11 million, $21 million and $44 million for the years ended December 31, 2009, 2008 and 2007, respectively.

(3) Equity compensation expense related to our equity compensation plans.

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

(5) 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.

Table of Contents

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 has a positive impact on our lease gathering margins because crude oil gatherers can capture a premium for prompt deliveries. However, in this environment, there is little incentive to store crude oil as current prices are above future delivery prices. In addition, 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 rates. Our revenues from the supply and logistics segment were unfavorably impacted in 2009 compared to 2008 as a result of the appreciation of the U.S. dollar relative to the Canadian dollar. The average Canadian dollar to U.S. dollar exchange rate for 2009 was $1.14 CAD: $1.00 USD compared to an average of $1.07 CAD: $1.00 USD in 2008 and in 2007.

Operating Revenues and Volume. Revenues net of purchases and related costs increased by approximately 30%, or approximately $141 million, in 2009 as 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) 2008 was negatively impacted by Hurricanes Gustav and Ike (we estimate the negative impact to be approximately $15 million); 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.

Revenues net of purchases and related costs decreased by approximately 3% in 2008 as compared to 2007. The primary reason for the decrease was that 2008 was negatively impacted by Hurricanes Gustav and Ike. We estimate the negative impact to be approximately $15 million. Lease gathering margins were also stronger in 2008 as compared to 2007; however, this was largely offset by a decline in crude oil contango market opportunities in 2008.

Field Operating Costs. Field operating costs (excluding equity compensation charges as discussed below) in 2009 were in line with 2008 costs. Field operating costs were approximately $31 million higher in 2008 than in 2007. Such costs relate primarily to our lease gathering activities where our net revenues (revenues less purchases and related costs) increases more than offset the cost increases in 2008.

General and Administrative Expenses. General and administrative expenses (excluding equity compensation charges as discussed below) increased approximately 6% in 2009 compared to 2008, primarily due to increased payroll and benefit costs. Similarly, such costs increased in 2008 as compared to 2007 due to (i) increased payroll and benefit costs and (ii) a change in allocation methodology between the facilities and supply and logistics segments.

Table of Contents

Equity Compensation Charges. Equity compensation charges increased approximately $15 million in 2009 compared to 2008 and decreased approximately $9 million in 2008 as compared to 2007. Such variations are primarily as a result of an increase in unit price for 2009 relative to 2008 and a decrease in unit price in 2008 relative to 2007. 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 and $52.00 per unit at the end of 2007. The impact of these price fluctuations are partially impacted by additional equity compensation grants during each period (including the Class B grants), changes to our probability assessment that result in accruals for grants that were previously not considered to be probable of vesting and forfeitures. See Note 10 to our Consolidated Financial Statements for additional information on our equity compensation plans.

Maintenance Capital. Maintenance capital consists of capital investments for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production and/or functionality of our existing assets. The increase in maintenance capital 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 $236 million for the year ended December 31, 2009 compared to $211 million and $180 million for the years ended December 31, 2008 and 2007, respectively. The increases in 2009, 2008 and 2007 related primarily to an increased amount of depreciable assets stemming from our acquisition activities and internal growth projects. Amortization of debt issue costs was $6 million, $4 million and $3 million in 2009, 2008 and 2007, respectively.

Included in depreciation expense for the years ended December 31, 2009, 2008 and 2007 is a net loss of $1 million, a net gain of $6 million and a net loss of approximately $7 million, respectively, recognized upon disposition of certain inactive assets. Also included within depreciation expense for the year ended December 31, 2009 and 2008 is an impairment of less than $1 million and $5 million, respectively, for assets taken out of service.

Interest Expense

Interest expense was $224 million for the year ended December 31, 2009, compared to $196 million and $162 million for the years ended December 31, 2008 and 2007, respectively. Interest expense is primarily impacted by:

- our weighted average debt balances;
- the level and maturity of fixed rate debt and interest rates associated therewith;

- market interest rates and our interest rate hedging activities on floating rate debt; and

- interest capitalized on capital projects.

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

	For the year ended December 31,					
	2009		2008		2007	
	Total	% of Total	Total	% of Total	Total	% of Total
Fixed rate senior notes (1)	$ 3,722	95%	$ 3,028	87%	$ 2,625	95%
Borrowings under our revolving credit facilities (2)	207	5%	456	13%	150	5%
Total	$ 3,929		$ 3,484		$ 2,775	

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

(2) Excludes borrowings under our senior secured hedged inventory facility and the short-term portion of our senior unsecured revolving credit facility, as the associated interest expense is recorded in Purchases and related costs on our consolidated income statement.

Table of Contents

The following table summarizes the components impacting the interest expense variance for the years ended December 31, 2009 and 2008 (in millions, except for percentages):

		$	Average LIBOR Rate	Weighted Average Interest Rate (1)
Interest expense for the year ended December 31, 2007	$	162	5.2%	6.3%
Impact of issuance of senior notes (2)		27		
Impact of increased borrowings under credit facilities (3)		5		
Impact of increased capitalized interest		(3)		
Other		5		
Interest expense for the year ended December 31, 2008	$	196	2.7%	5.9%
Impact of retirement of senior notes (4)		(7)		
Impact of issuance of senior notes (5)		53		
Impact of decreased borrowings under credit facilities (3)		(15)		
Impact of decreased capitalized interest		2		
Other		(5)		
Interest expense for the year ended December 31, 2009	$	224	0.3%	6.0%

(1) Excludes commitment and other fees.

(2) The $600 million senior notes were issued in April 2008 in connection with the Rainbow acquisition.

(3) The change primarily reflects varying borrowing requirements for inventory-related borrowings and other working capital items and changes in LIBOR rates. As further discussed below, during 2009 we utilized a portion of our $500 million 4.25% senior notes due 2012 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.

(4) 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.

(5) 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 $1 million for the year ended December 31, 2009.

In April 2008, we completed the issuance of our $600 million 6.5% senior notes due 2018. Therefore, these senior notes were outstanding for approximately eight months of the year compared to twelve months during 2009.

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 $11 million, $21 million and $44 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Other Income, Net

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.

Other income, net for the year ended December 31, 2008, primarily included (i) a gain of $14 million resulting from the sale of our NYMEX seats and shares in NYMEX Holdings, Inc., which merged with CME Group Inc. and (ii) a gain of $11 million on the foreign currency hedge and commodity price risk hedge that we entered into in connection with the Rainbow acquisition.

Income Tax Expense

Our income tax expense decreased by $2 million from $8 million in 2008 to $6 million in 2009 as a result of a decrease of Canadian taxable income.

Excluding the $10 million impact of the initial adoption of the revised Canadian tax laws in 2007, our income tax expense increased by $2 million in 2008 compared to 2007 primarily due to the Rainbow acquisition. Income tax expense was $16 million for the year ended December 31, 2007 primarily due to revised rules on Canadian taxation on certain flow-through entities and the introduction of the Texas margin tax. See Note 7 to our Consolidated Financial Statements for further discussion.

Outlook

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 recent data signal improvements in the health of the

economy have started to occur, while other data 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. Based on data available through early 2010, U.S. demand for petroleum has declined by approximately 10% from levels experienced during the 2005 to 2007 time period and natural gas demand has declined approximately 2% to 3% relative to 2008.

Although we expect that the U.S. economy will ultimately rebound and energy demand will return to a growth profile, these conflicting signals lead us to believe that significant uncertainty remains regarding the timing of the recovery, which translates into potential near-term risks for the energy sector. We will not be unaffected by challenging economic and capital markets conditions, however, 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. However, there can be no assurance that we will not be negatively affected by this volatility or the challenging capital markets conditions, or that our acquisition and expansion efforts will be successful. See Item 1A. Risk Factors - Risks Related to Our Business.

Liquidity and Capital Resources

Cash flow from operations and borrowings under our credit facilities are our primary sources of liquidity. At December 31, 2009, we had approximately $1.0 billion of liquidity available to meet our ongoing operational, investing and finance needs as noted below (in millions):

		As of December 31, 2009
Availability under our senior unsecured revolving credit facility	$	751
Availability under our senior secured hedged inventory facility		200
Cash and cash equivalents		25
Total	$	976

At December 31, 2009, we had a working capital deficit of approximately $124 million. 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 material 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.

Table of Contents

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

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

In periods when the market is not in contango, we typically sell our crude oil during the same month in which we purchase it and we do not rely on borrowings under our credit facilities to pay for the crude oil. 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.

Our cash flow from operations was positively impacted by cash generated by our recurring operations. Our cash flow from operations can be significantly impacted in periods when we are increasing or decreasing the amount of inventory in storage. During 2009, we increased the amount of our inventory. The increase in inventory was due to both increased volumes and an increase in prices and was primarily related to our crude oil contango market storage activities. The net increased levels of inventory were financed through borrowings under our credit facilities and senior note 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 year amounts. 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. The settlement of gains on derivatives that have been deferred in AOCI also had a significant positive impact in 2008 on our operating cash flows. During 2007 we reduced our overall inventory levels as we liquidated inventory that had been stored in the contango market. The proceeds from liquidating the inventory were used to repay borrowings under our credit facilities and favorably impacted our cash flow from operating activities.

Credit Facilities and Long-Term Debt

At December 31, 2009, we had approximately $751 million of available borrowing capacity under our $1.6 billion committed revolving credit facility. Of the capacity we utilized at December 31, 2009, approximately $76 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, among other things, 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. See Note 4 to our Consolidated Financial Statements.

At December 31, 2009, we had approximately $200 million of availability under our $500 million committed hedged inventory facility. The facility s committed amount may be increased to $1.2 billion, subject to obtaining additional commitments from lenders. This facility is a committed working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility are collateralized by the inventory purchased under the facility and the associated accounts receivable, and will be repaid with the proceeds from the sale of such inventory. The facility matures on an annual basis beginning in October 2010.

We also have several issues of senior debt outstanding that total approximately $4.2 billion, excluding premium or discount, and range in size from $150 million to $600 million and mature at various dates through 2037.

Table of Contents

Our credit agreements and the indentures governing our senior notes contain cross-default provisions. A default under our credit facility would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with 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.

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 and contango market activities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under our credit facilities.

We periodically access the capital markets for both equity and debt financing. As of December 31, 2009, approximately $2.0 billion of unsold securities remained available under our shelf registration statement declared effective on December 16, 2009. We also have access to a universal shelf registration statement, 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.

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

2009			2008			2007		
Units		Net Proceeds (1)	Units		Net Proceeds (1)	Units		Net Proceeds (1)
11,040,000	$	456	6,900,000	$	315	6,296,172	$	383

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

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

Year	Description	Maturity		Face Value		Net Proceeds(1)
2009	5.75% Senior Notes issued at 99.523% of face value (2)	January 2020	$	500	$	494
	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	$	347
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, 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).

On August 15, 2009, our $175 million senior notes matured. We utilized cash on hand and available capacity under our credit facilities to retire these senior notes.

Credit Facilities. During the year ended December 31, 2009, we had net borrowings on our revolving credit facility and our hedged inventory facility of approximately $1 million. During the year ended December 31, 2008, we had net working capital and hedged inventory borrowings of approximately $90 million. These net borrowings were used primarily for purchases of LPG inventory that was stored. During the year ended December 31, 2007, we had net working capital and hedged inventory repayments of approximately $54 million. These repayments resulted primarily from sales of crude oil inventory that was stored and subsequently liquidated as we transitioned to backwardated market conditions, partially offset by higher levels of stored LPG inventory. See Cash Flow from Operations above.

Capital Expenditures and Distributions Paid to Our Unitholders and General Partner

We use cash primarily for our acquisition activities, internal growth projects and distributions paid to our unitholders and general partner. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations and the financing activities discussed above. 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.

2010 Capital Expansion Projects. The majority of funding for our 2010 capital program will be provided by revolver borrowings and cash flow in excess of partnership distributions. This will allow us to fund these capital projects without need to access the capital markets for equity or debt. Our 2010 capital expansion program includes the following projects with the estimated cost for the entire year (in millions):

Projects	**2010**	
Patoka - Phase III	$	24
West Texas gathering lines		18
Bumstead facility upgrade		17
Cushing - Phase VII		17
Cushing - Phase VIII		15
St. James - Phase III		15
Wichita Falls tanks		11
Martinez tanks		9
Other projects, including acquisition related expansion projects (1)		234
	$	360

(1) Primarily consists of gas storage construction projects, pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2009.

Distributions to unitholders and general partner. We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. On February 12, 2010, we paid a quarterly distribution of $0.9275 per limited partner unit. This distribution represented a year-over-year distribution increase of approximately 3.9%. 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.

Table of Contents

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

See Note 11 to our Consolidated Financial Statements.

Commitments

Contractual Obligations. In the ordinary course of doing business we purchase crude oil and LPG from third parties under contracts, the majority of which range in term from thirty-day evergreen to three years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between 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 creditworthy entities.

The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of December 31, 2009 (in millions):

	Total	2010	2011	2012	2013	2014	2015 and Thereafter
Long-term debt and interest payments(1)	$ 7,150	$ 66	$ 260	$ 260	$ 950	$ 472	$ 5,142
Leases (2)	491	79	62	54	33	23	240
Other long-term liabilities(3)	234	118	25	22	23	3	43
Subtotal	7,875	263	347	336	1,006	498	5,425
Crude oil, LPG and other purchases(4)	5,429	4,201	820	379	16	2	11
Total	$ 13,304	$ 4,464	$ 1,167	$ 715	$ 1,022	$ 500	$ 5,436

(1) Includes debt service payments, interest payments due on our senior notes and the commitment fee on our revolving credit facility. Although there is an outstanding balance on our revolving credit facility at December 31, 2009, 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 and (iv) trucks used in our gathering activities.

(3) Excludes a non-current liability of approximately $35 million related to derivative activity included in crude oil and LPG purchases.

(4) Amounts are based on estimated volumes and market prices. The actual physical volume purchased and actual settlement prices 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, 2009 and 2008, we had outstanding letters of credit of approximately $76 million and $51 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 307 of Regulation S-K.

Table of Contents

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, 2009 (unaudited, dollars in millions):

Entity	Type of Operation	Our Ownership Interest	Total Entity Assets	Total Cash and Restricted Cash	Total Entity Debt
Settoon Towing	Barge Transportation Services	50%	$ 92	$	$ 53
Frontier	Crude Oil Pipeline	22%	$ 27	$ 3	$
Butte	Crude Oil Pipeline	22%	$ 19	$ 5	$

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. We utilize various derivative instruments to manage such exposure and, in certain circumstances, to realize incremental margin during volatile market conditions. In analyzing our risk management activities, we draw a distinction between enterprise level risks and trading related risks. Enterprise level risks are those that underlie our core businesses and may be managed based on whether there is value in doing so. Conversely, trading related risks (the risks involved in trading in the hopes of generating an increased return) are not inherent in the our 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 interest rates, currency exchange rates, NYMEX, ICE and over-the-counter positions, and physical volumes, grades, locations and delivery schedules to ensure our hedging activities address our market risks. We have a risk management function that has direct responsibility and authority for our risk policies, 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. Our approved strategies are intended to mitigate and manage enterprise level risks that are inherent in our core businesses. To hedge the risks discussed above, we engage in risk management activities that we categorize by the risks we are hedging. The following discussion addresses each category of risk.

Commodity Price Risk

We use derivative instruments and physical delivery contracts 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 consist primarily of futures, options and swaps traded on the NYMEX and ICE and in over-the-counter transactions, including swaps and options contracts. Our policy is to purchase only commodity products for which we have a market, and to structure our sales contracts so that price fluctuations for those products do not materially affect the segment profit we earn. We do not acquire and hold futures contracts or physical commodities for the purpose of speculating on price changes, as these activities could expose us to significant losses.

Although we seek to maintain a position that is substantially balanced within our various commodity purchase and sales activities, we may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. 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.

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

All of our open commodity price risk derivatives at December 31, 2009 were categorized as non-trading. The fair value of these instruments and the change in fair value that would be expected from a 10% price decrease is shown in the table below (in millions):

Table of Contents

	Fair Value	Effect of 10% Price Decrease
Crude oil:		
Futures contracts	$ 39	$ 82
Swaps and options contracts	(14)	$ 27
LPG and other:		
Futures contracts	(13)	
Swaps and options contracts (1)	(16)	$ (13)
Total Fair Value	$ (4)	

(1) Amount includes a liability of approximately $7 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 contracts 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. These quotes are compared to the contract price of the swap, which approximates the gain or loss that would have been realized if the contracts had been closed out at year end. For positions where independent quotations are not available, an estimate is provided, or the prevailing market price at which the positions could be liquidated is used. The assumptions used in these estimates as well as the source for the estimates are maintained by the independent risk control function. See Note 6 to our Consolidated Financial Statements for further discussion. Price-risk sensitivities were calculated by assuming an across-the-board 10% 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 obligations on specific debt issuances, including anticipated debt issuances. All of our senior notes are fixed rate notes and thus not subject to market risk. Substantially all of our variable rate debt at December 31, 2009, approximately $1.4 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 1.3% is based upon rates in effect at December 31, 2009. The fair value of our interest rate derivatives is an unrealized gain of approximately $2 million as of December 31, 2009. A 10% decrease in the forward LIBOR curve as of December 31, 2009 would result in an increase of approximately $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 Risk

Our cash flow stream relating to our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. Because a significant portion of our Canadian business is conducted in Canadian dollars, we use certain financial instruments to minimize the risks associated with our exposure to fluctuations in the U.S Dollar-to-Canadian Dollar exchange rate. These instruments primarily include forward exchange contracts, foreign currency forwards and options. The fair value of these instruments is an unrealized gain of approximately $1 million as of December 31, 2009. A 10% decrease in the exchange rate (Canadian dollars to U.S. dollars) would result in an increase of approximately $8 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.

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

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

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

None.

Table of Contents

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

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

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our DCP as of the end of the period covered by this report. Based on this review, our Chief Executive Officer and Chief Financial Officer have 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.

Changes in Internal Control over Financial Reporting

In addition to the information concerning our DCP, we are required to disclose certain changes in our internal control over financial reporting. Although we have made various enhancements to our controls, there 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.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, our Chief Executive Officer and our Chief Financial Officer, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our management, including our Chief Executive Officer and our Chief Financial Officer, has evaluated the effectiveness of our internal control over financial reporting as of December 31, 2009. See Management s Report on Internal Control Over Financial Reporting on page F-2.

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

There was no information that was required to be disclosed in a report on Form 8-K during the fourth quarter of 2009 that has not previously been reported.

Table of Contents

PART III

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

Partnership Management and Governance

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

Our general partner manages our operations and activities. Unitholders are limited partners and do not directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to our unitholders, as limited by our partnership agreement. As a general partner, our general partner is liable for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Our general partner has the sole discretion to incur indebtedness or other obligations on our behalf on a non-recourse basis to the general partner. Our general partner has in the past exercised such discretion, 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 Fourth Amended and Restated Limited Liability Company Agreement of GP LLC (the GP LLC Agreement), two 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 five seats are elected, and may be removed, by a majority of the membership interest. Directors filling three of these five 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. One of the members of GP LLC, a wholly owned subsidiary of Occidental Petroleum Corporation (Oxy), has the right to designate an individual to attend Board meetings in an observer capacity. Under certain circumstances involving changes in senior-most management, Oxy will have the right to designate a director to serve on the Board and the authorized number of Board members will be expanded to a total of nine.

In connection with a transaction in which it increased its ownership to greater than 50%, Vulcan Energy entered into an agreement with GP LLC pursuant to which Vulcan Energy has agreed to restrict certain of its voting rights to help preserve a balanced board. Vulcan Energy has agreed that, with respect to any action taken involving the election or removal of an independent director serving on our audit committee, Vulcan Energy will vote all of its interest in excess of 49.9% in the same way and proportionate to the votes of all membership interests other than Vulcan Energy s. Without the voting rights agreement, Vulcan Energy s ownership interest would, in effect, allow Vulcan Energy unilaterally to elect the Vulcan Energy designee and the five at large seats (subject to the requirement that three of the at large directors meet the independence requirements set forth in the GP LLC Agreement, our partnership agreement, NYSE listing standards and SEC regulations). Vulcan Energy has the right at any time to give notice of termination of the voting rights agreement. The time between notice and termination depends on the circumstances, but would never be longer than one year. In connection with Vulcan Energy s entry into the voting rights agreement, Messrs. Armstrong and Pefanis entered into waivers of the change in control provisions of their employment agreements, which otherwise would have been triggered by the transaction in which Vulcan Energy obtained the additional interest. These waivers were contingent upon Vulcan s execution of the voting rights agreement, and will terminate upon any breach or termination by Vulcan Energy of, or notice of termination under, the voting rights agreement. See Item 11. Executive Compensation Employment Contracts and Potential Payments upon Termination or Change-in-Control.

Table of Contents

Another member of GP LLC, Lynx Holdings I, LLC, has also agreed to certain restrictions on its voting rights with respect to its approximate 1.4% interest in GP LLC and AAP LP. The Lynx voting rights agreement requires Lynx to vote its membership interest (in the context of the election or the removal of an independent director serving on our audit committee) in the same way and proportionate to the votes of the other membership interests (excluding Vulcan s and Lynx s). Lynx has the right to terminate its voting rights agreement at any time upon termination of the Vulcan voting rights agreement or the sale or transfer of all of its interest in the general partner to an unaffiliated third party.

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 offers 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 or a nominating or compensation committee of the board of directors. 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.

Under NYSE listing standards, to be considered independent, our board of directors must determine that a director has no material relationship with us other than as a director. The standards specify the criteria by which the independence of directors will be determined, including guidelines for directors and their immediate family members with respect to employment or affiliation with us or with our independent public accountants. The board of directors has determined that Messrs. Goyanes, Petersen, Smith, 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 (Everardo Goyanes, Arthur L. Smith and J. Taft Symonds) is (i) independent under applicable NYSE rules and (ii) an Audit Committee Financial Expert, as that term is defined in Item 407 of Regulation S-K.

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

Table of Contents

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 2009, the amount paid to LEH by Plains Marketing was approximately $0.2 million (net of severance taxes). The board has determined that the transactions with LEH do not compromise Mr. Goyanes independence.

Arthur L. Smith, a member of our audit committee, is a director of Pioneer Natural Resources GP LLC, the general partner of Pioneer Southwest Energy Partners, L.P. (PSE). PSE is a subsidiary of Pioneer Natural Resources Company (Pioneer). Pioneer and its affiliates (including PSE) own crude oil producing properties in the Permian Basin of Texas and New Mexico, from which Plains Marketing gathers and markets the petroleum production. Mr. Smith is not an officer of PSE or Pioneer and does not participate in operational decision making. In 2009, the amount paid to Pioneer and its affiliates for petroleum gathered and marketed by Plains Marketing was approximately $302 million. The board has determined that the transactions with PSE and Pioneer do not compromise Mr. Smith s 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.

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

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 Geoff McKay, Gary R. Petersen and Robert V. Sinnott. 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 2009. Similarly, the compensation committee has not delegated any of its authority to subcommittees. The compensation committee has delegated limited authority to the CEO to administer our long-term incentive plans with respect to employees other than executive officers.

Governance and Other Committees

We also have a governance committee that periodically reviews our governance guidelines. The charter of our governance committee is available on our website. See Meetings and Other Information for information on how to access or obtain copies of this charter. The governance committee currently consists of Messrs. Smith and Symonds, each of whom is independent under the NYSE s listing standards. As a limited partnership, we are not required by the listing standards of the NYSE to have a nominating committee. As discussed above, two 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 the currently vacant at large seat. The governance committee will base its recommendations on an assessment of the skills, experience and characteristics of the candidate in the context of the needs of the board. The governance committee does not have a policy with regard to the consideration of diversity in identifying director nominees; therefore, diversity may or may not be considered in connection with the assessment process. As a minimum requirement for the three required independent board seats, any candidate must be independent and qualify for service on the audit committee under applicable SEC and NYSE rules, the GP LLC Agreement and our partnership agreement.

In addition, our partnership agreement provides for the establishment or activation of a conflicts committee as circumstances warrant to review conflicts of interest between us and our general partner or the owners of our general partner. Such a committee will typically consist of a minimum of two members, none of whom can be

Table of Contents

officers or employees of our general partner or directors, officers or employees of its affiliates or 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 four meetings, our audit committee had eight meetings, our compensation committee had one formal meeting and our governance committee had two 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 partnership and directors of GP LLC are designated or elected by the members of GP LLC. Accordingly, unlike holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement. As a result, we do not hold annual meetings of unitholders.

All of our 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 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, 2009 for filing with the SEC.

Table of Contents

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

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. Two 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 12/31/09)	Position(1)
Greg L. Armstrong*(2)	51	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis*	52	President and Chief Operating Officer
Phillip D. Kramer*	53	Executive Vice President
W. David Duckett*	54	President PMC (Nova Scotia) Company
Mark J. Gorman*	55	Senior Vice President Operations and Business Development
Alfred A. Lindseth	40	Senior Vice President Technology, Process & Risk Management
Al Swanson*	45	Senior Vice President and Chief Financial Officer
John P. vonBerg*	55	Senior Vice President Commercial Activities
Stephen L. Bart	49	Vice President Operations of PMC (Nova Scotia) Company
Samuel N. Brown	53	Vice President Pipeline Business Development
David Craig	52	Executive Vice President and Chief Financial Officer of PMC (Nova Scotia) Company
Ralph R. Cross	54	Vice President Corporate Development and Transportation Services of PMC (Nova Scotia) Company
A. Patrick Diamond	37	Vice President
Lawrence J. Dreyfuss	55	Vice President, General Counsel Commercial & Litigation and Assistant Secretary
Roger D. Everett	64	Vice President Human Resources
James B. Fryfogle	58	Vice President Refinery Supply
M.D. (Mike) Hallahan	49	Vice President Crude Oil of PMC (Nova Scotia) Company
Bill Harradence	56	Vice President Human Resources of PMC (Nova Scotia) Company
Jim G. Hester	50	Vice President Acquisitions
John Keffer	50	Vice President Terminals
Charles Kingswell-Smith	58	Vice President and Treasurer
Gregg McClement	41	Vice President Business Development LPG of PMC (Nova Scotia) Company
Mike Mikuska	41	Vice President Business Development of PMC (Nova Scotia) Company
Tim Moore*	52	Vice President, General Counsel and Secretary
Daniel J. Nerbonne	52	Vice President Engineering
John F. Russell	61	Vice President West Coast Projects
Robert M. Sanford	60	Vice President Lease Supply
Tina L. Summers*	40	Vice President Accounting and Chief Accounting Officer
Troy E. Valenzuela	48	Vice President Environmental, Health and Safety

Table of Contents

Sandi Wingert	39	Vice President Accounting of PMC (Nova Scotia) Company
David E. Wright	64	Vice President
Ron F. Wunder	41	Vice President LPG of PMC (Nova Scotia) Company
Everardo Goyanes	65	Director and Member of Audit** Committee
Geoff McKay(2)	42	Director and Member of Compensation Committee
Gary R. Petersen	63	Director and Member of Compensation Committee
Robert V. Sinnott(2)	60	Director and Member of Compensation** Committee
Arthur L. Smith	57	Director and Member of Audit and Governance** Committees
J. Taft Symonds	70	Director and Member of Audit and Governance Committees
Christopher M. Temple	42	Director

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

** Indicates chairman of committee.

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

(2) The GP LLC Agreement specifies that the Chief Executive Officer of the general partner will be a member of the board of directors. The GP LLC Agreement also provides that two of the owners of our general partner each have the right to appoint a member of our board of directors. Mr. McKay has been appointed by Vulcan Energy Corporation, of which he is Chairman of the Board. Mr. Sinnott has been appointed by KAFU Holdings, L.P., which is affiliated with Kayne Anderson Investment Management, Inc., of which he is President. 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 also a director of National Oilwell Varco, Inc. and PNGS GP LLC, the general partner of PAA Natural Gas Storage, L.P. Mr. Armstrong previously served as a director of BreitBurn Energy Partners, L.P.

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

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.

Table of Contents

W. David Duckett has served as President of PMC (Nova Scotia) Company since June 2003, and Executive Vice President of PMC (Nova Scotia) Company from July 2001 to June 2003. Mr. Duckett was with CANPET Energy Group Inc. (CANPET) from 1985 to 2001, where he served in various capacities, including most recently 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.

Al Swanson has served as Senior Vice President and Chief Financial Officer since November 2008. He previously served 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 a director of PNGS GP LLC.

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

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

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 served Duke Energy Transport and Trading Company.

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

Table of Contents

Ralph R. Cross has served as Vice President Corporate Development and Transportation Services of PMC (Nova Scotia) Company 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. 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 PMC (Nova Scotia) Company 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.

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

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.

Table of Contents

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 PMC (Nova Scotia) Company 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 PMC (Nova Scotia) Company 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.

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

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

Sandi Wingert has served as Vice President Accounting of PMC (Nova Scotia) Company since February 2008. She has been with PMC and its predecessor CANPET for eight years acting as Controller. Prior to joining our Canadian operations, she held various accounting roles with Koch Petroleum and Ernst & Young.

Table of Contents

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

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

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.

Geoff McKay has served as a director of our general partner since February 2010. Mr. McKay is a Managing Director at Vulcan Capital, the private investment group of Vulcan Inc. He also sits on the boards of Vulcan Energy GP Holdings Inc. and Vulcan Energy Corporation. From March 2000 until joining Vulcan in May 2007, Mr. McKay worked for Forstmann Little & Co., a New York based private equity firm, serving as a general partner from January 2004 to March 2007. During his tenure at Forstmann Little, Mr. McKay was involved with the acquisition and oversight, and served on the boards of directors, of IMG Worldwide, 24 Hour Fitness and ENK International. From 1997 until 2000, he was an investment banker with Goldman Sachs in the mergers and acquisitions group. Mr. McKay currently sits on the boards of TowerCo LLC, ICAT Holdings and Silvercrest Asset Management Group. Mr. McKay holds a BA in Economics from the University of Victoria and an MBA from the Wharton School of the University of Pennsylvania. Mr. McKay has been designated to serve on our Board by Vulcan Energy, pursuant to the power granted under our LLC Agreement. We believe that his substantial transactional experience offers a significant knowledge resource as we pursue our acquisition strategy, and that his investment oversight background and service on other boards will lend critical perspective 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. Mr. Petersen holds BBA and MBA degrees 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 $7 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.

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

Table of Contents

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.

Arthur L. Smith has served as a director of our general partner or former general partner since February 1999. Mr. Smith is President and Managing Member of Triple Double Advisors, LLC, an investment advisory firm focused on the energy industry. Mr. Smith was Chairman and CEO of John S. Herold, Inc. (a petroleum research and consulting firm) from 1984 to 2007. From 1976 to 1984, Mr. Smith was a securities analyst with Argus Research Corp., The First Boston Corporation and Oppenheimer & Co., Inc. Mr. Smith holds the CFA designation. He serves on the board of non-profit Dress for Success Houston and the Board of Visitors for the Nicholas School of the Environment at Duke University. He is a director of Pioneer Natural Resources GP LLC, the general partner of Pioneer Southwest Energy Partners, L.P. Mr. Smith received a BA from Duke University and an MBA from NYU s Stern School of Business. The Board of Directors has determined that Mr. Smith 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. Smith has more than 30 years of extensive and intensive experience in the energy sector as an oil analyst, prior board member (Parker & Parsley Petroleum Company, Cabot Oil & Gas Corporation, Evergreen Resources, Inc. and the New York Society of Security Analysts) and industry observer. His acute knowledge of the industry and his executive background provide a critical resource and skill set to the Board.

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. 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. 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 also sits on the boards of Vulcan Energy GP Holdings Inc., Vulcan Energy Corporation and Charter Communications Inc. 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 partner at Thayer Capital Partners. Additionally, Mr. Temple was a licensed CPA serving clients in the energy sector with KPMG in Houston, Texas. 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. 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.*

Table of Contents

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 2009, except as follows: Mr. Symonds inadvertently filed a late Form 4 in connection with the purchase by his wife s trust of PAA units on August 25, 2008. The Form 4 was filed on March 27, 2009.

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 the reviews and discussions referred to above, the compensation committee recommended to the board of directors that the compensation discussion and analysis be included in the Annual Report on Form 10-K for the year ended December 31, 2009 for filing with the SEC.

Robert V. Sinnott, *Chairman*
Gary R. Petersen
T. Geoff McKay
Christopher M. Temple (former member)

Compensation Committee Interlocks and Insider Participation

Messrs. McKay, Petersen and Sinnott currently serve on the compensation committee. Messrs. Petersen, Sinnott and Temple served on the compensation committee during 2009. W. Lance Conn, a former director, served on the compensation committee for a portion of 2009. During 2009, 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, and Messrs. Conn and Temple were formerly associated, with Vulcan Energy and its affiliates, with which we have relationships. See Item 13. Certain Relationships and Related Transactions, and Director Independence.

Compensation Discussion and Analysis

Background

All of our officers and employees (other than Canadian personnel) are employed by Plains All American GP LLC. Our Canadian personnel are employed by PMC (Nova Scotia) Company, which is a wholly owned subsidiary. Under our partnership agreement, we are required to reimburse our general partner and its affiliates for all employment related costs, including compensation for executive officers, 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 unitholders, and at the same time enables us to maintain a lower level of base overhead in the event our operating and financial performance is below expectations. Our executive compensation is designed to attract and retain individuals with the background and skills necessary to successfully execute our business model in a demanding environment, to motivate those individuals to reach near-term and long-term goals in a way that aligns their interest with that of our unitholders, and to reward success in

Table of Contents

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 partnership (MLP) peers, but are moderate relative to the broad spectrum of energy industry competitors for similar talent.

Cash Bonuses. Our cash bonuses consist of annual discretionary bonuses in which all of our current domestic Named Executive Officers potentially participate and a formula-based quarterly bonus program in which Mr. vonBerg was eligible to participate in 2009, 2008 and 2007. Mr. Duckett participates in a formula-based quarterly and annual bonus program specific to activities managed by our Canadian personnel.

Long-Term Incentive Awards. The primary long-term measure of our performance is our ability to increase our sustainable quarterly distribution to our unitholders. Historically, we have used performance-indexed phantom unit grants to encourage and reward timely achievement of targeted distribution levels and align the long-term interests of our Named Executive Officers with those of our unitholders. These grants also 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 12, 2010, approximately 25% of the outstanding Class B units granted prior to 2009 had been earned and none of the Class B units granted in 2009 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. 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 or Plains AAP, L.P. elects not to timely exercise its call right. See Item 13. Certain Relationships and Related Transactions, and Director Independence Transactions with Related Persons Our General Partner Class B Units of Plains AAP, L.P.

Relation of Compensation Elements to Compensation Objectives

Our compensation program is designed to motivate, reward and retain our executive officers. Cash bonuses serve as a near-term motivation and reward for achieving the annual goals established at the beginning of each year. Phantom unit awards (and associated DERs) and Class B units provide motivation and reward over both the near-term and long-term for achieving performance thresholds necessary for earning and vesting. The level of annual bonus and phantom unit awards reflect the moderate salary profile and the significant weighting towards performance based, at-risk compensation. Salaries and cash bonuses (particularly quarterly bonuses), as well as currently payable DERs associated with unvested phantom units and earned Class B units subject to Plains AAP, L.P. s call right, serve as near-term retention tools. Longer-term retention is facilitated by the minimum service periods of up to five years associated with phantom unit awards, the long-term (January 2016) vesting profile of the Class B units and, in the case of certain executives directly involved in activities that generate partnership earnings, annual bonuses that are payable over a three-year period. To facilitate Plains All American GP LLC s compensation committee in reviewing and making recommendations, a compensation tally sheet is prepared by Plains All American GP LLC s 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, 2009, our annual distribution per common unit has grown at a compound annual rate of 8.5% and the total return realized by our unitholders for that period averaged approximately 14.5%. 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 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, 2009, 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, our distribution growth targets and other quantitative and qualitative goals established at the beginning of each year. Such annual objectives are discussed and reviewed with the board of directors in conjunction with the review and authorization of the annual plan.

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

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

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

U.S. Bonus based on Adjusted EBITDA. Mr. vonBerg and certain other members of our U.S. based senior management team are directly involved in activities that generate partnership earnings. These individuals, along with other employees in our marketing and business development groups participate in a quarterly bonus pool based on adjusted EBITDA, which directly rewards for quarterly performance the commercial and asset managing employees who participate. This quarterly incentive provides a direct incentive to optimize quarterly performance even when, on an annual basis, other factors might negatively affect bonus potential. Allocation of quarterly bonus amounts among all participants based on relative contribution is recommended to or by Mr. Pefanis and reviewed, modified and approved by Mr. Armstrong, as appropriate. Messrs. Pefanis and Armstrong do not participate in the quarterly bonus. 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 PMC (Nova Scotia) Company (including Mr. Duckett) or involved in Canadian operations participate in a bonus pool under a program established at the time of our entry into Canada in 2001 in connection with the CANPET acquisition. The program encompasses a bonus pool consisting of 10% of Adjusted EBITDA for Canadian-based operations (reduced by the carrying cost of inventory in excess of base-level requirements and by the cost of capital associated with growth capital and acquisitions). Participation in the program is recommended by Mr. Duckett and reviewed, adjusted if warranted, and approved by Mr. Pefanis. Mr. Pefanis does not participate in the program. Mr. Duckett receives a quarterly bonus equal to approximately 40% of his participation level for the first three fiscal quarters of the year. He receives an annual bonus consisting of 60% of his participation in the first three quarters and 100% of his participation in the fourth quarter.

Long-Term Incentive Awards. We do not make systematic annual phantom unit awards to our Named Executive Officers. Instead, our objective is to time the granting of awards such that as performance thresholds are met for existing awards, additional long-term incentives are created. Thus, performance is rewarded by relatively greater frequency of awards and lack of performance by relatively lesser frequency of awards. Generally, we believe that a 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

Table of Contents

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 165,500 were issued as of December 31, 2009 pursuant to individual restricted units agreements between Plains AAP, L.P. and certain members of management. As of December 31, 2009 our Named Executive Officers held 111,000 of the restricted Class B units. The remaining available Class B units are administered at the discretion of the compensation committee and may be awarded upon advancement, exceptional performance or other change in circumstance of an existing member of management, or upon the addition of a new individual to the management team.

Application in 2009

At the beginning of 2009, 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 2009 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 2009 capital program and set the stage for continued growth in 2010;

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

4. Prudently manage our capital resources and preserve our strong capitalization and liquidity.

Our two internal qualitative goals included (i) the continued implementation and expansion of our asset integrity management program with respect to assets not yet covered or only partially covered by regulatory mandate and improvement of our safety performance, and (ii) maintaining and improving communication throughout the organization.

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

With respect to our four public goals:

1. Excluding the benefit of unforecasted acquisitions completed during the year, our adjusted EBITDA exceeded the high end of our original guidance for 2009;

2. We began the year with a $295 million capital program that was expanded during the year to $380 million. As capital markets improved throughout the year, new projects were added that exceeded our threshold return criteria or were added as a result of acquisitions made during the year. Projects were generally completed timely and cost-effectively;

3. We completed the acquisition of the remaining 50% interest in PNGS for an aggregate purchase price of $215 million. We also completed six other acquisitions for aggregate consideration of approximately $180 million, which primarily consisted of pipeline and storage facilities that complemented our existing asset base and business activities. Our three-year average acquisition expenditures total approximately $418 million per year; and

Table of Contents

4. During the year, we raised approximately $1.8 billion in both long-term debt and equity in five different transactions and renewed our $500 million hedged inventory facility on favorable terms. We ended 2009 with a strong balance sheet, solid credit metrics and approximately $975 million of committed liquidity.

During 2009, we continued to expand, implement and develop our integrity management and maintained communication throughout the organization. We also increased our annualized distribution rate by 3.6% to $3.68 per common unit, while generating aggregate annual distribution coverage of over 110%.

For 2009, the elements of compensation were applied as follows:

Salary. In February 2009, the annual salary of each of Mr. vonBerg and Mr. Swanson was increased to $250,000. No other salary adjustments for Named Executive Officers were recommended or made in 2009. 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 each of the four goals established for 2009; 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 40% in annual bonus and 60% in quarterly bonus.

Long-Term Incentive Awards. In February 2009, Mr. Swanson was awarded 35,000 phantom units under our LTIP. Such award was related to Mr. Swanson s promotion to Chief Financial Officer in November 2008. There were no other grants of long-term incentive awards to Named Executive Officers in 2009. See Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table.

The last grant cycle of equity awards to Named Executive Officers occurred in 2007. The performance threshold for vesting in one-third of the 2007 grants has been met, and the second performance threshold is expected to be reached in 2010. 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. Additionally, the highest and last performance threshold for the 2005 grant cycle has been met, and final vesting of such grants will occur in May 2010.

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 February 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. These phantom units 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.

Any of these 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; and Mr. Duckett, 75,000.

Other Compensation Related Matters

Equity Ownership in PAA. As of December 31, 2009, 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, 2009, our Named Executive Officers beneficially owned, in the aggregate, approximately 755,711 of our common units (excluding any unvested equity awards), an approximately 2.4% indirect ownership interest in our general partner and IDRs, and 111,000 Class B units of Plains AAP, L.P. Based on the market price of our common units at December 31, 2009 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 2009.

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

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

Change in Control Triggers. The employment agreements for Messrs. Armstrong and Pefanis, the long-term incentive plan grants to our Named Executive Officers, and the Class B restricted units agreements include severance payment provisions or accelerated vesting triggered upon a change of control, as defined in the respective agreement. In the case of the long-term incentive plan grants, the provision becomes operative only if the change in control is accompanied by a change in status (such as the termination of employment by Plains All American GP LLC). We believe this double trigger arrangement is appropriate because it provides assurance to

Table of Contents

the executive, but does not offer a windfall to the executive when there has been no real change in employment status. The provisions in the employment agreements for Messrs. Armstrong and Pefanis become operative only if the executive terminates employment within three months of the change in control. Messrs. Armstrong and Pefanis agreed to a conditional waiver of these provisions with respect to a sale transaction in August 2005 that would have constituted a change in control. 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). See Employment Contracts and Potential Payments upon Termination or Change-in-Control.

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 Crude Oil Volatility; Counter-Cyclical Balance; 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 three other most highly compensated executive officers in 2009 (our Named Executive Officers). We reimburse our general partner and its affiliates for expenses incurred on our behalf, including the costs of officer compensation (excluding the costs of the obligations represented by the Class B units).

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)(1)	All Other Compensation ($)(2)	Total ($)
Greg L. Armstrong	2009	375,000	3,000,000		15,800	3,390,800
Chairman and CEO	2008	375,000	2,900,000		14,775	3,289,775
	2007	375,000	3,400,000	2,770,660	14,430	6,560,090
Harry N. Pefanis	2009	300,000	2,900,000		15,800	3,215,800
President and Chief Operating	2008	300,000	2,800,000		14,775	3,114,775
Officer	2007	300,000	3,200,000	1,958,805	14,430	5,473,235
Al Swanson	2009	250,000	1,000,000	376,483	15,763	1,642,246
Senior Vice President and	2008	180,000	700,000		14,502	894,502
Chief Financial Officer						
W. David Duckett(3)	2009	251,058	3,378,240		83,643	3,712,941
President PMC (Nova Scotia)	2008	268,095	2,915,424		88,831	3,272,350
Company	2007	266,960	3,028,488	1,177,531	93,501	4,566,480
John P. vonBerg	2009	250,000	3,220,000(4)		15,800	3,485,800
Senior Vice President	2008	200,000	2,740,000(4)		14,580	2,954,580
Commercial Activities	2007	200,000	2,765,000(4)	969,731	14,244	3,948,975

Table of Contents

(1) Dollar amounts represent the aggregate grant date fair value of phantom units and Class B units granted during each year based on the probable outcome of underlying performance conditions. For phantom units granted in 2007 and 2009, the performance threshold for the first tranche of vesting was deemed probable of occurrence as of the grant date. For Class B units granted in 2007, the performance threshold for the first tranche of earning was deemed probable of occurrence as of the grant date. The maximum grant date fair values of stock awards assuming that the highest level of performance conditions will be met are as follows:

Name	Year	Maximum Grant Date Fair Value ($)
Greg L. Armstrong	2009	
	2008	
	2007	17,544,186
Harry N. Pefanis	2009	
	2008	
	2007	12,425,957
Al Swanson	2009	1,129,450
	2008	
W. David Duckett	2009	
	2008	
	2007	7,383,061
John P. VonBerg	2009	
	2008	
	2007	5,701,156

(2) Plains All American GP LLC matches 100% of employees contributions to its 401(k) plan in cash, subject to certain limitations in the plan. All Other Compensation for each of Messrs. Armstrong, Pefanis, Swanson and vonBerg includes $14,700 in such contributions for 2009. The remaining amount for each represents premium payments on behalf of such Named Executive Officer for group term life insurance. All Other Compensation for Mr. Duckett includes, for 2009, employer contributions to the PMC (Nova Scotia) Company savings plan of $32,638, group term life insurance premiums of $16,220, automobile lease payments of $29,143 and club dues.

(3) Salary, bonus and all other compensation amounts for Mr. Duckett are presented in U.S. dollar equivalent based on the exchange rates in effect on the dates payments were made or approved.

(4) Includes quarterly bonuses aggregating $1,920,000, $1,440,000 and $1,765,000 and annual bonuses of $1,300,000, $1,300,000 and $1,000,000 in 2009, 2008 and 2007, respectively. The annual bonuses are payable 60% at the time of award and 20% in each of the two succeeding years.

Table of Contents

Grants of Plan-Based Awards Table

The following table sets forth summary information regarding all grants of plan-based awards made to our Named Executive Officers during the fiscal year ended December 31, 2009.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Stock Awards: Number Of Shares Of Stock or Units	All Other Option Awards: Number Of Securities Underlying Options	Exercise or Base Price Of Option Awards	Grant Date Fair Value Of Stock and Option Awards
Name	**Grant Date**	**Threshold ($)**	**Target ($)**	**Maximum ($)**	**Threshold ($)**	**Target ($)**	**Maximum ($)**	**(#)**	**(#)**	**($/Sh)**	**($)**
Greg L. Armstrong											
Harry N. Pefanis											
Al Swanson	2/19/09							35,000(1)			$ 376,483(2)
W. David Duckett											
John D. vonBerg											

(1) These phantom units will vest in one-third increments as follows: one-third will vest upon the later of the May 2011 distribution date and the date on which we pay a quarterly distribution of at least $0.9375; one-third will vest upon the later of the May 2012 distribution date and the date on which we pay a quarterly distribution of at least $1.00; and one-third will vest upon the later of the May 2013 distribution date and the date on which we pay a quarterly distribution of at least $1.0625. DERs associated with these units become payable in one-third increments upon achieving quarterly distribution levels of $0.9125, $0.9375 and $1.00 per unit, respectively. Any phantom units that have not vested (and all associated DERs) as of the May 2015 distribution date will expire.

(2) Represents the grant date fair value of phantom units based on the probable outcome of underlying performance conditions. The performance threshold for the first one-third vesting was deemed probable of occurrence as of the grant date. The maximum grant date fair value of these phantom units assuming that the highest level of performance conditions will be met is $1,129,450.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

A discussion of 2009 salaries and bonuses is included in Compensation Discussion and Analysis. The following is a discussion of other material factors necessary to an understanding of the information disclosed in the Summary Compensation Table and under Grants of Plan-Based Awards Table above.

Salary As discussed in this Item 11, we do not make systematic annual adjustments to the salaries of our Named Executive Officers. In that regard, no salary adjustments were made for any of our Named Executive Officers in 2009, other than Mr. vonBerg and Mr. Swanson whose salaries were increased to $250,000 each.

Grants of Plan-Based Awards In February 2009, Mr. Swanson was awarded 35,000 phantom units under our LTIP. In February 2010, our Named Executive Officers were awarded the following phantom units: Mr. Armstrong, 180,000; Mr. Pefanis, 120,000; Mr. Swanson, 60,000; Mr. Duckett, 75,000; and Mr. vonBerg, 54,000.

Employment Contracts

Mr. Armstrong is employed as Chairman and Chief Executive Officer. The initial three-year term of Mr. Armstrong s employment agreement commenced on June 30, 2001, and is automatically extended for one year on June 30 of each year (such that the term is reset to three years) unless Mr. Armstrong receives notice from the chairman of the compensation committee that the board of directors has elected not to extend the agreement. Mr. Armstrong has agreed, during the term of the agreement and for five years thereafter, not to disclose (subject to typical exceptions, including, but not limited to, requirement of law or prior disclosure by a third party) any confidential information obtained by him while employed under the agreement. The agreement provided for a base salary of $330,000 per year, subject to annual review. In 2005, Mr. Armstrong s annual salary was increased to $375,000.

Mr. Pefanis is employed as President and Chief Operating Officer. The initial three-year term of Mr. Pefanis employment agreement commenced on June 30, 2001, and is automatically extended for one year on June 30 of each year (such that the term is reset to three years) unless Mr. Pefanis receives notice from the Chairman

Table of Contents

of the Board that the board of directors has elected not to extend the agreement. Mr. Pefanis has agreed, during the term of the agreement and for one year thereafter, not to disclose (subject to typical exceptions) any confidential information obtained by him while employed under the agreement. The agreement provided for a base salary of $235,000 per year, subject to annual review. In 2005, Mr. Pefanis annual salary was increased to $300,000.

See Compensation Discussion and Analysis for a discussion of how we use salary and bonus to achieve compensation objectives. See Potential Payments upon Termination or Change-In-Control for a discussion of the provisions in Messrs. Armstrong s and Pefanis employment agreements related to termination, change of control and related payment obligations.

Outstanding Equity Awards at Fiscal Year-End

The following table sets forth certain information with respect to outstanding equity awards at December 31, 2009 with respect to our Named Executive Officers:

	Option Awards					**Unit Awards**			
Name	**Number of Securities Underlying Unexercised Options (#) Exercisable**	**Number of Securities Underlying Unexercised Options (#) Unexercisable**	**Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)**	**Option Exercise Price ($)**	**Option Expiration Date**	**Number of Shares or Units of Stock That Have Not Vested (#)**	**Market Value of Shares or Units of Stock That Have Not Vested ($)(1)**	**Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(1)**
Greg L. Armstrong						120,000(2)	$ 6,342,000		
						60,000(3)	$ 3,171,000	120,000(3)	$ 6,342,000
						10,000(4)	$ 2,770,700	30,000(4)	$ 5,987,300
Harry N. Pefanis						80,000(2)	$ 4,228,000		
						40,000(3)	$ 2,114,000	80,000(3)	$ 4,228,000
						7,500(4)	$ 2,078,025	22,500(4)	$ 4,490,475
Al Swanson						17,000(2)	$ 898,450		
						11,000(3)	$ 581,350	22,000(3)	$ 1,162,700
								35,000(5)	$ 1,849,750
						2,500(4)	$ 692,675	7,500(4)	$ 1,496,825
W. David Duckett						39,175(2)	$ 2,070,399		
						25,000(3)	$ 1,321,250	50,000(3)	$ 2,642,500
						4,250	$ 1,177,548	12,750(4)	$ 2,544,602
John P. vonBerg						28,675(2)	$ 1,515,474		
						18,000(3)	$ 951,300	36,000(3)	$ 1,902,600
						3,500(4)	$ 969,745	10,500(4)	$ 2,095,555

(1) Market value of phantom units reported in these columns is calculated by multiplying the closing market price ($52.85) of our common units at December 31, 2009 (the last trading day of the fiscal year) by the number of units. No discount is applied for remaining performance threshold or service period requirements. The Class B units are valued based on the grant date fair value computed in accordance with FASB ASC Topic 718 assuming that the highest level of performance conditions will be met.

(2) All applicable performance (distribution) thresholds have been met, and these phantom units will vest upon the May 2010 distribution date. DERs associated with these phantom units have vested.

Table of Contents

(3) These phantom units will vest in one-third increments as follows: one-third will vest upon the May 2011 distribution date; one-third will vest upon the later of the May 2011 distribution date and the date on which we pay a quarterly distribution of at least $1.00; and one-third will vest upon the later of the May 2012 distribution date and the date on which we pay a quarterly distribution of at least $0.9375. The first 50% of DERs associated with these units is currently payable. The remaining 50% become payable in 25% increments upon achieving quarterly distribution levels of $0.95 and $1.00 per unit. Any phantom units that have not vested (and all associated DERs) as of the May 2014 distribution date will expire.

(4) Each Class B unit represents a profits interest in Plains AAP, L.P., which entitles the holder to participate in future profits and losses from operations, current distributions from operations, and an interest in future appreciation or depreciation in Plains AAP, L.P. s asset values, but does not represent an interest in the capital of Plains AAP, L.P. on the applicable grant date of the Class B units. As of December 31, 2009, 25% of the Class B units held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg had been earned. None of the Class B units have vested. For additional information regarding the Class B units, please read Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner Class B Units of Plains AAP, L.P.

(5) These phantom units will vest in one-third increments as follows: one-third will vest upon the later of the May 2011 distribution date and the date on which we pay a quarterly distribution of at least $0.9375, one-third will vest upon the later of the May 2012 distribution date and the date on which we pay a quarterly distribution of at least $1.00, and one-third will vest upon the later of the May 2013 distribution date and the date on which we pay a quarterly distribution of at least $1.0625. One-third of the DERs associated with these units is currently payable. The remaining two-thirds become payable in 50% increments upon achieving quarterly distribution levels of $0.9375 and $1.00 per unit. Any phantom units that have not vested (and all associated DERs) as of the May 2015 distribution date will expire.

Option Exercises and Units Vested

	Option Awards		Unit Awards	
Name	**Number of Units Acquired on Exercise (#)(1)**	**Value Realized on Exercise ($)**	**Number of Units Acquired on Vesting (#)(4)**	**Value Realized on Vesting ($)(4)**
Greg L. Armstrong	37,500	1,844,175(2)	90,000	3,710,700
Harry N. Pefanis	27,500	1,341,120(3)	60,000	2,473,800
Al Swanson			17,000	700,910
W. David Duckett			39,175	1,615,185
John P. vonBerg			28,675	1,182,270

(1) Represents the gross number and value of options exercised during the year ended December 31, 2009. The actual number of units delivered was net of the exercise price.

(2) The value realized upon exercise is based on the difference between the closing market price ($52.41) of our common units on December 23, 2009 (the exercise date) and the exercise price of the options ($3.232).

(3) The value realized upon exercise is based on the difference between the closing market price ($52.00) of our common units on December 22, 2009 (the exercise date) and the exercise price of the options ($3.232).

(4) Represents the gross number and value of phantom units that vested during the year ended December 31, 2009. The actual number of units delivered was net of income tax withholding. Consistent with the terms of our 2005 Long-Term Incentive Plan, the value realized upon vesting is computed by multiplying the closing market price ($41.23) of our common units on May 14, 2009 (the date preceding the vesting date) by the number of units that vested.

Table of Contents

Pension Benefits

We sponsor a 401(k) plan that is available to all U.S. employees, but we do not maintain a pension or defined benefit program.

Nonqualified Deferred Compensation and Other Nonqualified Deferred Compensation Plans

We do not have a nonqualified deferred compensation plan or program for our officers or employees.

Potential Payments upon Termination or Change-in-Control

The following table sets forth potential amounts payable to the Named Executive Officers upon termination of employment under various circumstances, and as if terminated on December 31, 2009.

	By Reason of Death ($)	By Reason of Disability ($)	By Company without Cause ($)	By Executive with Good Reason ($)	In Connection with a Change In Control ($)
Greg L. Armstrong					
Salary and Bonus	8,250,000(1)	8,250,000(1)	8,250,000(1)	8,250,000(1)	12,375,000(2)
Equity Compensation	12,684,000(3)	12,684,000(3)	15,855,000(4)	15,855,000(4)	15,855,000(5)
Health Benefits	N/A	32,102(6)	32,102(6)	32,102(6)	32,102(6)
Tax Gross-up	N/A	N/A	N/A	N/A	1,436,780(7)
Class B Units	N/A	N/A	N/A	N/A	5,382,400(8)
Total	20,934,000	20,966,102	24,137,102	24,137,102	35,081,282
Harry N. Pefanis					
Salary and Bonus	7,400,000(1)	7,400,000(1)	7,400,000(1)	7,400,000(1)	11,100,000(2)
Equity Compensation	8,456,000(3)	8,456,000(3)	10,570,000(4)	10,570,000(4)	10,570,000(5)
Health Benefits	N/A	38,632(6)	38,632(6)	38,632(6)	38,632(6)
Tax Gross-up	N/A	N/A	N/A	N/A	1,393,741(7)
Class B Units	N/A	N/A	N/A	N/A	4,036,800(8)
Total	15,856,000	15,894,632	18,008,632	18,008,632	27,139,173
Al Swanson (9)					
Equity Compensation	3,576,148(3)	3,576,148(3)	2,378,250(4)	N/A	5,390,700(5)
Class B Units	N/A	N/A	N/A	N/A	1,345,600(8)
Total	3,576,148	3,576,148	2,378,250	N/A	6,736,300
W. David Duckett (9)					
Equity Compensation	4,712,899(3)	4,712,899(3)	3,391,649(4)	N/A	6,034,149(5)
Class B Units	N/A	N/A	N/A	N/A	2,287,520(8)
Total	4,712,899	4,712,899	3,391,649	N/A	8,321,669
John P. vonBerg (9)					
Equity Compensation	3,418,074(3)	3,418,074(3)	2,466,774(4)	N/A	4,369,374(5)
Class B Units	N/A	N/A	N/A	N/A	1,883,840(8)

Total	3,418,074	3,418,074	2,466,774	N/A	6,253,214

(1) The employment agreements between Plains All American GP LLC and Messrs. Armstrong and Pefanis provide that if (i) their employment with Plains All American GP LLC is terminated as a result of their death, (ii) they terminate their employment with Plains All American GP LLC (a) because of a disability (as defined in Section 409A of the Code) or (b) for good reason (as defined below), or (iii) Plains All American GP LLC terminates their employment without cause (as defined below), they are entitled to a lump-sum amount equal to the product of (1) the sum of their (a) highest annual base salary paid prior to their date of termination and (b) highest annual bonus paid or payable for any of the three years prior to the date of termination, and (2) the lesser of (i) two or (ii) the number of days remaining in the term of their employment agreement divided by 360. The amount provided in the table assumes for each executive a termination date of December 31, 2009, and also assumes a highest annual base salary of $375,000 and highest annual bonus of $3,750,000 for Mr. Armstrong, and a highest annual base salary of $300,000 and highest annual bonus of $3,400,000 for Mr. Pefanis.

The employment agreements between Plains All American GP LLC and Messrs. Armstrong and Pefanis define cause as (i) willfully engaging in gross misconduct, or (ii) conviction of a felony involving moral turpitude. Notwithstanding, no act, or failure to act, on their part is willful unless done, or omitted to be done, not in good faith and without reasonable belief that such act or omission was in the best interest of Plains All American GP LLC or otherwise likely to result in no material injury to Plains All American GP LLC. However, neither Mr. Armstrong or Mr. Pefanis will be deemed to have been terminated for cause unless and until there is delivered to them a copy of a resolution of the board of directors of Plains All American GP LLC at a meeting held for that purpose (after reasonable notice and an opportunity to be heard), finding that Mr. Armstrong or Mr. Pefanis, as applicable, was guilty of the conduct described above, and specifying the basis for that finding. If Mr. Armstrong or Mr. Pefanis were terminated for cause, Plains All American GP LLC would be obligated to pay base salary through the date of termination, with no other payment obligations triggered by the termination under the employment agreement or other employment arrangement.

The employment agreements between Plains All American GP LLC and Messrs. Armstrong and Pefanis define good reason as the occurrence of any of the following circumstances: (i) removal by Plains All American GP LLC from, or failure to re-elect them to, the positions to which Messrs. Armstrong and Pefanis were appointed pursuant to their respective employment agreements, except in connection with their termination for cause (as defined above); (ii) (a) a reduction in their rate of base salary (other than in connection with across-the-board salary reductions for all executive officers of Plains All American GP LLC, unless such reduction reduces their base salary to less than 85% of their current base salary, (b) a material reduction in their fringe benefits, or (c) any other material failure by Plains All American GP LLC to comply with its obligations under their employment agreements to pay their annual salary and bonus, reimburse their business expenses, provide for their participation in certain employee benefit plans and arrangements, furnish them with suitable office space and support staff, or allow them no less than 15 business days of paid vacation annually; or (iii) the failure of Plains All American GP LLC to obtain the express assumption of the employment agreements by a successor entity (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of Plains All American GP LLC.

(2) Pursuant to their employment agreements, if Messrs. Armstrong and Pefanis terminate their employment with Plains All American GP LLC within three (3) months of a change in control (as defined below), they are entitled to a lump-sum payment in an amount equal to the product of (i) three and (ii) the sum of (a) their highest annual base salary previously paid to them and (b) their highest annual bonus paid or payable for any of the three years prior to the date of such termination. The amount provided in the table assumes a change in control and termination date of December 31, 2009, and also assumes a highest annual base salary of $375,000 and highest annual bonus of $3,750,000 for Mr. Armstrong, and a highest annual base salary of $300,000 and highest annual bonus of $3,400,000 for Mr. Pefanis.

For this purpose a change in control is currently defined in their employment agreements to mean (i) the acquisition by a person or group (other than Vulcan Energy or a wholly owned subsidiary thereof) of beneficial ownership, directly or indirectly, of 50% or more of the membership interest of Plains All American GP LLC or (ii) the owners of the membership interests of Plains All American GP LLC on June 30, 2001 ceasing to beneficially own, directly or indirectly, more than 50% of the membership interests of Plains All American GP LLC.

In August 2005, Vulcan Energy increased its interest in Plains All American GP LLC from approximately 44% to greater than 50%. The consummation of the transaction constituted a change of control under the employment agreements with Messrs. Armstrong and Pefanis. However, Messrs. Armstrong and Pefanis entered into agreements with Plains All American GP LLC waiving their rights to payments under their employment agreements in connection with the change of control, contingent on the execution and performance by Vulcan Energy of a voting agreement with Plains All American GP LLC that restricts certain of Vulcan s voting rights. Upon a breach, termination, or notice of termination of the voting agreement by Vulcan Energy these waivers will automatically terminate and a change of control would be deemed to have occurred.

Table of Contents

(3) The letters evidencing phantom unit grants to our Named Executive Officers between 2005 and 2009 provide that in the event of their death or disability (as defined below), all of their then outstanding phantom units and associated DERs will be deemed nonforfeitable, and (i) any unvested phantom units that had satisfied all of the vesting criteria as of the date of their termination but for the passage of time would vest on the next following distribution date and (ii) the remaining unvested outstanding phantom units will vest on the distribution date on which the vesting criteria is met. For this purpose disability means a physical or mental infirmity that impairs the ability substantially to perform duties for a period of eighteen (18) months or that the general partner otherwise determines constitutes a disability.

The dollar value amount provided assumes the death or disability occurred on December 31, 2009. As a result, all phantom units and the associated DERs of our Named Executive Officers would have become nonforfeitable effective as of December 31, 2009, and vested on February 12, 2010 to the extent the vesting criteria had been satisfied (other than the passage of time) or, if the vesting criteria had not been satisfied, at the time(s) described in the footnotes to the Outstanding Equity Awards at Fiscal Year-End table. For the 2007 and 2009 grants, any units not vested by May 2014 and May 2015, respectively, would expire. The dollar value given assumes that all performance thresholds will be timely achieved if deemed probable of occurrence as of December 31, 2009, and is based on the market value on December 31, 2009 ($52.85 per unit) without discount for service period. If the performance thresholds were not deemed probable of occurrence as of December 31, 2009, the units are assumed to expire unvested in May 2014. At December 31, 2009, an annualized distribution level of $3.90 was deemed probable of occurrence. All outstanding 2005 and 2006 grants, two-thirds of the 2007 grants and one-third of the 2009 grants were assumed to eventually vest as a result.

(4) Pursuant to the phantom unit grants to our Named Executive Officers between 2005 and 2009, in the event their employment is terminated other than in connection with a change in control (as defined in Footnote 5 below) or by reason of death, disability (as defined in Footnote 3 above) or retirement, all of the phantom units and associated DERs (regardless of vesting) then outstanding under such phantom unit grants would automatically be forfeited as of the date of termination; provided, however, that if Plains All American GP LLC terminated their employment other than for cause (as defined below), any unvested phantom units that had satisfied all of the vesting criteria as of the date of their termination but for the passage of time would be deemed nonforfeitable and would vest on the next following distribution date. The dollar value amount provided assumes that our Named Executive Officers were terminated without cause on December 31, 2009. As a result, all of the outstanding 2005 and 2006 phantom unit grants and one-third of the 2007 phantom unit grants held by our Named Executive Officers would be deemed nonforfeitable and would vest on the February 2010 distribution date. The remaining two-thirds of the outstanding 2007 phantom unit grants and all of the 2009 phantom unit grants would be forfeited. The dollar value given is based on the market value on December 31, 2009 of $52.85 per unit, without discount for service period. In addition to the foregoing, under Canadian law, Mr. Duckett could have a claim for additional payment if inadequate notice were given for a termination without cause.

Under the waiver signed in 2005 by Mr. Armstrong and Mr. Pefanis (see footnote 2 above), upon a termination of employment by the company without cause or by the executive for good reason (in each case as defined in the relevant employment agreement) all of the executive s outstanding awards under the 1998 and 2005 Long-Term Incentive Plans would immediately vest.

(5) The letters evidencing the phantom unit grants to our Named Executive Officers between 2005 and 2009 provide that in the event of a change of status (as defined below), all of the then outstanding phantom units and associated DERs will be deemed nonforfeitable, and such phantom units will vest in full (i.e., the phantom units will become payable in the form of one common unit per phantom unit) upon the next following distribution date. Assuming the change in status occurred on December 31, 2009, all outstanding phantom units and the associated DERs would have become nonforfeitable as of December 31, 2009, and such phantom units would vest on the February 2010 distribution date.

The phrase change in status means, with respect to a Named Executive Officer, the occurrence, during the period beginning two and a half months prior to and ending one year following a change of control (as defined below), of any of the following: (A) the termination of employment by Plains All American GP LLC other than a termination for cause (as defined below), or (B) the termination of employment by the Named Executive Officer due to the occurrence, without the Named Executive Officer s written consent, of (i) any material diminution in the Named Executive Officer s authority, duties or responsibilities, (ii) any material reduction in the Named Executive Officer s base salary or (iii) any other action or inaction that would constitute a material breach of the agreement by Plains All American GP LLC.

The phrase change of control means, and is deemed to have occurred upon the occurrence of, one or more of the following events: (i) Plains All American GP LLC ceasing to be the general partner of our general partner; (ii) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all of the assets of our partnership or Plains All American GP LLC to any person and/or its affiliates, other than to us or Plains All American GP LLC, including any employee benefit plan thereof; (iii) the consolidation, reorganization, merger, or any other similar transaction involving (A) a person other than us or Plains All American GP LLC and (B) us, Plains All American GP LLC or both; (iv) the persons who own membership interests in Plains All American GP LLC as of the grant date ceasing to beneficially own, directly or indirectly, more than 50% of the membership interests of Plains All American GP LLC; or (v) any person, including any partnership, limited partnership, syndicate or other group deemed a person for purposes of Section 13(d) or 14(d) of the Securities Exchange Act of 1934, as amended, becoming the beneficial owner, directly or indirectly, of more than 49.9% of the membership interest in Plains All American GP LLC. With respect to the lattermost event, the 2005 grant letter makes an exception for any existing member of Plains All American GP LLC if the member signs a voting agreement such as that executed by Vulcan Energy in August 2005 (such exception not applying to the November 2005 grants to Messrs. Duckett and vonBerg or the February 2006 grant to Mr. Swanson). Notwithstanding the definition of change of control, no change of control is deemed to have occurred in connection with a restructuring or reorganization related to the securitization and sale to the public of direct or indirect equity interests in the general partner if (x) Plains All American GP LLC retains direct or indirect control over the general partner and (y) the current members of Plains All American GP LLC continue to own more than 50% of the member interest in Plains All American GP LLC.

The term cause means (i) the failure to perform a job function in accordance with standards described in writing, or (ii) the violation of Plains All American GP LLC s Code of Business Conduct (unless waived in accordance with the terms thereof), in each case, with the specific failure or violation described in writing.

(6) Pursuant to their employment agreements with Plains All American GP LLC, if Messrs. Armstrong or Pefanis are terminated other than (i) for cause (as defined in Footnote 1 above), (ii) by reason of death or (iii) by resignation (unless such resignation is due to a disability or for good reason (each as defined in Footnote 1, above)), then they are entitled to continue to participate, for a period which is the lesser of two years from the date of termination or the remaining term of the employment agreement, in such health and accident plans or arrangements as is made available by Plains All American GP LLC to its executive officers generally. The amounts provided in the table assume a termination date of December 31, 2009.

(7) Pursuant to their employment agreements, Messrs. Armstrong and Pefanis will be reimbursed for any excise tax due under Section 4999 of the Code as a result of compensation (parachute) payments made under their respective employment agreements. The range of values of this benefit assumes that Messrs. Armstrong and Pefanis were terminated in connection with a change in control effective as of December 31, 2009.

(8) Pursuant to the Class B Restricted Units Agreements, upon the occurrence of a Change in Control, any earned Class B units become vested units and, to the extent any Class B units remain unearned, an incremental 25% of the number of Class B units originally granted becomes vested. As of December 31, 2009, 25% of the Class B units held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg had been earned. Assuming a Change in Control on December 31, 2009, 50% of the Class B units held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg would become vested. The value of such Class B units as reflected in the table is derived in accordance with FASB ASC Topic 718. Change in Control means the determination by the Board that one of the following events has occurred: (i) Plains All American GP LLC ceases to retain direct or indirect control over the Partnership; (ii) the owners of Plains All American GP LLC as of

August 29, 2007 (the Grant Date) and their affiliates (the Owner

Table of Contents

Affiliates) cease to own directly or indirectly at least 50% of its member interest; (iii) a person or group (as such terms are used in Sections 13(d) and 14(d) of the Exchange Act) becomes after the Grant Date the beneficial owner (as defined in Rules 13(d)-3 and 13(d)-5 under the Exchange Act), directly or indirectly, of more than 50% of the member interest of Plains All American GP LLC; or (iv) a transfer, sale, exchange or other disposition in a single transaction or series of transactions (whether by merger or otherwise) of all or substantially all of the assets of the Plains AAP, L.P. or the Partnership to one or more persons who are not Affiliates of Plains AAP, L.P., other than a transaction in which the Owner Affiliates become the beneficial owners, directly or indirectly, of more than 50% of the voting power of such person or persons immediately following such transaction.

(9) If Messrs. Swanson, Duckett or vonBerg were terminated for cause, Plains All American GP LLC would be obligated to pay base salary through the date of termination, with no other payment obligation triggered by the termination under any employment arrangement.

Confidentiality, Non-Compete and Non-Solicitation Arrangements

Pursuant to his employment agreement, Mr. Armstrong has agreed to maintain the confidentiality of PAA information for a period of five years after the termination of his employment. Mr. Pefanis has agreed to a similar restriction for a period of one year following the termination of his employment. Mr. Duckett has agreed to maintain confidentiality following termination of his employment for a period of two years with respect to customer lists. He has also agreed not to compete in a specified geographic area for a period of two years after termination of his employment. Mr. vonBerg has agreed to maintain confidentiality and not to solicit customers for a period of one year following termination of his employment.

Compensation of Directors

The following table sets forth a summary of the compensation paid to Plains All American GP LLC s non-employee directors in 2009:

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($) (1)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings	All Other Compensation ($)	Total ($)
W. Lance Conn (2)	22,500	178,984					201,484
Everardo Goyanes	75,000	91,969					166,969
Gary R. Petersen (3)	45,000	n/a					45,000
Robert V. Sinnott	47,000	45,985					92,985
Arthur L. Smith	62,000	91,969					153,969
J. Taft Symonds	60,000	91,969					151,969
Christopher M. Temple (2)	22,500	n/a					22,500

(1) In connection with the August 2009 vesting of director LTIP awards, Messrs. Goyanes, Smith and Symonds each were granted 2,500 units, Mr. Sinnott was granted 1,250 units and Mr. Conn was granted 313 units by virtue of the automatic re-grant feature of the vested awards. Upon vesting of the director LTIP awards in August 2009 (other than the incremental audit committee awards), a cash payment was made to Vulcan Capital and an affiliate of EnCap as directed by Messrs. Temple and Petersen, respectively. Such cash payment was based on the unit value of Mr. Sinnott s award on the previous year s vesting date. In addition to the automatic re-grant in August, Mr. Conn also received an initial grant of 5,000 LTIPs in May 2009. The dollar value of LTIPs granted during 2009 is based on the grant date fair value computed in accordance with FASB ASC Topic 718.

(2) Compensation attributable to the director designated by Vulcan is assigned to Vulcan. Mr. Conn served as Vulcan s designated director from November 2008 until May 2009, and Mr. Temple served as Vulcan s designated director from May 2009 until February 2010. In February 2010, Mr. Conn resigned from the

Table of Contents

board and Mr. McKay replaced Mr. Temple as Vulcan s designated director. Mr. Temple continues to serve as a director in an at-large capacity.

(3) Mr. Petersen assigns to EnCap Energy Capital Fund III, L.P. any compensation attributable to his service as director.

Each director of Plains All American GP LLC who is not an employee of Plains All American GP LLC is reimbursed for any travel, lodging and other out-of-pocket expenses related to meeting attendance or otherwise related to service on the board (including, without limitation, reimbursement for continuing education expenses). Each non-employee director is currently paid an annual retainer fee of $45,000. Mr. Armstrong is otherwise compensated for his services as an employee and therefore receives no separate compensation for his services as a director. In addition to the annual retainer, each committee chairman (other than the chairman of the audit committee) receives $2,000 annually. The chairman of the audit committee receives $30,000 annually, and the other members of the audit committee receive $15,000 annually, in each case, in addition to the annual retainer. During 2009, Messrs. Sinnott, Goyanes and Smith served as chairmen of the compensation, audit and governance committees, respectively.

Our non-employee directors receive LTIP awards or cash equivalent awards as part of their compensation. The LTIP awards vest annually in 25% increments over a four-year period and have an automatic re-grant feature such that as they vest, an equivalent amount is granted. The three non-employee directors who serve on the audit committee each have outstanding a grant of 10,000 units (vesting 2,500 units per year). Messrs. Temple and Sinnott each have outstanding a grant of 5,000 units (vesting 1,250 per year). Upon vesting of the director LTIPs (other than the incremental audit committee awards), a cash payment is made to Vulcan Capital as directed by the Vulcan designee and to an affiliate of EnCap as directed by Mr. Petersen. Such cash payment is based on the unit value of Mr. Sinnott s award on the previous year s vesting date.

All LTIP awards held by a director vest in full upon the next following vesting date after the death or disability (as determined in good faith by the board) of the director. For audit committee grants, the awards also vest in full if such director (i) retires (no longer with full-time employment and no longer serving as an officer or director of any public company) or (ii) is removed from the board of directors or is not reelected to the board of directors, unless such removal or failure to reelect is for good cause, as defined in the letter granting the units.

Reimbursement of Expenses of Our General Partner and its Affiliates

We do not pay our general partner a management fee, but we do reimburse our general partner for all direct and indirect costs of services provided to us, incurred on our behalf, including the costs of employee, officer and director compensation (other than expenses related to the Class B units of Plains AAP, L.P.) and benefits allocable to us, as well as all other expenses necessary or appropriate to the conduct of our business, allocable to us. We record these costs on the accrual basis in the period in which our general partner incurs them. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion.

Table of Contents

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

Beneficial Ownership of Limited Partner Interest

Our common units outstanding represent 98% of our equity (limited partner interest). The 2% general partner interest is discussed separately below under Beneficial Ownership of General Partner Interest. The following table sets forth the beneficial ownership of limited partner units held by beneficial owners of 5% or more of the units, directors, the Named Executive Officers, and all directors and executive officers as a group as of February 22, 2010.

Name of Beneficial Owner	Common Units	Percentage of Common Units
Paul G. Allen	16,293,379(1)	12.0%(2)
Vulcan Energy Corporation	12,390,120(3)	9.1%
Richard Kayne/Kayne Anderson Capital Advisors, L.P.	7,281,859(4)	5.3%
Greg L. Armstrong	347,490(5)(6)	(7)
Harry N. Pefanis	221,118(6)	(7)
Dave Duckett	142,497(6)	(7)
John P. vonBerg	28,803(6)	(7)
Al Swanson	15,803(6)	(7)
Everardo Goyanes	26,700	(7)
Geoff McKay	(8)	(7)
Gary R. Petersen	5,200	(7)
Robert V. Sinnott	53,302(9)	(7)
Arthur L. Smith	20,850	(7)
J. Taft Symonds	32,300	(7)
Chris Temple		
All directors and executive officers as a group (16 persons)	1,084,488(10)	(7)

(1) Mr. Allen owns approximately 80% of the outstanding shares of common stock of Vulcan Energy Corporation. Mr. Allen also controls Vulcan Capital Private Equity I LLC (Vulcan I LLC), which is the record holder of 3,706,044 common units, and Vulcan Capital Private Equity II LLC (together with Vulcan I LLC, Vulcan LLC), which is the record holder of 197,215 common units. The address for Mr. Allen and Vulcan LLC is 505 Fifth Avenue S, Suite 900, Seattle, Washington 98104. Mr. Allen disclaims any deemed beneficial ownership, beyond his pecuniary interest, in any of our partner interests held by Vulcan Energy Corporation or any of its affiliates.

(2) Giving effect to the indirect ownership by Vulcan Energy Corporation of a portion of our general partner, Mr. Allen may be deemed to beneficially own approximately 12.7% of our total equity. Mr. Allen disclaims any deemed beneficial ownership, beyond his pecuniary interest, in any of our partner interests held by Vulcan Energy Corporation or any of its affiliates.

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

(4) Richard A. Kayne is Chief Executive Officer and Director of Kayne Anderson Investment Management, Inc., which is the general partner of Kayne Anderson Capital Advisors, L.P. (KACALP). Various accounts (including KAFU Holdings, L.P., which owns a portion of our general partner) under the management or control of KACALP own 7,016,623 common units. Mr. Kayne may be deemed to beneficially own such units. In addition, Mr. Kayne directly owns or has sole voting and dispositive power over 265,236 common units. Mr. Kayne disclaims beneficial ownership of any of our partner interests other than units held by him or interests attributable to him by virtue of his interests in the accounts that own our partner interests. The address for Mr. Kayne and Kayne Anderson Investment Management, Inc. is 1800 Avenue of the Stars, 2nd Floor, Los Angeles, California 90067.

(5) Does not include approximately 14,923 common units owned by our general partner in connection with its Performance Option Plan. Mr. Armstrong disclaims any beneficial ownership of such units beyond his rights as a grantee under the plan. See Item 13. Certain Relationships and Related Transactions, and Director Independence General Partner s Performance Option Plan.

(6) Does not include unvested phantom units granted under our Long-Term Incentive Plans, none of which will vest within 60 days of the date hereof. See Item 11. Executive Compensation Outstanding Equity Awards at Fiscal Year-End.

(7) Less than one percent.

(8) The GP LLC Agreement specifies that certain of the owners of our general partner have the right to designate a member of our board of directors. Mr. McKay has been designated as one of our directors by Vulcan Energy Corporation, of which he is Chairman of the Board. Mr. McKay may receive performance-based compensation based on the performance of the holdings of Vulcan Energy Corporation and Vulcan LLC, including the common units held by these entities. Mr. McKay disclaims any deemed beneficial ownership of our common units held by Vulcan Energy Corporation and Vulcan LLC or any of their affiliates beyond his pecuniary interest therein, if any. By virtue of its greater than 50% ownership in the general partner, Vulcan Energy Corporation controls the at-large seats occupied by Mr. Petersen and Mr. Temple.

(9) Pursuant to the GP LLC Agreement, Mr. Sinnott has been designated as one of our directors by KAFU Holdings, L.P., which is controlled by Kayne Anderson Investment Management, Inc., of which he is President. Mr. Sinnott disclaims any deemed beneficial ownership of the interests owned by KAFU Holdings, L.P. or its affiliates, beyond his pecuniary interest therein, if any. Mr. Sinnott has a non-controlling ownership interest in KACALP, which is the general partner of KAFU Holdings, L.P. KACALP is entitled to a percentage of the profits earned by the funds invested in KAFU Holdings, L.P. The address for KAFU Holdings, L.P. is 1800 Avenue of the Stars, 2nd Floor, Los Angeles, California 90067.

(10) As of February 19, 2010, no units were pledged by directors or Named Executive Officers. Certain of the directors and Named Executive Officers hold units in marginable broker s accounts, but none of the units were margined as of February 19, 2010.

Table of Contents

Beneficial Ownership of General Partner Interest

Plains AAP, L.P. owns all of our incentive distribution rights and, through its 100% member interest in PAA GP LLC, our 2% general partner interest. The following table sets forth the effective ownership of Plains AAP, L.P. (after giving effect to proportionate ownership of Plains All American GP LLC, its 1% general partner).

Name of Owner and Address (in the case of Owners of more than 5%)	Percentage Ownership of Plains AAP, L.P. (1)
Paul G. Allen (2) 505 Fifth Avenue S, Suite 900 Seattle, WA 98104	50.1%
Vulcan Energy Corporation (3) c/o Plains All American GP LLC 333 Clay Street, Suite 1600 Houston, TX 77002	50.1%
Oxy Holding Company (Pipeline), Inc. (4) 10889 Wilshire Boulevard Los Angeles, CA 90024	21.9%
KAFU Holdings, L.P. (5) 1800 Avenue of the Stars, 2nd Floor Los Angeles, CA 90067	17.9%
PAA Management, L.P. (6)	4.6%
Strome Group, L.P.	2.6%
Strome MLP Fund, L.P.	0.9%
Lynx Holdings I, LLC	1.4%
Various Individual Investors	0.6%

(1) Plains AAP, L.P. owns a 100% member interest in PAA GP LLC, which owns our 2% general partner interest. Plains AAP, L.P. has pledged its member interest, as well as its interest in our incentive distribution rights, as security for its obligations under the Credit Agreement dated as of January 3, 2008 among Plains AAP, L.P., Citibank, N.A. and the lenders party thereto (the Plains AAP Credit Agreement). A default by Plains AAP, L.P. under the Plains AAP Credit Agreement could result in a change in control of our general partner. Certain members of management own a profits interest in Plains AAP, L.P. in the form of Class B units.

(2) Mr. Allen owns approximately 80% of the outstanding shares of common stock of Vulcan Energy Corporation. Vulcan Energy GP Holdings Inc., a subsidiary of Vulcan Energy Corporation, owns 50.1% of the equity of our general partner. Vulcan Energy Corporation has pledged all of its equity interest in Vulcan Energy GP Holdings Inc. as security for its obligations under the Second Amended and Restated Credit Agreement dated as of August 12, 2005 among Vulcan Energy Corporation, Bank of America, N.A. and the lenders party thereto (as amended, the VEC Credit Agreement). A default by Vulcan Energy Corporation under the VEC Credit Agreement could result in an indirect change in control of our general partner. Mr. Allen disclaims any deemed beneficial ownership, beyond his pecuniary interest, in any of our partner interests held by Vulcan Energy Corporation or any of its affiliates.

(3) Mr. McKay disclaims any deemed beneficial ownership of the interests held by Vulcan Energy Corporation and its affiliates beyond his pecuniary interest therein, if any. In August 2005, Vulcan Energy Corporation entered into a voting agreement pursuant to which it agreed to restrict certain of its voting rights to help preserve a balanced board. See Item 10. Directors and Executive Officers of Our General Partner and Corporate Governance Partnership Management and Governance for more information regarding this agreement.

Table of Contents

(4) Oxy has the right to designate an individual to attend Board meetings in an observer capacity. Under certain circumstances involving changes in senior-most management, Oxy will have the right to designate a director to serve on the Board and the authorized number of Board members will be expanded to a total of nine.

(5) Mr. Sinnott disclaims any deemed beneficial ownership of the interests owned by KAFU Holdings, L.P. beyond his pecuniary interest therein, if any. Mr. Sinnott has a non-controlling ownership interest in KACALP, which is the general partner of KAFU Holdings, L.P. KACALP is entitled to a percentage of the profits earned by the funds invested in KAFU Holdings, L.P.

(6) PAA Management, L.P. is owned entirely by certain current and former members of senior management, including Messrs. Armstrong (approximately 25%), Pefanis (approximately 14%), Duckett (approximately 4%), vonBerg (approximately 4%) and Swanson (approximately 5%). Other than Mr. Armstrong, no directors own any interest in PAA Management, L.P. Executive officers as a group own approximately 66% of PAA Management, L.P. Mr. Armstrong disclaims any beneficial ownership of the general partner interest owned by Plains AAP, L.P., other than through his ownership interest in PAA Management, L.P.

Equity Compensation Plan Information

The following table sets forth certain information with respect to our equity compensation plans as of December 31, 2009. For a description of these plans, see Item 13. Certain Relationships and Related Transactions, and Director Independence Equity-Based Long-Term Incentive Plans.

Plan Category	**Number of Units to be Issued upon Exercise/Vesting of Outstanding Options, Warrants and Rights (a)**	**Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)**	**Number of Units Remaining Available for Future Issuance under Equity Compensation Plans (c)**
Equity compensation plans approved by unitholders:			
1998 Long Term Incentive Plan	672,400(1)	N/A(2)	235,327(1)(3)
2005 Long Term Incentive Plan	1,127,420(4)	N/A(2)	1,285,247(3)
Equity compensation plans not approved by unitholders:			
1998 Long Term Incentive Plan	(1)(5)	N/A(2)	(6)
General Partner s Performance Option Plan	(7)	$ 3.232(8)	(7)
PPX Successor LTIP	299,000(9)	N/A(2)	700,809(9)

(1) As originally instituted by our former general partner prior to our initial public offering, the 1998 LTIP contemplated the issuance of up to 975,000 common units to satisfy awards of phantom units. Upon vesting, these awards could be satisfied either by (i) primary issuance of units by us or (ii) cash settlement or purchase of units by our general partner with the cost reimbursed by us. In 2000, the 1998 LTIP was amended, as provided in the plan, without unitholder approval to increase the maximum awards to 1,425,000 phantom units; however, we can issue no more than 975,000 new units to satisfy the awards. Any additional units must be purchased by our general partner in the open market or in private transactions and be reimbursed by us. As of December 31, 2009, we have issued approximately 427,742 common units in satisfaction of vesting under the 1998 LTIP. The number of units presented in column (a) assumes that all remaining grants will be satisfied by the issuance of new units upon vesting. In fact, a substantial number of phantom units that have vested were satisfied without the issuance of units. These phantom units were settled in cash or withheld for taxes. Any units not issued upon vesting will become available for future

issuance under column (c).

Table of Contents

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

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

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

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

(6) Awards for up to 360,469 phantom units may be granted under the portion of the 1998 LTIP not approved by unitholders; however, no common units are available for future issuance under the plan, because all such awards must be satisfied with cash or out of units purchased by our general partner and reimbursed by us.

(7) Our general partner has adopted a Performance Option Plan for officers and key employees pursuant to which optionees have the right to purchase units from the general partner. The 450,000 units that were originally authorized to be sold under the plan were contributed to the general partner by certain of its owners in connection with the transfer of a majority of our general partner interest in 2001 without economic cost to the Partnership. Thus, there will be no units issued upon exercise/vesting of outstanding options. Options for 5,000 units were outstanding at December 31, 2009. All are vested, and no units remain available for future grant. See Item 13. Certain Relationships and Related Transactions, and Director Independence General Partner s Performance Option Plan.

(8) As of December 31, 2009, the strike price for all outstanding options under the general partner s Performance Option Plan was approximately $3.232 per unit. The strike price decreases as distributions are paid. See Item 13. Certain Relationships and Related Transactions, and Director Independence General Partner s Performance Option Plan.

(9) In connection with the Pacific merger, under applicable stock exchange rules, we carried over the available units under the Pacific LTIP (applying the conversion ratio of 0.77 PAA units for each Pacific unit). In that regard, we have adopted the Plains All American PPX Successor Long-Term Incentive Plan (the PPX Successor LTIP). Potential awards under such plan include options and phantom units (with or without tandem DERs). The provisions of such plan are substantially the same as the 2005 LTIP, except that awards under the PPX Successor LTIP may only be made to employees who were working for Pacific at the time of the merger or to employees hired after the date of the Pacific acquisition.

Table of Contents

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

For a discussion of director independence, see Item 10. Directors and Executive Officers of Our General Partner and Corporate Governance.

Our General Partner

Our operations and activities are managed, and our officers and personnel are employed, by our general partner (or, in the case of our Canadian operations, PMC (Nova Scotia) Company). We do not pay our general partner a management fee, but we do reimburse our general partner for all expenses incurred on our behalf (other than expenses related to the Class B units of Plains AAP, L.P.). Total costs reimbursed by us to our general partner for the year ended December 31, 2009 were approximately $328 million.

Our general partner owns the 2% general partner interest and all of the incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 ($1.80 annualized) per unit, 25% of the amounts we distribute in excess of $0.495 ($1.98 annualized) per unit and 50% of amounts we distribute in excess of $0.675 ($2.70 annualized) per unit. In connection with the Pacific, Rainbow and PNGS acquisitions, our general partner agreed to a temporary reduction in the amount of incentive distributions otherwise payable to it. Following our distribution in February 2010, the remaining incentive distribution reductions related to the Pacific, Rainbow and PNGS acquisitions totaled approximately $18 million.

The following table illustrates the allocation of aggregate distributions at different per-unit levels, excluding the effect of the incentive distribution reductions:

Annual LP Distribution Per Unit	Distribution to LP Unitholders(1)(2)	Distribution to GP(1)(2)(3)	Total Distribution(2)	GP % of Total Distribution
$1.80	$ 245,045	$ 5,001	$ 250,046	2%
$1.98	$ 269,549	$ 9,325	$ 278,874	3%
$2.70	$ 367,567	$ 41,998	$ 409,565	10%
$3.70	$ 503,703	$ 178,134	$ 681,837	26%
$3.80	$ 517,317	$ 191,747	$ 709,064	27%
$3.90	$ 530,930	$ 205,361	$ 736,291	28%
$4.00	$ 544,544	$ 218,975	$ 763,519	29%

(1) In thousands.

(2) Assumes 136,136,000 units outstanding. The actual number of units outstanding as of December 31, 2009 was 136,135,988. An increase in the number of units outstanding would increase both the distribution to unitholders and the distribution to the

general partner for any given level of distribution per unit.

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

Equity-Based Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the 1998 LTIP) and the Plains All American GP LLC 2005 Long-Term Incentive Plan (the 2005 LTIP) for employees and directors of our general partner and its affiliates who perform services for us, and the PPX Successor LTIP for former Pacific employees and employees hired after the date of the Pacific merger (together with the 1998 LTIP and 2005 LTIP, the Plans). Awards contemplated by the Plans include phantom units (referred to as restricted units in the 1998 LTIP), distribution equivalent rights (DERs) and unit options. As amended, the 1998 LTIP authorizes the grant of awards covering an aggregate of 1,425,000 common units deliverable upon vesting or exercise (as applicable) of such awards. The 2005 LTIP authorizes the grant of awards covering an aggregate of 3,000,000 common units deliverable upon vesting or exercise (as applicable) of such awards. The PPX Successor LTIP authorizes the grant of awards covering an aggregate of 999,809 common units deliverable upon vesting or

Table of Contents

exercise (as applicable) of such awards. Our general partner s board of directors has the right to alter or amend the Plans from time to time, including, subject to any applicable NYSE listing requirements, increasing the number of common units with respect to which awards may be granted; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of such participant.

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

Phantom Units. A phantom unit entitles the grantee to receive, upon the vesting of the phantom unit, a common unit (or cash equivalent, depending on the terms of the grant).

As of December 31, 2009, grants of approximately 672,400, 1,127,420 and 713,100 unvested phantom units were outstanding under the 1998 LTIP, 2005 LTIP and PPX Successor LTIP, respectively, and approximately 235,327, 1,285,247 and 700,809 remained available for future grant, respectively. The compensation committee or board of directors may, in the future, make additional grants under the Plans to employees and directors containing such terms as the compensation committee or board of directors shall determine, including DERs with respect to phantom units. DERs entitle the grantee to a cash payment, either while the award is outstanding or upon vesting, equal to any cash distributions paid on a unit while the award is outstanding.

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

Unit Options. Although the Plans currently permit the grant of options covering common units, no options have been granted under the Plans to date. However, the compensation committee or board of directors may, in the future, make grants under the plan to employees and directors containing such terms as the compensation committee or board of directors shall determine, provided that unit options have an exercise price equal to the fair market value of the units on the date of grant.

General Partner s Performance Option Plan

In 2001, certain owners of the general partner contributed an aggregate of 450,000 subordinated units (now converted into common units) to the general partner to provide a pool of units available for the grant of options to management and key employees. In that regard, the general partner adopted the Plains All American 2001 Performance Option Plan. Because the awards are for services provided to the general partner, the expense associated with the awards is recorded on the general partner s financial statements. As of December 31, 2009, 5,000 options remained outstanding under the plan, all of which are fully vested. No units remain available for future grant. The original exercise price of the options was $22 per unit, declining over time by an amount equal to 80% of each quarterly distribution per unit. As of December 31, 2009, the exercise price was approximately $3.232 per unit. Because the units underlying the plan were contributed to the general partner, we have no obligation to reimburse the general partner for the cost of the units upon exercise of the options.

Class B Units of Plains AAP, L.P.

In August 2007, the owners of Plains AAP, L.P. authorized the creation and issuance of up to 200,000 Class B units of Plains AAP, L.P. and authorized the compensation committee of Plains All American GP LLC to issue grants of Class B units to create long-term incentives for our management. The entire economic burden of the Class B units, which are equity classified, is borne solely by Plains AAP, L.P. and does not impact our cash or units outstanding. Therefore, we recognize the grant date fair value of the Class B units as compensation expense over the service period. The expense is also reflected as a capital contribution, and thus results in a corresponding credit to Partners Capital in our Consolidated Financial Statements. The expense and capital contribution for the twelve months ended December 31, 2009 was approximately $5 million. We will not be obligated to reimburse Plains AAP, L.P. for such costs and any distributions made on the Class B units will not reduce the amount of cash

Table of Contents

available for distribution to our unitholders. Each Class B unit represents a profits interest in Plains AAP, L.P., which entitles the holder to participate in future profits and losses from operations, current distributions from operations, and an interest in future appreciation or depreciation in Plains AAP, L.P. s asset values. As of December 31, 2009, 165,500 Class B units were issued and outstanding.

The outstanding Class B units are subject to restrictions on transfer and generally become earned (entitled to participate in distributions) in percentage increments when the annualized quarterly distributions on our common units equal or exceed certain thresholds. Class B units granted prior to 2009 become earned in 25% increments when the annualized quarterly distributions on our common units equal or exceed $3.50, $3.75, $4.00 and $4.50 per unit. Class B units granted in 2009 become earned in increments of 37.5%, 37.5% and 25% 180 days after we pay annualized quarterly distributions on our common units of $3.75, $4.00 and $4.50, respectively. Upon achievement of these performance thresholds (or, in some cases, within six months thereafter), the Class B units will be entitled to their proportionate share of all quarterly cash distributions made by Plains AAP, L.P. in excess of $11 million per quarter (as adjusted for debt service costs and excluding special distributions funded by debt). Assuming all authorized Class B units are issued, the maximum participation would be 8% of the amount in excess of $11 million per quarter, as adjusted. As of December 31, 2009, approximately 25% of the outstanding Class B units granted prior to 2009 had been earned and none of the Class B units granted in 2009 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 for any reason prior to January 1, 2016, other than a termination of employment by the employee for good reason or by Plains All American GP LLC other than for cause (as defined). Upon the occurrence of a change of control (as defined), (i) all earned units will vest (no longer be subject to Plains AAP, L.P. s call right), (ii) to the extent any of the units granted prior to 2009 are unearned at the time, an incremental 25% of the units originally awarded will vest, (iii) if none of the units granted in 2009 have been earned at the time, 37.5% will vest, (iv) if 37.5% of the units granted in 2009 have been earned at the time, then an additional 37.5% will vest and (v) if 75% of the units granted in 2009 have been earned at the time, then the remaining 25% will vest. All earned Class B units will also vest if they remain outstanding as of January 1, 2016 or Plains AAP, L.P. elects not to timely exercise its call right.

Transactions with Related Persons

Vulcan Energy

As of December 31, 2009, Vulcan Energy and its affiliates owned approximately 50.1% of our general partner interest, as well as approximately 9% of our outstanding limited partner units.

Voting Agreement. In August 2005, Vulcan Energy s ownership interest in our general partner increased from 44% to over 50%. At the closing of the transaction, Vulcan Energy entered into a voting agreement that restricts its ability to unilaterally elect or remove the independent directors serving on our audit committee and separately, our CEO and COO agreed, subject to certain ongoing conditions, to waive certain change-of-control payment rights that would otherwise have been triggered by the increase in Vulcan Energy s ownership interest. These ownership changes to our general partner had no material impact on us.

Another owner of GP LLC, Lynx Holdings I, LLC, agreed to restrict certain of its voting rights with respect to its approximate 1.4% membership interest in GP LLC. See Item 10. Directors and Executive Officers of Our General Partner and Corporate Governance Partnership Management and Governance.

Administrative Services Agreement. On October 14, 2005, GP LLC and Vulcan Energy entered into an Administrative Services Agreement, effective as of September 1, 2005 (the Services Agreement). Pursuant to the Services Agreement, GP LLC provides administrative services to Vulcan Energy for consideration of an annual fee, plus certain expenses. Effective October 1, 2006, the annual fee for providing these services was increased to $1 million. Beginning in October 2008, the Services Agreement automatically renews for successive one-year periods unless either party provides written notice of its intention to terminate the Services Agreement. Pursuant to the agreement, Vulcan Energy has appointed certain employees of GP LLC as officers of Vulcan Energy for administrative efficiency. Under the Services Agreement, Vulcan Energy acknowledges that conflicts may arise between itself and GP LLC. If GP LLC believes that a specific service is in conflict with the best interest of GP LLC

Table of Contents

or its affiliates then GP LLC is entitled to suspend the provision of that service and such a suspension will not constitute a breach of the Services Agreement.

Omnibus Agreement. PAA, GP LLC, certain affiliated entities and Vulcan Energy are parties to an amended and restated omnibus agreement dated as of July 23, 2004. Pursuant to this agreement, Vulcan Energy has agreed, so long as Vulcan Energy or any of its affiliates owns an interest, directly or indirectly, in GP LLC, not to engage in or acquire any business engaged in the following activities:

- crude oil storage, terminalling and gathering activities in any state in the United States (except for Hawaii), the Outer Continental Shelf of the United States or any province or territory in Canada, for any person other than entities affiliated with Vulcan Energy and its affiliates (collectively, the Vulcan entities) or GP LLC, PAA, its operating partnerships and any controlled affiliates (collectively, the Plains entities);

- crude oil marketing activities; and

- transportation of crude oil by pipeline in any state in the United States (except for Hawaii), the Outer Continental Shelf of the United States or any province or territory in Canada, for any person other than the Plains entities.

These restrictions are subject to specified permitted exceptions and may be terminated by Vulcan Energy upon certain change of control events involving Vulcan Energy. The omnibus agreement further permits, except as otherwise restricted by the omnibus agreement or any other agreement, each Vulcan entity to engage in any business activity, including those that may be in direct competition with the Plains entities. Further, any owner of equity interests in Vulcan Energy may make passive investments in PAA s competitors so long as such owner does not directly or indirectly use any knowledge or confidential information it received through the ownership by a Plains entity to compete, or to engage in or become interested financially in any person that competes, in the restricted activities described above.

Indemnification Arrangement. In 2001, in connection with the transfer of interests in our general partner, Vulcan Energy (as successor in interest to the owner of our former general partner) agreed to indemnify us for (i) any claims relating to securities laws or regulations in connection with the upstream or midstream businesses, based on acts or omissions, or alleged acts or omissions, occurring on or prior to June 8, 2001, or (ii) any claims relating to the operation of the upstream business, whenever arising. In addition, we agreed to indemnify Vulcan Energy for any claims relating to the operation of the midstream business, whenever arising.

Crude Oil Purchases. From August 2005 to May 2007, Calumet Florida L.L.C. (Calumet) was owned by Vulcan Resources Florida, Inc., the majority of which is owned by Paul G. Allen. In May 2007, Calumet was sold and ceased to be related to Vulcan Energy. In 2007, until the date that Calumet ceased to be related to Vulcan Energy, we purchased crude oil from Calumet for approximately $17 million.

Other. In addition to those relationships described above, we have engaged in other transactions with affiliates of Vulcan Energy. See Natural Gas Storage Investment.

Natural Gas Storage Investment

In September 2005, we and Vulcan Gas Storage LLC, a subsidiary of Vulcan LLC, an investment arm of Paul G. Allen, formed PAA/Vulcan Gas Storage, LLC to acquire ECI (now known as PAA Natural Gas Storage, LLC or PNGS), an indirect subsidiary of Sempra Energy, for approximately $250 million. We and Vulcan Gas Storage each made an initial cash investment of approximately $113 million and Bluewater Natural Gas Holdings, LLC, a subsidiary of PAA/Vulcan, entered into a $90 million credit facility contemporaneously with closing.

From September 2005 until September 3, 2009, we owned 50% of PAA/Vulcan and Vulcan Gas Storage LLC owned the other 50%. Giving effect to all contributions and distributions made during the period from January 1, 2007 through September 3, 2009, we and Vulcan Gas Storage each made a net contribution of $39 million. Such contributions and distributions did not result in an increase or decrease to our ownership interest.

On September 3, 2009, one of our subsidiaries acquired the remaining 50% interest in PAA/Vulcan from Vulcan Gas Storage LLC, which resulted in our ownership of a 100% interest in PNGS. The purchase price for the transaction consisted of $90 million in cash paid at closing, 1,907,305 common units issued to Vulcan Gas Storage at closing, and up to $40 million of deferred/contingent cash consideration. The deferred/contingent consideration is payable in cash in two installments of $20 million each upon achievement of certain performance milestones and events expected to occur over the next several years. At closing of the acquisition, we repaid all of PNGS s outstanding debt. Mr. Temple had a profits interest in Vulcan Gas Storage from September 2008 until December 2009. The Board of Directors appointed a conflicts committee in connection with this transaction. After engaging in a process of review and deliberation, the conflicts committee determined that the transaction was fair and reasonable. See Review, Approval or Ratification of Transactions with Related Persons below.

Tank Car Lease and CANPET

In July 2001, we acquired the assets of CANPET Energy Group Inc. (CANPET). Mr. W. David Duckett, the President of PMC (Nova Scotia) Company, the general partner of Plains Marketing Canada, L.P., owned approximately 38% of CANPET. In connection with the CANPET acquisition, Plains Marketing Canada, L.P. assumed CANPET s rights and obligations under a Master Railcar Leasing Agreement between CANPET and Pivotal Enterprises Corporation (Pivotal). The agreement provides for Plains Marketing Canada, L.P. to lease approximately 57 railcars from Pivotal at a lease price of $1,000 (Canadian) per month, per car. Mr. Duckett owns a 23% interest in Pivotal. The railcars were sold and the lease was assigned by Pivotal to the Andrews Companies LLC in 2007.

Other

During 2009, 2008 and 2007, we purchased approximately $2.2 million, $3.6 million and $1.7 million, respectively, of oil from companies owned and controlled by funds managed by KACALP. We pay the same amount per barrel to these companies that we pay to other producers in the area.

Review, Approval or Ratification of Transactions with Related Persons

Pursuant to our Governance Guidelines, a director is expected to bring to the attention of the CEO or the board any conflict or potential conflict of interest that may arise between the director or any affiliate of the director, on the one hand, and the Partnership or GP LLC on the other. The resolution of any such conflict or potential conflict should, at the discretion of the board in light of the circumstances, be determined by a majority of the disinterested directors.

If a conflict or potential conflict of interest arises between the Partnership and GP LLC, the resolution of any such conflict or potential conflict should be addressed by the board in accordance with the provisions of the Partnership Agreement. At the discretion of the board in light of the circumstances, the resolution may be determined by the board in its entirety or by a conflicts committee meeting the definitional requirements for such a committee under the Partnership Agreement. Such resolution may include resolution of any derivative conflicts created by an executive officer s ownership of interests in GP LLC or a director s appointment by an owner of GP LLC.

Pursuant to our Code of Business Conduct, any Executive Officer must avoid conflicts of interest unless approved by the board of directors.

In the case of any sale of equity by the Partnership in which an owner or affiliate of an owner of our general partner participates, our practice is to obtain general approval of the full board for the transaction. The board typically delegates authority to set the specific terms to a pricing committee, consisting of the CEO and one independent director. Actions by the pricing committee require unanimous approval.

Table of Contents

Item 14. ***Principal Accountant Fees and Services***

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

	Year Ended December 31, 2009	Year Ended December 31, 2008
Audit fees(1)	$ 3.1	$ 2.6
Audit-related fees(2)	0.2	0.2
Tax fees(3)	0.8	0.9
All other fees(4)	0.2	0.5
Total	$ 4.3	$ 4.2

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

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

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

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

Pre-Approval Policy

All services provided by our independent auditor are subject to pre-approval by our audit committee. The audit committee has instituted a policy that describes certain pre-approved non-audit services. We believe that the description of services is designed to be sufficiently detailed as to particular services provided, such that (i) management is not required to exercise judgment as to whether a proposed service fits within the description and (ii) the audit committee knows what services it is being asked to pre-approve. The audit committee is informed of each engagement of the independent auditor to provide services under the policy. All services provided by our independent auditor during the years ended December 31, 2009 and 2008 were approved in advance by our audit committee.

Table of Contents

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) (1) *Financial Statements*

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

(2) *Financial Statement Schedules*

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

(3) *Exhibits*

3.1	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 27, 2001).
3.2	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	Amendment No. 2 dated November 15, 2006 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 21, 2006).
3.4	Amendment No. 3 dated August 16, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 22, 2007).
3.5	Amendment No. 4 effective as of January 1, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed April 15, 2008).
3.6	Amendment No. 5 dated May 28, 2008 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed May 30, 2008).

3.7	Amendment No. 6 dated September 3, 2009 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 3, 2009).
3.8	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.9	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.10	Fourth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated August 7, 2008, as amended November 2, 2009 (incorporated by reference to Exhibit 3.10 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009).
3.11	Fifth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated August 7, 2008 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed August 7, 2008).
3.12	Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.13	Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).

Table of Contents

3.14	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed January 4, 2008).
4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.3	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003).
4.4	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).
4.5	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
4.6	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006).
4.7	Seventh Supplemental Indenture dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed May 12, 2006).
4.8	Eighth Supplemental Indenture dated August 25, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 25, 2006).
4.9	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).
4.10	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).
4.11	Eleventh Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed November 21, 2006).

Table of Contents

4.12	Twelfth Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.21 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.13	Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 23, 2008).
4.14	Fourteenth Supplemental Indenture dated July 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.15 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
4.15	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 20, 2009).
4.16	Sixteenth Supplemental Indenture (4.25% Senior Notes due 2012) dated July 23, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 23, 2009).
4.17	Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed September 4, 2009).
4.18	Indenture dated September 23, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 61/4% senior notes due 2015 (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P. s Current Report on Form 8-K filed September 28, 2005).
4.19	First Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed November 21, 2006).
4.20	Second Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.22 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.21	Registration Rights Agreement dated September 3, 2009 by and between Plains All American Pipeline, L.P. and Vulcan Gas Storage LLC (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-3, File No. 333-162477).

Table of Contents

10.1	Second Amended and Restated Credit Agreement dated as of July 31, 2006 by and among Plains All American Pipeline, L.P., as US Borrower; PMC (Nova Scotia) Company and Plains Marketing Canada, L.P., as Canadian Borrowers; Bank of America, N.A., as Administrative Agent; Bank of America, N.A., acting through its Canada Branch, as Canadian Administrative Agent; Wachovia Bank, National Association and J. P. Morgan Chase Bank, N.A., as Co-Syndication Agents; Fortis Capital Corp., Citibank, N.A., BNP Paribas, UBS Securities LLC, SunTrust Bank, and The Bank of Nova Scotia, as Co-Documentation Agents; the Lenders party thereto; and Banc of America Securities LLC and Wachovia Capital Markets, LLC, as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 4, 2006).
10.2	Amended and Restated Crude Oil Marketing Agreement dated as of July 23, 2004, among Plains Resources Inc., Calumet Florida Inc. and Plains Marketing, L.P. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
10.3	Amended and Restated Omnibus Agreement dated as of July 23, 2004, among Plains Resources Inc., Plains All American Pipeline, L.P., Plains Marketing, L.P., Plains Pipeline, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
10.4	Contribution, Assignment and Amendment Agreement dated as of June 27, 2001, among Plains All American Pipeline, L.P., Plains Marketing, L.P., All American Pipeline, L.P., Plains AAP, L.P., Plains All American GP LLC and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 27, 2001).
10.5	Contribution, Assignment and Amendment Agreement dated as of June 8, 2001, among Plains All American Inc., Plains AAP, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 11, 2001).
10.6	Separation Agreement dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc., Plains All American GP LLC, Plains AAP, L.P. and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed June 11, 2001).
10.7**	Pension and Employee Benefits Assumption and Transition Agreement dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed June 11, 2001).
10.8**	Plains All American GP LLC 2005 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 26, 2005).
10.9**	Plains All American GP LLC 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to Registration Statement on Form S-8, File No. 333-74920) as amended June 27, 2003 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
10.10**	Plains All American 2001 Performance Option Plan (incorporated by reference to Exhibit 99.2 to the Registration Statement on Form S-8 filed December 11, 2001, File No. 333-74920).
10.11**	Amended and Restated Employment Agreement between Plains All American GP LLC and Greg L. Armstrong dated as of June 30, 2001 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.12**	Amended and Restated Employment Agreement between Plains All American GP LLC and Harry N. Pefanis dated as of June 30, 2001 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.13	Asset Purchase and Sale Agreement dated February 28, 2001 between Murphy Oil Company Ltd. and Plains Marketing Canada, L.P. (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed May 10, 2001).

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

Table of Contents

10.15	Transportation Agreement dated August 2, 1993, among All American Pipeline Company, Texaco Trading and Transportation Inc., Chevron U.S.A. and Sun Operating Limited Partnership (incorporated by reference to Exhibit 10.10 to the Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).
10.16	First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.17	Agreement for Purchase and Sale of Membership Interest in Scurlock Permian LLC between Marathon Ashland LLC and Plains Marketing, L.P. dated as of March 17, 1999 (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.18**	Plains All American Inc. 1998 Management Incentive Plan (incorporated by reference to Exhibit 10.5 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.19**	PMC (Nova Scotia) Company Bonus Program (incorporated by reference to Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2004).
10.20**	Quarterly Bonus Program Summary (incorporated by reference to Exhibit 10.21 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.21**	Directors Compensation Summary.
10.22	Master Railcar Leasing Agreement dated as of May 25, 1998 (effective June 1, 1998), between Pivotal Enterprises Corporation and CANPET Energy Group, Inc., (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 2001).
10.23**	Form of LTIP Grant Letter (Armstrong/Pefanis) (incorporated by reference to Exhibit 10.24 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.24**	Form of LTIP Grant Letter (executive officers) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed April 1, 2005).
10.25**	Form of LTIP Grant Letter (independent directors) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed February 23, 2005).
10.26**	Form of LTIP Grant Letter (designated directors) (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed February 23, 2005).
10.27**	Form of LTIP Grant Letter (payment to entity) (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K filed February 23, 2005).
10.28**	Form of Performance Option Grant Letter (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed April 1, 2005).
10.29	Administrative Services Agreement between Plains All American GP LLC and Vulcan Energy Corporation dated October 14, 2005 (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed October 19, 2005).
10.30	Membership Interest Purchase Agreement by and between Sempra Energy Trading Corp. and PAA/Vulcan Gas Storage, LLC dated August 19, 2005 (incorporated by reference to Exhibit 1.2 to the Current Report on Form 8-K filed September 19, 2005).
10.31**	Waiver Agreement dated as of August 12, 2005 between Plains All American GP LLC and Greg L. Armstrong (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 16, 2005).

10.32**	Waiver Agreement dated as of August 12, 2005 between Plains All American GP LLC and Harry N. Pefanis (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed August 16, 2005).

Table of Contents

10.33	Excess Voting Rights Agreement dated as of August 12, 2005 between Vulcan Energy GP Holdings Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed August 16, 2005).
10.34	Excess Voting Rights Agreement dated as of August 12, 2005 between Lynx Holdings I, LLC and Plains All American GP LLC (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed August 16, 2005).
10.35**	Form of LTIP Grant Letter (executive officers) (incorporated by reference to Exhibit 10.39 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.36**	Employment Agreement between Plains All American GP LLC and John P. vonBerg dated December 18, 2001 (incorporated by reference to Exhibit 10.40 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.37**	Form of LTIP Grant Letter (audit committee members) (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 23, 2006).
10.38**	Plains All American PPX Successor Long-Term Incentive Plan (incorporated by reference to Exhibit 10.45 to the Annual Report on Form 10-K for the year ended December 31, 2006).
10.39**	Forms of LTIP Grant Letters dated February 22, 2007 (Named Executive Officers) (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2007).
10.40	First Amendment dated July 31, 2007 to the Second Amended and Restated Credit Agreement [US/Canada Facilities] by and between Plains All American Pipeline, L.P., PMC (Nova Scotia) Company, Plains Marketing Canada, L.P., Rangeland Pipeline Company, Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 6, 2007).
10.41**	Separation and Release Agreement dated August 21, 2007 between Plains All American GP LLC and George R. Coiner (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2007).
10.42**	Form of Plains AAP, L.P. Class B Restricted Units Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 4, 2008).
10.43	Second Restated Credit Agreement dated as of November 6, 2008 by among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party there to (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed November 7, 2008).
10.44	First Amendment to Second Restated Credit Agreement dated as of October 27, 2009, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, BNP Paribas, as Syndication Agent, SOCIETE GENERALE, as Documentation Agent, Banc of America Securities LLC (BAS), BNP Paribas (BNPP) and Societe Generale, as joint lead arrangers, BAS and BNPP, as joint bookrunners, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed October 29, 2009).
10.45	Restated Guaranty Agreement dated November 6, 2008 by Plains All American Pipeline, L.P. in favor of Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed November 7, 2008).
10.46	Contribution and Assumption Agreement dated December 28, 2007, by and between Plains AAP, L.P. and PAA GP LLC (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed January 4, 2008).
10.47	Assumption, Ratification and Confirmation Agreement dated January 1, 2008 by Plains Midstream Canada ULC in favor of the Lenders party to the Second Amended and Restated Credit Agreement [US/Canada Facilities], as amended (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the year ended

	December 31, 2007).
10.48**	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Greg L. Armstrong (incorporated by reference to Exhibit 10.49 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.49**	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Harry N. Pefanis (incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the year ended December 31, 2008).

Table of Contents

10.50**	First Amendment to Plains All American GP LLC 2005 Long-Term Incentive Plan dated December 4, 2008 (incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.51**	Second Amendment to Plains All American GP LLC 1998 Long-Term Incentive Plan dated December 4, 2008 (incorporated by reference to Exhibit 10.52 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.52**	Form of Amendment to LTIP grant letters (executive officers) (incorporated by reference to Exhibit 10.53 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.53**	Form of Amendment to LTIP grant letters (directors) (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the year ended December 31, 2008).
12.1	Computation of Ratio of Earnings to Fixed Charges
21.1	List of Subsidiaries of Plains All American Pipeline, L.P.
23.1	Consent of PricewaterhouseCoopers LLP.
31.1	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350
101	The following financial information from the annual report on Form 10-K of Plains All American Pipeline, L.P. for the year ended December 31, 2009, formatted in XBRL (extensible Business Reporting Language): (i) Consolidated Statements of Operations, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) Consolidated Statements of Changes in Partners Capital, (v) Consolidated Statements of Comprehensive Income, (vi) Consolidated Statements of Changes in Accumulated Other Comprehensive Income and (vii) Notes to the Consolidated Financial Statements, tagged as blocks of text.

Filed herewith

** Management compensatory plan or arrangement

Table of Contents

SIGNATURES

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

PLAINS ALL AMERICAN PIPELINE, L.P.

	By:	PAA GP LLC, *its general partner*
	By:	Plains AAP, L.P., *its sole member*
	By:	PLAINS ALL AMERICAN GP LLC, *its general partner*
	By:	/s/ GREG L. ARMSTRONG **Greg L. Armstrong,** ***Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)***
February 26, 2010		
	By:	/s/ AL SWANSON **Al Swanson,** ***Senior Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)***
February 26, 2010		

Table of Contents

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

Name	Title	Date
/s/ GREG L. ARMSTRONG Greg L. Armstrong	Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)	February 26, 2010
/s/ HARRY N. PEFANIS Harry N. Pefanis	President and Chief Operating Officer of Plains All American GP LLC	February 26, 2010
/s/ AL SWANSON Al Swanson	Senior Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)	February 26, 2010
/s/ TINA L. SUMMERS Tina L. Summers	Vice President Accounting and Chief Accounting Officer of Plains All American GP LLC (Principal Accounting Officer)	February 26, 2010
/s/ EVERARDO GOYANES Everardo Goyanes	Director of Plains All American GP LLC	February 26, 2010
/s/ T. GEOFF MCKAY T. Geoff McKay	Director of Plains All American GP LLC	February 26, 2010
/s/ GARY R. PETERSEN Gary R. Petersen	Director of Plains All American GP LLC	February 26, 2010
/s/ ROBERT V. SINNOTT Robert V. Sinnott	Director of Plains All American GP LLC	February 26, 2010
/s/ ARTHUR L. SMITH Arthur L. Smith	Director of Plains All American GP LLC	February 26, 2010
/s/ J. TAFT SYMONDS J. Taft Symonds	Director of Plains All American GP LLC	February 26, 2010

/s/ CHRISTOPHER M. TEMPLE Christopher M. Temple	Director of Plains All American GP LLC	February 26, 2010

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS

	Page
Consolidated Financial Statements	
Management s Report on Internal Control Over Financial Reporting	F-2
Report of Independent Registered Public Accounting Firm	F-3
Consolidated Balance Sheets as of December 31, 2009 and 2008	F-4
Consolidated Statements of Operations for the years ended December 31, 2009, 2008 and 2007	F-5
Consolidated Statements of Cash Flows for the years ended December 31, 2009, 2008 and 2007	F-6
Consolidated Statements of Changes in Partners Capital for the years ended December 31, 2009, 2008 and 2007	F-7
Consolidated Statements of Comprehensive Income for the years ended December 31, 2009, 2008 and 2007	F-8
Consolidated Statements of Changes in Accumulated Other Comprehensive Income for the years ended December 31, 2009, 2008 and 2007	F-8
Notes to the Consolidated Financial Statements	F-9

Table of Contents

MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Management has used the framework set forth in the report entitled Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) to evaluate the effectiveness of the Partnership s internal control over financial reporting. Based on that evaluation, management has concluded that the Partnership s internal control over financial reporting was effective as of December 31, 2009.

The effectiveness of the Partnership s internal control over financial reporting as of December 31, 2009 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on Page F-3.

/s/ GREG L. ARMSTRONG
Greg L. Armstrong

Chairman of the Board, Chief Executive Officer and

Director of Plains All American GP LLC

(Principal Executive Officer)

/s/ AL SWANSON
Al Swanson

Senior Vice President and Chief Financial Officer of

Plains All American GP LLC

(Principal Financial Officer)

February 26, 2010

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors of the General Partner and Unitholders of

Plains All American Pipeline, L.P.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of cash flows, of changes in partners capital, of comprehensive income, and of changes in accumulated other comprehensive income, present fairly, in all material respects, the financial position of Plains All American Pipeline, L.P. and its subsidiaries at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Partnership s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

Houston, Texas
February 26, 2010

PricewaterhouseCoopers LLP

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in millions, except unit amounts)

	December 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 25	$ 11
Trade accounts receivable and other receivables, net	2,253	1,525
Inventory	1,157	801
Other current assets	223	259
Total current assets	3,658	2,596
PROPERTY AND EQUIPMENT	7,240	5,727
Accumulated depreciation	(900)	(668)
	6,340	5,059
OTHER ASSETS		
Linefill and base gas	501	425
Long-term inventory	121	139
Investment in unconsolidated entities	82	257
Goodwill	1,287	1,210
Other, net	369	346
Total assets	$ 12,358	$ 10,032
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 2,295	$ 1,507
Short-term debt (Note 4)	1,074	1,027
Other current liabilities	413	426
Total current liabilities	3,782	2,960
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	6	40
Senior notes, net of unamortized net discount of $14 and $6, respectively	4,136	3,219
Other long-term liabilities and deferred credits	275	261
Total long-term liabilities	4,417	3,520
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
PARTNERS CAPITAL		
Common unitholders (136,135,988 and 122,911,645 units outstanding, respectively)	4,002	3,469
General partner	94	83
Total partners capital excluding noncontrolling interest	4,096	3,552
Noncontrolling interest	63	
Total partners capital	4,159	3,552
Total liabilities and partners capital	$ 12,358	$ 10,032

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

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Year Ended December 31, 2009		2008		2007	
REVENUES						
Supply & Logistics segment revenues	$	17,757	$	29,348	$	19,834
Transportation segment revenues		536		556		439
Facilities segment revenues		227		157		121
Total revenues		18,520		30,061		20,394
COSTS AND EXPENSES						
Purchases and related costs		16,656		28,479		19,001
Field operating costs		638		617		531
General and administrative expenses		211		160		164
Depreciation and amortization		236		211		180
Total costs and expenses		17,741		29,467		19,876
OPERATING INCOME		779		594		518
OTHER INCOME/(EXPENSE)						
Equity earnings in unconsolidated entities		15		14		15
Interest expense (net of capitalized interest of $15, $17 and $14, respectively)		(224)		(196)		(162)
Other income, net		16		33		10
INCOME BEFORE TAX		586		445		381
Current income tax expense		(15)		(9)		(3)
Deferred income tax benefit/(expense)		9		1		(13)
NET INCOME		580		437		365
Less: Net income attributable to noncontrolling interest		(1)				
NET INCOME ATTRIBUTABLE TO PLAINS	$	579	$	437	$	365
NET INCOME ATTRIBUTABLE TO PLAINS:						
LIMITED PARTNERS	$	443	$	325	$	286
GENERAL PARTNER	$	136	$	112	$	79
BASIC NET INCOME PER LIMITED PARTNER UNIT	$	3.34	$	2.66	$	2.47
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$	3.32	$	2.64	$	2.45
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING		130		120		113
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING		131		121		114

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

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Year Ended December 31, 2009	2008 (in millions)	2007
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 580	$ 437	$ 365
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization	236	211	180
Equity compensation charge	68	24	49
Inventory valuation adjustments		168	1
Gain on sale of linefill	(4)	(3)	(12)
Gain on sale of investment assets		(12)	(4)
Deferred income tax (benefit)/expense	(9)	(1)	13
(Gain)/loss on foreign currency revaluation	(13)	22	
Equity earnings in unconsolidated entities, net of distributions	(8)	(4)	(14)
Net cash received/(paid) for terminated interest rate and foreign currency hedging instruments	(9)	15	
Net gain on purchase of remaining 50% interest in PNGS	(9)		
Other	(6)	2	1
Changes in assets and liabilities, net of acquisitions:			
Trade accounts receivable and other	(744)	668	(739)
Inventory	(319)	(120)	340
Accounts payable and other current liabilities	602	(550)	616
Net cash provided by operating activities	365	857	796
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid in connection with acquisitions, net of cash acquired (Note 3)	(219)	(709)	(127)
Additions to property, equipment and other	(460)	(589)	(548)
Investment in unconsolidated entities	(4)	(37)	(9)
Net cash paid for linefill in assets owned	(9)	(55)	(19)
Cash received for sale of noncontrolling interest in a subsidiary	26		
Proceeds from sales of assets and other	6	51	40
Net cash used in investing activities	(660)	(1,339)	(663)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings/(repayments) on revolving credit facilities	(19)	286	305
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility	20	(196)	(359)
Repayment of PNGS debt	(446)		
Proceeds from the issuance of senior notes	1,346	597	
Repayments of senior notes	(430)		
Net proceeds from the issuance of common units (Note 5)	458	315	383
Distributions paid to common unitholders (Note 5)	(468)	(418)	(370)
Distributions paid to general partner (Note 5)	(137)	(114)	(81)
Other financing activities	(12)	(6)	(2)
Net cash provided by/(used in) financing activities	312	464	(124)

Effect of translation adjustment on cash		(3)		5		4
Net increase/(decrease) in cash and cash equivalents		14		(13)		13
Cash and cash equivalents, beginning of period		11		24		11
Cash and cash equivalents, end of period	$	25	$	11	$	24
Cash paid for interest, net of amounts capitalized	$	214	$	206	$	186
Cash paid/(refunded) for income taxes, net	$	(5)	$	15	$	3

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

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS CAPITAL

(in millions)

	Common Units		General	Partners Capital Excluding Noncontrolling	Noncontrolling	Partners
	Units	Amount	Partner	Interest	Interest	Capital
Balance at December 31, 2006	**109**	**$ 2,906**	**$ 71**	**$ 2,977**	**$**	**$ 2,977**
Net income		286	79	365		365
Distributions		(370)	(81)	(451)		(451)
Issuance of common units	6	375	8	383		383
Issuance of common units under Long Term Incentive Plans (LTIP)	1	17		17		17
Class B Units of Plains AAP, L.P. (Note 10)		2	1	3		3
Other comprehensive income		127	3	130		130
Balance at December 31, 2007	**116**	**$ 3,343**	**$ 81**	**$ 3,424**	**$**	**$ 3,424**
Net income		325	112	437		437
Distributions		(418)	(114)	(532)		(532)
Issuance of common units	7	309	6	315		315
Issuance of common units under LTIP		1		1		1
Class B Units of Plains AAP, L.P. (Note 10)		12		12		12
Other comprehensive loss		(103)	(2)	(105)		(105)
Balance at December 31, 2008	**123**	**$ 3,469**	**$ 83**	**$ 3,552**	**$**	**$ 3,552**
Sale of noncontrolling interest in a subsidiary		(37)	(1)	(38)	64	26
Net income		443	136	579	1	580
Distributions		(468)	(137)	(605)		(605)
Issuance of common units	11	447	9	456		456
Issuance of common units in connection with the PNGS Acquisition	2	91	2	93		93
Issuance of common units under LTIP		12		12		12
Class B Units of Plains AAP, L.P. (Note 10)		2	3	5		5
Distribution to noncontrolling interest					(2)	(2)
Other comprehensive income		46	2	48		48
Other		(3)	(3)	(6)		(6)
Balance at December 31, 2009	**136**	**$ 4,002**	**$ 94**	**$ 4,096**	**$ 63**	**$ 4,159**

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

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Year Ended December 31, 2009	2008	2007
Net income attributable to Plains	$ 579	$ 437	$ 365
Other comprehensive income/(loss)	48	(105)	130
Comprehensive income	$ 627	$ 332	$ 495

CONSOLIDATED STATEMENTS OF CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)

	Derivative Instruments	Translation Adjustments	Other	Total
Balance at December 31, 2006	$ (20)	$ 70	$	$ 50
Reclassification adjustments	11			11
Net deferred gain on cash flow hedges	13			13
Currency translation adjustment		106		106
2007 Activity	24	106		130
Balance at December 31, 2007	$ 4	$ 176	$	$ 180
Reclassification adjustments	46			46
Net deferred gain on cash flow hedges	111			111
Currency translation adjustment		(262)		(262)
2008 Activity	157	(262)		(105)
Balance at December 31, 2008	$ 161	$ (86)	$	$ 75
Reclassification adjustments	8			8
Net deferred loss on cash flow hedges	(151)			(151)
Currency translation adjustment		192		192
Proportionate share of our unconsolidated entities other comprehensive loss			(1)	(1)
2009 Activity	(143)	192	(1)	48
Balance at December 31, 2009	$ 18	$ 106	$ (1)	$ 123

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

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Organization and Basis of Presentation

Organization

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

We are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products. We refer to liquefied petroleum gas and other natural gas-related petroleum products collectively as LPG. We are also engaged in the development and operation of natural gas storage facilities. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. We previously referred to the Supply and Logistics segment as the Marketing segment. We revised the segment name to better describe the business activities conducted within that segment. See Note 15 for further discussion of our three operating segments.

Our 2% general partner interest is held by PAA GP LLC, a Delaware limited liability company, whose sole member is Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P. s general partner. Plains All American GP LLC manages our operations and activities and employs our domestic officers and personnel. Our Canadian officers and personnel are employed by our subsidiary PMC (Nova Scotia) Company, the general partner of Plains Marketing Canada, L.P. References to our general partner, as the context requires, include any or all of PAA GP LLC, Plains AAP, L.P. and Plains All American GP LLC. Plains AAP, L.P. and Plains All American GP LLC are essentially held by 13 owners with interests ranging from approximately 50% to less than 1%.

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present and discuss our consolidated financial position as of December 31, 2009 and 2008, and the consolidated results of our operations, cash flows, changes in partners capital, comprehensive income and changes in accumulated other comprehensive income for the years ended December 31, 2009, 2008 and 2007. All significant intercompany transactions have been eliminated in consolidation, and certain reclassifications have been made to information from previous years to conform to the current presentation. These reclassifications do not affect net income. The accompanying consolidated financial statements include Plains and all of its wholly owned subsidiaries. Investments in entities over which we have significant influence but not control are accounted for by the equity method. We evaluate our equity investments for impairment in accordance with Financial Accounting Standards Board (FASB) guidance with respect to the equity method of accounting for investments in common stock. An impairment of an equity investment results when factors indicate that the investment s fair value is less than its carrying value and the reduction in value is other than temporary in nature.

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

Note 2 Summary of Significant Accounting Policies

Use of Estimates

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

Table of Contents

Revenue Recognition

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

Additionally, we may utilize derivatives in connection with the transactions described above. For commodity derivatives that are designated as cash flow hedges, derivative gains and losses are deferred to Accumulated Other Comprehensive Income (AOCI) and recognized in revenues in the periods during which the underlying physical hedged transaction impacts earnings. For derivatives that do not qualify for hedge accounting or are not designated for hedge accounting, as well as ineffectiveness associated with cash flow hedges, are recognized in revenues each period.

Transportation Segment Revenues. Revenues from pipeline tariffs and fees are associated with the transportation of crude oil and refined products at a published tariff as well as revenues associated with line leases for committed space on a particular system that may or may not be utilized. Tariff revenues are recognized either at the point of delivery or at the point of receipt pursuant to specifications outlined in the regulated and non-regulated tariffs. Revenues associated with line-lease fees are recognized in the month to which the lease applies, whether or not the space is actually utilized and are subject to make up rights for take or pay arrangements. All pipeline tariff and fee revenues are based on actual volumes and rates. As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. In addition, we have certain agreements that require counterparties to ship a minimum volume over an agreed upon period. Revenue is recognized at the latter of when the volume is shipped (pursuant to specifications outlined in the tariffs) or when the counterparty s ability to make up the minimum volume has expired.

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

Purchases and Related Costs

Purchases and related costs include (i) the cost of crude oil, LPG and refined products obtained in outright purchases; (ii) fees incurred for third-party transportation and storage, whether by pipeline, truck, ship or barge; (iii) interest cost attributable to borrowings for inventory stored in a contango market; (iv) performance-related bonus accruals; and (v) expenses

Table of Contents

of issuing letters of credit to support these purchases. These costs are recognized when incurred except in the case of products purchased, which are recognized at the time title transfers to us.

Field Operating Costs and General and Administrative Expenses

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

Foreign Currency Transactions

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

Certain of our subsidiaries also enter into transactions and have monetary assets and liabilities that are denominated in a currency other than the entities respective functional currencies. Gains and losses from the revaluation of foreign currency transactions and monetary assets and liabilities are included in the consolidated statements of operations. The revaluation of foreign currency transactions and monetary assets and liabilities resulted in a gain of approximately $13 million for the year ended December 31, 2009, a loss of approximately $22 million for the year ended December 31, 2008 and a gain of less than $1 million for the year ended December 31, 2007.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less and typically exceed federally insured limits. We periodically assess the financial condition of the institutions where these funds are held and believe that our credit risk is minimal. In accordance with our policy, outstanding checks are classified as accounts payable rather than negative cash. As of December 31, 2009 and 2008, accounts payable included approximately $50 million and $44 million, respectively, of outstanding checks that were reclassified from cash and cash equivalents.

Accounts Receivable

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

During the last two years, U.S. and world financial markets and energy prices were extremely volatile and global economies substantially weakened. This financial market volatility combined with the fluctuation in energy prices experienced over the past two years has caused liquidity issues impacting many companies, which in turn have increased the potential credit risks associated with certain counterparties with which we do business.

To mitigate such credit risks, we have in place a rigorous credit review process. We closely monitor these conditions in order to make a determination with respect to the amount, if any, of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit, parental guarantees or advance cash payments. At December 31, 2009 and 2008, we had received approximately $212 million and $66 million, respectively, of advance cash payments from third parties to mitigate credit risk. In addition, we enter into netting arrangements with our counterparties. These arrangements cover a significant part of our transactions and also serve to mitigate credit risk.

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted. At December 31, 2009 and 2008, substantially all of our net accounts receivable were less than 60 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled $9 million and $5 million at December 31, 2009 and 2008, respectively. Although we consider our allowance for doubtful trade accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

Inventory, Linefill, Base Gas and Long-term Inventory

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

At the end of each reporting period we assess the carrying value of our inventory and make any adjustments necessary to reduce the carrying value to the applicable net realizable value. During 2008 and 2007, we recorded non-cash charges of approximately $168 million and $1 million, respectively, related to the writedown of such inventory. During 2009, no such writedowns were recognized. Linefill, base gas and minimum working inventory requirements in assets we own are recorded at historical cost and consist of crude oil, LPG and natural gas. (See Note 3 for the fair value of assets and liabilities recognized as part of the PNGS acquisition.) Linefill is used to pack the pipeline such that when an incremental product is injected into or enters a pipeline it forces product out at another location. Base gas requirements of natural gas, as well as the minimum amount of crude oil and refined products is used to operate our storage and terminalling facilities, similar to linefill in the pipelines. During 2009, 2008 and 2007, we recorded gains of approximately $4 million, $3 million and $12 million, respectively, on the sale of pipeline linefill for proceeds of approximately $24 million, $23 million and $20 million, respectively.

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

Inventory, linefill, base gas and long term inventory consisted of the following (barrels in thousands, cubic feet in millions and total value in millions):

Table of Contents

	December 31, 2009				December 31, 2008			
	Volumes	Unit of Measure	Total Value	Price/ Unit (1)	Volumes	Unit of Measure	Total Value	Price/ Unit (1)
Inventory								
Crude oil	12,232	barrels	$ 886	$ 72.43	9,986	barrels	$ 421	$ 42.16
LPG	6,051	barrels	247	$ 40.82	7,748	barrels	370	$ 47.75
Refined products	283	barrels	21	$ 74.20	103	barrels	5	$ 48.54
Natural gas (2) (3)	181	cubic feet	1	$ 3.30		cubic feet		N/A
Parts and supplies	N/A		2	N/A	N/A		5	N/A
Inventory subtotal			1,157				801	
Linefill and base gas								
Crude oil	9,404	barrels	471	$ 50.09	9,148	barrels	422	$ 46.13
Natural gas (2) (3)	9,194	cubic feet	28	$ 3.04		cubic feet		N/A
LPG	52	barrels	2	$ 38.46	67	barrels	3	$ 44.78
Linefill and base gas subtotal			501				425	
Long-term inventory								
Crude oil	1,497	barrels	103	$ 68.80	1,781	barrels	121	$ 67.94
LPG	458	barrels	18	$ 39.30	363	barrels	18	$ 49.59
Long-term inventory subtotal			121				139	
Total			$ 1,779				$ 1,365	

(1) Price per unit represents a weighted average associated with various grades, qualities and locations; accordingly, these prices may not be comparable to published benchmarks for such products.

(2) To account for the 6:1 mcf of natural gas to crude oil barrel ratio, the natural gas volumes can be converted to barrels by dividing by 6.

(3) In September 2009, we acquired the remaining 50% indirect interest in PAA Natural Gas Storage, LLC (PNGS). We historically accounted for our 50% indirect interest in PNGS under the equity method. As such, we did not have direct ownership of PNGS s natural gas inventory or base gas. See Note 3 to our Consolidated Financial Statements for additional discussion regarding the PNGS acquisition.

Property, Plant and Equipment

In accordance with our capitalization policy, costs associated with acquisitions and improvements that expand our existing capacity, including related interest costs, are capitalized. For the years ended December 31, 2009, 2008 and 2007, capitalized interest was $15 million, $17 million and $14 million, respectively. We also capitalize expenditures for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production, and/or functionality of our existing assets. Repair and maintenance expenditures incurred in order to maintain the day to day operation of our existing assets are expensed as incurred.

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

	Estimated Useful Lives (Years)	December 31, 2009	December 31, 2008
Crude oil pipelines and facilities	30 - 50	$ 4,535	$ 3,934
Storage and terminal facilities	30 - 70	1,735	944
Trucking equipment and other	5 - 15	331	255
Construction in progress		476	474
Office property and equipment	3 - 5	84	75
Land and other	N/A	79	45
		7,240	5,727
Less accumulated depreciation		(900)	(668)
Property and equipment, net		$ 6,340	$ 5,059

Depreciation expense for the years ended December 31, 2009, 2008 and 2007 was $216 million, $196 million and $160 million, respectively.

Table of Contents

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

Equity Method of Accounting

Our investments in Frontier Pipeline Company (Frontier), Settoon Towing, LLC (Settoon Towing) and Butte Pipe Line Company (Butte) are accounted for under the equity method of accounting. Our ownership interests in Frontier, Settoon Towing and Butte are 22%, 50% and 22%, respectively. We do not consolidate any part of the assets or liabilities of our equity investees. Our share of net income or loss is reflected as one line item on the income statement and will increase or decrease, as applicable, the carrying value of our investments on the balance sheet. In addition, we include a proportionate share of our equity method investees unrealized gains and losses in other comprehensive income on our consolidated balance sheet. We also adjust our investment balances in these investees by the like amount. Distributions to the Partnership will reduce the carrying value of our investments and will be reflected on our cash flow statement netted against equity in earnings. In turn, contributions will increase the carrying value of our investments and will be reflected on our cash flow statement within investing activities.

Noncontrolling Interest

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

Asset Retirement Obligations

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

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

A small portion of our contractual or regulatory obligations is related to assets that are inactive or that we plan to take out of service and, although the ultimate timing and costs to settle these obligations are not known with certainty, we have recorded a reasonable estimate of these obligations. We have estimated that the fair value of these obligations was approximately $5 million at December 31, 2009 and 2008.

Table of Contents

Impairment of Long-Lived Assets

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

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

- whether there is an indication of impairment;
- the grouping of assets;
- the intention of holding 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 2009, we recognized impairments of less than $1 million for assets taken out of service. Impairments of approximately $5 million and less than $1 million were recognized during 2008 and 2007, 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.

Goodwill

In accordance with FASB guidance, we test goodwill at least annually (as of June 30) and on an interim basis if a triggering event occurs, such as an adverse change in business climate, to determine whether an impairment has occurred. Goodwill is tested for impairment at a level of

reporting referred to as a reporting unit. A reporting unit is an operating segment or one level below an operating segment for which discrete financial information is available and regularly reviewed by segment management. Our reporting units are our operating segments.
FASB guidance requires a two step approach to testing goodwill for impairment. In Step 1, we compare the fair value of the reporting unit with the respective book values, including goodwill, by using an income approach based on a discounted cash flow analysis. This approach requires us to make long-term forecasts of future revenues, expenses and other expenditures. Those forecasts require the use of various assumptions and estimates, the most significant of which are net revenues (total revenues less purchases and related costs), operating expenses, general and administrative expenses and the weighted-average cost of capital. Fair value of the reporting units is determined using significant unobservable inputs, or level 3 inputs in the fair value hierarchy. When the fair value is greater than book value, then the reporting unit s goodwill is not considered impaired. If the book value is greater than fair value, then we proceed to Step 2. In Step 2, we compare the implied fair value of the reporting unit s goodwill with the book value. A goodwill impairment loss is recognized if the carrying amount exceeds its fair value.

In addition, there is a potential indicator of impairment if a company s market capitalization is less than its book equity. Periodically, we compare our market capitalization to our book equity to determine if there is an indicator of potential impairment. Throughout 2009, our market capitalization exceeded the book value of our equity and thus, this indicated that there was no triggering event. There were no other indicators of potential impairment of our goodwill during 2009.

Through Step 1 of our annual testing of goodwill for potential impairment, we determined that the fair value of each reporting unit was greater than its respective book value, and therefore goodwill was not considered impaired.

Table of Contents

We will continue to monitor various potential indicators (including the financial markets) to determine if a triggering event occurs and will perform another goodwill impairment analysis if necessary. We have not recognized any impairment of goodwill during the last three years.

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

	Transportation	Facilities	Supply & Logistics	Total (1)
Balance at December 31, 2007	**$ 404**	**$ 283**	**$ 385**	**$ 1,072**
2008 Goodwill Related Activity:				
Rainbow acquisition	194			194
Purchase accounting adjustments (2)			(12)	(12)
Foreign currency translation adjustments	(36)		(8)	(44)
Balance at December 31, 2008	**$ 562**	**$ 283**	**$ 365**	**$ 1,210**
2009 Goodwill Related Activity:				
PNGS acquisition		25		25
Other acquisitions	24			24
Purchase accounting adjustments (2)	(3)			(3)
Foreign currency translation adjustments	25		6	31
Balance at December 31, 2009	**$ 608**	**$ 308**	**$ 371**	**$ 1,287**

(1) As of December 31, 2009, we do not have any accumulated impairment losses.

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

Other Assets, Net

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

	2009	2008
Debt issue costs	$ 42	$ 34
Fair value of derivative instruments	77	148
Intangible assets	239	191
Other	65	10

		423		383
Less accumulated amortization		(54)		(37)
	$	369	$	346

Table of Contents

Costs incurred in connection with the issuance of long-term debt and amendments to our credit facilities are capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the effective interest method of amortization. Fully amortized debt issue costs and the related accumulated amortization are written off in conjunction with the refinancing or termination of the applicable debt arrangement. We capitalized debt issue costs of approximately $12 million and $7 million in 2009 and 2008, respectively.

Amortization expense related to other assets (including finite-lived intangible assets) for the three years ended December 31, 2009, 2008 and 2007 was $19 million, $21 million and $13 million, respectively. Our amortization expense for finite-lived intangible assets for the years ended December 31, 2009, 2008 and 2007 was $14 million, $15 million and $10 million, respectively.

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

		December 31, 2009			December 31, 2008		
	Estimated Useful Lives (Years)	Cost	Accumulated amortization	Net	Cost	Accumulated amortization	Net
Customer contracts and relationships	1-30	$ 171	$ (36)	$ 135	$ 151	$ (24)	$ 127
Emission reduction credits (1)	N/A	45		45	40		40
Property tax abatement	13	23	(1)	22			
		$ 239	$ (37)	$ 202	$ 191	$ (24)	$ 167

(1) Emission reduction credits are finite lived and are subject to amortization from the date that they are first utilized. At December 31, 2009, none of our emission reduction credits were being utilized because the projects for which they were acquired are not in service.

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

2010	$ 14
2011	$ 11
2012	$ 10
2013	$ 10
2014	$ 10

Environmental Matters

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

We expense expenditures that relate to an existing condition caused by past operations that do not contribute to current or future profitability. We record environmental liabilities assumed in business combinations based on the estimated fair value of the environmental obligations caused by past operations of the acquired company. See Note 12 for further discussion of environmental remediation matters.

Income and Other Taxes

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

We estimate (i) income taxes in the jurisdictions in which we operate, (ii) net deferred tax assets and liabilities based on temporary differences that are expected to be recovered or settled at the enacted tax rates expected in future periods, (iii) valuation allowances for deferred tax assets and (iv) contingent tax liabilities for estimated exposures related to our current tax positions. We have not recorded a valuation allowance against our deferred tax assets as we believe that it is more likely than not that they will be realized.

We adopted the provisions of the FASB guidance related to accounting for uncertainty in income taxes on January 1, 2007. Pursuant to this guidance, we must recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits of the tax position and also the past administrative practices and precedents of the taxing authority. As of December 31, 2009 and 2008, we have not recognized any material amounts in connection with uncertainty in income taxes.

Table of Contents

Recent Accounting Pronouncements

In June 2009, the FASB issued guidance to establish the source of authoritative generally accepted accounting principles to be applied by nongovernmental entities in the preparation of financial statements. As this guidance is meant to establish the source of authoritative GAAP and to better organize current accounting guidance, it only affects the referencing to applicable guidance throughout the accompanying consolidated financial statements and the notes thereto. This guidance was effective for interim or annual periods ending after September 15, 2009; therefore, we adopted this guidance as of July 1, 2009. Our adoption did not have any material impact on our financial position, results of operations or cash flows.

In May 2009, the FASB issued guidance that establishes general standards of accounting for and disclosure of subsequent events or events that occur after the balance sheet date but before financial statements are issued. This guidance sets forth (i) the period after the balance sheet date during which management shall evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, (ii) the circumstances under which an entity shall recognize events or transactions occurring after the balance sheet date in its financial statements and (iii) the disclosures that an entity shall make about events or transactions that occurred after the balance sheet date. This guidance was effective for interim or annual periods ending after June 15, 2009; therefore, we adopted this guidance as of April 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB issued guidance that increases the frequency of fair value disclosures from annual to quarterly in an effort to provide financial statement users with more timely and transparent information about the effects of current market conditions on financial instruments. This is intended to address concerns raised by some financial statement users about the lack of comparability resulting from the use of different measurement attributes for financial instruments. These disclosures are also intended to stimulate more robust discussions about financial instrument valuations between users and reporting entities. We adopted this guidance as of April 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

In November 2008, the FASB issued guidance that addresses certain accounting considerations, including initial measurement, decreases in investment value, and changes in the level of ownership or degree of influence related to equity method investments. We adopted this guidance as of January 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

In April 2008, the FASB issued guidance that amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under previous guidance over goodwill and other intangible assets. The intent of this guidance is to improve the consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure the fair value of the asset under generally accepted accounting principles. We adopted this guidance as of January 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

In March 2008, the FASB issued guidance that amends previous guidance with respect to disclosures of derivative instruments and hedging activities. This guidance requires enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under the guidance and its related interpretations and (iii) how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. The provisions of this guidance were effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted this guidance as of January 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows. See Note 6 for enhanced disclosure of derivative instruments and hedging activities.

In March 2008, the FASB issued guidance that addresses the application of the two-class method in determining income per unit for master limited partnerships having multiple classes of securities that may participate in partnership

Table of Contents

distributions. The two-class method is an earnings allocation formula that determines earnings per unit for each class of common units and participating securities according to participation rights in undistributed earnings. We adopted this guidance as of January 1, 2009. This guidance has been applied retrospectively for all financial statement periods presented. Adoption impacted the net income available to limited partners used in our computation of earnings per unit, but did not impact our net income, distributions to limited partners, financial position, results of operations or cash flows.

In December 2007, the FASB issued guidance regarding accounting for noncontrolling interests in consolidated financial statements. This guidance requires all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. The guidance eliminates the diversity that currently exists in accounting for transactions between an entity and noncontrolling interests by requiring that they be treated as equity transactions. The provisions of this guidance were effective on a prospective basis for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. We adopted this guidance as of January 1, 2009. Such adoption did not have any material impact on our consolidated financial position, results of operations or cash flows.

In December 2007, the FASB issued further guidance regarding accounting for business combinations. This guidance establishes principles and requirements for how an acquirer (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The provisions of this guidance were effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. We adopted this guidance as of January 1, 2009. Adoption has impacted our accounting for acquisitions subsequent to that date.

Derivative Instruments and Hedging Activities

We identify the risks that underlie our core business activities and utilize risk management strategies to mitigate those risks when we determine that there is value in doing so. We use various derivative instruments to (i) manage our exposure to commodity price risk as well as to optimize our profits, (ii) manage our exposure to interest rate risk and (iii) manage our exposure to currency exchange-rate risk. We record all open derivative instruments on the balance sheet as either assets or liabilities measured at their fair value per the guidance issued by the FASB. This guidance requires that changes in the fair value of derivative instruments be recognized currently in earnings unless specific hedge accounting criteria are met, in which case, changes in fair value of cash flow hedges are deferred in AOCI and reclassified into earnings when the underlying transaction affects earnings. Accordingly, changes in fair value are included in current period earnings for (i) derivatives that do not qualify for hedge accounting and (ii) the portion of cash flow hedges that are not highly effective in offsetting changes in cash flows of hedged items. See Note 6 for further discussion.

Net Income Per Limited Partner Unit

Basic and diluted net income per unit is determined by dividing our limited partners interest in net income by the weighted average number of limited partner units outstanding during the period. Pursuant to guidance issued by the FASB on the application of the two-class method for master limited partnerships (MLPs), the limited partners interest in net income attributable to Plains is calculated by first reducing net income by the distribution pertaining to the current period s net income, which is to be paid in the subsequent quarter (including the incentive distribution interest in excess of the 2% general partner interest). Then, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner and limited partners in accordance with the contractual terms of the partnership agreement. The adoption of this guidance resulted in a change to our calculation of earnings per unit by using distributions applicable to the period rather than distributions paid in the period (applicable to the previous period). Also, in accordance with this guidance, earnings per unit for prior periods were recast to conform to this revised calculation.

Table of Contents

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the years ended 2009, 2008, and 2007:

	Year Ended December 31, 2009	2008	2007
Numerator for basic and diluted earnings per limited partner unit:			
Net income attributable to Plains	$ 579	$ 437	$ 365
Less: General partner s incentive distribution paid (1)	(127)	(106)	(73)
Subtotal	452	331	292
Less: General partner 2% ownership (1)	(9)	(6)	(6)
Net income available to limited partners	443	325	286
Adjustment in accordance with application of the two-class method for MLPs (1)	(9)	(5)	(8)
Net income available to limited partners in accordance with the application of the two-class method for MLPs	$ 434	$ 320	$ 278
Denominator:			
Basic weighted average number of limited partner units outstanding	130	120	113
Effect of dilutive securities:			
Weighted average LTIP units (2)	1	1	1
Diluted weighted average number of limited partner units outstanding	131	121	114
Basic net income per limited partner unit	$ 3.34	$ 2.66	$ 2.47
Diluted net income per limited partner unit	$ 3.32	$ 2.64	$ 2.45

(1) We calculate net income available to limited partners based on the distribution paid during the current quarter (including the incentive distribution interest in excess of the 2% general partner interest). However, FASB guidance requires that the distribution pertaining to the current period s net income, which is to be paid in the subsequent quarter, be utilized in the earnings per unit calculation. After adjusting for this distribution, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner and limited partners in accordance with the contractual terms of the partnership agreement for earnings per unit calculation purposes. We reflect the impact of the difference in (i) the distribution utilized and (ii) the calculation of the excess 2% general partner interest as the Adjustment in accordance with application of the two-class method for MLPs.

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

Note 3 Acquisitions and Dispositions

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

2009 Acquisitions

PNGS Acquisition. On September 3, 2009, we acquired the remaining 50% indirect interest in PAA Natural Gas Storage, LLC (PNGS) for an aggregate purchase price of $215 million (PNGS Acquisition). The $215 million purchase price consisted of $90 million in cash paid at closing, approximately $91 million in equivalent value of PAA common units (1,907,305 PAA common units based on a 20 business-day average closing price per unit) issued to Vulcan at closing, and up to $40 million of deferred/contingent cash consideration. The deferred/contingent consideration is payable in cash in two installments of $20 million each upon the achievement of certain performance milestones and events expected to occur over the next several years. The fair value of this contingent consideration is approximately $34 million. As a result of the transaction, we now own 100% of PNGS s natural gas storage business and related operating entities, which are accounted for on a consolidated basis beginning in September 2009. We historically accounted for our 50% indirect interest in PNGS under the equity method. We recorded a net gain of approximately $9 million, recorded in other income, in connection with (i) adjusting our previously owned 50% investment in PNGS to fair value and (ii) terminating an agreement to supply natural gas to PNGS.

PNGS currently owns and operates two natural gas storage facilities located in Louisiana and Michigan that have an aggregate working gas storage capacity of 40 billion cubic feet (Bcf) and an aggregate peak injection and withdrawal capacity of 1.7 Bcf per day and 3.2 Bcf per day, respectively. PNGS also leases storage capacity and pipeline transportation capacity from third parties from time to time in order to increase its operational flexibility and enhance the services it offers its customers. As of December 31, 2009, PNGS had 3 Bcf of storage capacity under lease from third parties and had secured the right to 379 MMcf per day of firm transportation service on various

Table of Contents

pipelines. Substantially all of PNGS s revenues are derived from the provision of firm storage services under multi-year, fee-based contracts. The gas storage operations are reflected in our facilities segment.

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

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

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(1) The deferred contingent cash consideration is payable in cash in two installments of $20 million each upon the achievement of certain performance milestones and events expected to occur over the next several years. The fair value of the deferred contingent cash consideration was based on a discounted cash flow model utilizing a discount rate of approximately 9%.

The allocation of fair value to the assets and liabilities acquired in the PNGS Acquisition is as follows (in millions):

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

Other 2009 Acquisitions. During 2009, we completed six additional acquisitions for an aggregate consideration of approximately $178 million. These acquisitions included an additional 21% undivided joint interest in Capline and associated tankage, as well as various crude oil pipelines and pipeline systems that are all included within our transportation segment. We also acquired a natural gas processing business, a refined products terminal and various crude oil storage tanks and other related assets that are all included within our facilities segment. The goodwill associated with such acquisitions was approximately $24 million. As of December 31, 2009, purchase price allocations have not been finalized for all acquisitions.

2008 Acquisitions

Rainbow. In May 2008, we completed the acquisition of Rainbow Pipe Line Company, Ltd. (Rainbow) for approximately $687 million (the Canadian dollar (CAD) to U.S. dollar (USD) foreign exchange rate at the date of closing was $0.993:1). The assets acquired include approximately (i) 480 miles of mainline crude oil pipelines, (ii) 119 miles of gathering pipelines, (iii) 570,000 barrels of tankage along the system and (iv) 1 million barrels of crude oil linefill. The system has a throughput capacity of approximately 200,000 barrels per day. The acquired operations are reflected primarily in our transportation segment. The goodwill associated with this acquisition was approximately

$194 million. In anticipation of closing the Rainbow acquisition, we entered into forward currency exchange contracts, which exchanged Canadian dollars and U.S. dollars, to hedge the foreign currency exchange risk inherent in the acquisition price. Additionally, we entered into a financial option strategy, whereby we established a minimum and maximum per barrel price to hedge the commodity price risk associated with the anticipated purchase of crude oil linefill. We recognized a gain on those positions of approximately $8 million and $3 million, respectively, which is reflected in our consolidated results of operations in the Interest income and other income (expense), net line.

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

Table of Contents

Cash payment to sellers	$	659
Assumption of Rainbow debt (at estimated fair value)		26
Estimated transaction costs		2
Total purchase price	$	687

The purchase price allocation is as follows (in millions):

Property, plant and equipment	$	425
Pipeline linefill in owned assets		143
Intangible assets		52
Goodwill		191
Future income tax liability		(110)
Assumption of working capital and other long-term assets and liabilities, including cash (1)		(14)
Total	$	687

(1) Includes approximately $16 million associated with environmental liabilities.

During 2008, we completed one additional acquisition for aggregate consideration of approximately $44 million. This acquisition is reflected in our facilities segment and included the purchase of a storage facility and other assets. There was no goodwill associated with this acquisition.

2007 Acquisitions

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

Dispositions

During 2009, 2008 and 2007, we sold various property and equipment for proceeds totaling approximately $4 million, $12 million and $13 million, respectively. A loss of less than $1 million, a gain of approximately $6 million and a loss of $7 million were recognized in 2009, 2008 and 2007, respectively, related to these sales.

Table of Contents

Note 4 Debt

Debt consists of the following (in millions):

	December 31, 2009	December 31, 2008
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 2.5% and 2.3% at December 31, 2009 and 2008, respectively	$ 300	$ 280
Senior unsecured revolving credit facility, bearing interest at a rate of 0.8% and 1.1% at December 31, 2009 and 2008, respectively (1)	772	746
Other	2	1
Total short-term debt	1,074	1,027
Long-term debt:		
4.75% senior notes due August 2009 (2)		175
4.25% senior notes due September 2012 (3)	500	
7.75% senior notes due October 2012	200	200
5.63% senior notes due December 2013	250	250
7.13 % senior notes due June 2014 (4)		250
5.25% senior notes due June 2015	150	150
6.25% senior notes due September 2015	175	175
5.88% senior notes due August 2016	175	175
6.13% senior notes due January 2017	400	400
6.50% senior notes due May 2018	600	600
8.75% senior notes due May 2019	350	
5.75% senior notes due January 2020	500	
6.70% senior notes due May 2036	250	250
6.65% senior notes due January 2037	600	600
Unamortized premium/(discount), net	(14)	(6)
Long-term debt under credit facilities and other (1)	6	40
Total long-term debt (1) (5)	4,142	3,259
Total debt	$ 5,216	$ 4,286

(1) At December 31, 2009 and 2008, we have classified $772 million and $746 million, respectively, of borrowings under our senior unsecured revolving credit facility as short-term. These borrowings are designated as working capital borrowings, must be repaid within one year, and are primarily for hedged LPG and crude oil inventory and New York Mercantile Exchange (NYMEX) and IntercontinentalExchange (ICE) margin deposits.

(2) We repaid our $175 million 4.75% senior notes on August 15, 2009.

(3) These notes were issued in July 2009 and the proceeds are being used to supplement capital available from our hedged inventory facility. At December 31, 2009, approximately $222 million had been used to fund hedged inventory and would be classified as short-term debt if funded on our credit facilities.

(4) On October 5, 2009 we redeemed all of our outstanding $250 million 7.13% senior notes due 2014. In conjunction with the early redemption, we recognized a loss of approximately $4 million.

(5) Our fixed rate senior notes have a face value of approximately $4.2 billion as of December 31, 2009. We estimate the aggregate fair value of these notes as of December 31, 2009 to be approximately $4.4 billion. Our fixed-rate senior notes are traded among institutions, which trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near year end.

Table of Contents

Credit Facilities

In October 2009, we renewed our 364-day committed hedged inventory credit facility, which matures in October 2010. The new committed facility replaced a similar $525 million facility that was scheduled to mature on November 5, 2009. The new facility has a borrowing capacity of $500 million, which may be increased to $1.2 billion subject to obtaining additional lender commitments. Borrowings under this facility will be used to finance the purchase of hedged crude oil inventory for storage activities and foreign imports. At December 31, 2009, borrowings of approximately $300 million were outstanding under this facility. At December 31, 2008, borrowings of approximately $280 million were outstanding under our previous $525 million committed hedged inventory facility.

As of both December 31, 2009 and 2008, the aggregate borrowing capacity of our senior unsecured revolving credit facility was $1.6 billion (including the sub-facility for Canadian borrowings of $600 million). This credit facility has a maximum debt coverage ratio of 4.75 to 1.0 (5.5 to 1.0 during an acquisition period) and a maturity date of July 2012. Also, the senior unsecured revolving credit facility can be expanded to $2.0 billion, subject to additional lender commitments. At December 31, 2009 and 2008, amounts outstanding under this facility and together with committed letters of credit were $849 million and $836 million, respectively.

Senior Notes

In September 2009, we completed the issuance of $500 million of 5.75% senior notes due January 15, 2020. The senior notes were sold at 99.523% of face value. Interest payments are due on January 15 and July 15 of each year, beginning on January 15, 2010. 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). See Note 3 for further discussion of the PNGS Acquisition.

In July 2009, we completed the issuance of $500 million of 4.25% senior notes due September 1, 2012. The senior notes were sold at 99.802% of face value. Interest payments are due on March 1 and September 1 of each year, beginning on March 1, 2010. We used the net proceeds from this offering to supplement the capital available under our existing hedged inventory facility to fund working capital needs associated with base levels of routine foreign crude oil import and for seasonal LPG inventory requirements. Concurrent with the issuance of these senior notes, we entered into interest rate swaps whereby we receive fixed payments at 4.25% and pay three-month LIBOR plus a spread on a notional principal amount of $150 million maturing in two years and an additional $150 million notional principal amount maturing in three years.

In April 2009, we completed the issuance of $350 million of 8.75% senior notes due May 1, 2019. The senior notes were sold at 99.994% of face value. Interest payments are due on May 1 and November 1 of each year, beginning on November 1, 2009. We used the net proceeds from this offering to reduce outstanding borrowings under our credit facilities.

In April 2008, we completed the issuance of $600 million of 6.5% Senior Notes due May 1, 2018. The senior notes were sold at 99.424% of face value. Interest payments are due on May 1 and November 1 of each year, beginning on November 1, 2008. We used the net proceeds from the offering to repay amounts outstanding under our credit facilities. In November 2008, the outstanding senior notes were exchanged for similar notes registered under the Securities Act.

In each instance, the notes were co-issued by Plains All American Pipeline, L.P. and a 100% owned consolidated finance subsidiary (neither of which have independent assets or operations) and are fully and unconditionally guaranteed, jointly and severally, by most of our subsidiaries. See Note 13 for information regarding our guarantor and non-guarantor subsidiaries.

Covenants and Compliance

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

- incur indebtedness if certain financial ratios are not maintained;
- grant liens;
- engage in transactions with affiliates;

Table of Contents

- enter into sale-leaseback transactions; and
- sell substantially all of our assets or enter into a merger or consolidation.

Our senior unsecured revolving credit facility treats a change of control as an event of default and also requires us to maintain a debt-to-EBITDA coverage ratio that will not be greater than 4.75 to 1.0 on outstanding debt, and 5.5 to 1.0 on all outstanding debt during an acquisition period (generally, the period consisting of three fiscal quarters following an acquisition greater than $50 million).

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

A default under our credit facility would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit agreements, our ability to make distributions of available cash is not restricted. As of December 31, 2009, we were in compliance with the covenants contained in our credit agreements and indentures.

Letters of Credit

In connection with our crude oil supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. These letters of credit are issued under our senior unsecured revolving credit facility, and our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. At December 31, 2009 and 2008, we had outstanding letters of credit of approximately $76 million and $51 million, respectively.

Maturities

The weighted average life of our long-term debt outstanding at December 31, 2009 was approximately 11 years and the aggregate maturities for the next five years and thereafter are as follows (in millions):

Calendar Year		Payment
2010	$	
2011		
2012		700

2013		250
2014		
Thereafter		3,200
Total (1)	$	4,150

(1) Excludes aggregate unamortized net discount of $14 million and an adjustment of $1 million related to a fair value hedge.

Note 5 Partners Capital and Distributions

Units Outstanding

Partners capital at December 31, 2009 consists of 136,135,988 common units outstanding, representing a 98% effective aggregate ownership interest in the Partnership and its subsidiaries after giving effect to the 2% general partner interest.

Distributions

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

General Partner Incentive Distributions

Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, the

Table of Contents

general partner is typically entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per unit, referred to as our minimum quarterly distributions (MQD), 25% of the amounts we distribute in excess of $0.495 per unit and 50% of amounts we distribute in excess of $0.675 per unit (referred to as incentive distributions).

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

	Year 2009		2008		2007	
	Distribution (1)	Excess over MQD	Distribution (1)	Excess over MQD	Distribution (1)	Excess over MQD
First Quarter	$ 0.8925	$ 0.4425	$ 0.8500	$ 0.4000	$ 0.8000	$ 0.3500
Second Quarter	$ 0.9050	$ 0.4550	$ 0.8650	$ 0.4150	$ 0.8125	$ 0.3625
Third Quarter	$ 0.9050	$ 0.4550	$ 0.8875	$ 0.4375	$ 0.8300	$ 0.3800
Fourth Quarter	$ 0.9200	$ 0.4700	$ 0.8925	$ 0.4425	$ 0.8400	$ 0.3900

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

In order to enhance our distribution coverage ratio and liquidity following a significant acquisition, our general partner may agree to reduce the amounts due to it as incentive distributions. Upon closing of the Pacific acquisition in November 2006 and the Rainbow acquisition in May 2008, our general partner agreed to reduce the amounts due to it as incentive distributions. Additionally, in connection with the PNGS Acquisition, our general partner agreed to further reduce its incentive distributions by an aggregate of $8 million over the next two years $1.25 million per quarter for the first four quarters and $0.75 million per quarter for the next four quarters. This incentive distribution reduction became effective upon payment of our November 2009 quarterly distribution of $0.9200 per limited partner unit. The total reduction in incentive distributions related to the Pacific, Rainbow and PNGS acquisitions is $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 2010 (as discussed below), the aggregate remaining incentive distribution reductions will be approximately $18 million.

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

	Common	Distributions Paid General Partner	Distributions per limited partner

Year	Units	Incentive	2%	Total	unit
2009	$ 468	$ 127	$ 10	$ 605	$ 3.62
2008	$ 418	$ 106	$ 8	$ 532	$ 3.50
2007	$ 370	$ 73	$ 8	$ 451	$ 3.28

On January 20, 2010, we declared a cash distribution of $0.9275 per unit on our outstanding common units. The distribution was paid on February 12, 2010 to unitholders of record on February 2, 2010, for the period October 1, 2009 through December 31, 2009. The total distribution paid was approximately $166 million, with approximately $126 million paid to our common unitholders and $3 million and $37 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Noncontrolling Interest in a Subsidiary

During the fourth quarter of 2008, we completed construction on a 94-mile expansion of the Salt Lake City Area system from Wahsatch, Utah to Salt Lake City. During the first quarter of 2009, this pipeline became fully operational.

Table of Contents

Pursuant to a master formation agreement, we contributed the pipeline with a book value of approximately $254 million to a newly formed joint venture, SLC Pipeline LLC (SLC Pipeline). Holly Energy Partners-Operating, L.P. (HEP) contributed approximately $26 million in cash for a 25% ownership in SLC Pipeline. We own the remaining 75% interest in SLC Pipeline and control the joint venture, and therefore, have consolidated the financial results. We recognized a loss in partners capital of approximately $38 million related to the formation of the SLC Pipeline joint venture during 2009. This loss represents the difference between HEP s contribution of cash and the book value of its 25% interest in the net assets of SLC Pipeline. As of December 31, 2009, the noncontrolling interest on the balance sheet consists solely of HEP s interest in the net assets of SLC Pipeline.

Equity Offerings

During the three years ended December 31, 2009, we completed the following equity offerings of our common units (in millions, except unit and per unit data):

Period	Units Issued		Gross Unit Price		Proceeds from Sale		General Partner Contribution		Costs		Net Proceeds
September 2009 (1)	5,290,000	$	46.70	$	247	$	5	$	(6)	$	246
March 2009 (1)	5,750,000		36.90		212		4		(6)		210
2009 Total	**11,040,000**			**$**	**459**	**$**	**9**	**$**	**(12)**	**$**	**456**
May 2008 (1)	6,900,000	$	46.31	$	320	$	6	$	(11)	$	315
2008 Total	**6,900,000**			**$**	**320**	**$**	**6**	**$**	**(11)**	**$**	**315**
June 2007 (2)	6,296,172	$	59.56	$	375	$	8	$		$	383
2007 Total	**6,296,172**			**$**	**375**	**$**	**8**	**$**		**$**	**383**

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

(2) This offering was a direct placement of common units, did not involve underwriters and did not require a gross spread. However, the gross unit price includes the discount to market required to execute this transaction. The net proceeds of this offering were used (i) to fund expansion capital programs; (ii) to fund the acquisition of the Bumstead LPG storage business, which we acquired in 2007 for approximately $52 million; (iii) to repay indebtedness under our senior unsecured credit facility; and (iv) for general partnership purposes.

PNGS Acquisition

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

Class B Units of Plains AAP, L.P.

In August 2007, the owners of Plains AAP, L.P. authorized the board of directors of Plains All American GP LLC to issue grants of Class B units of Plains AAP, L.P. (Class B units). At December 31, 2009, grants of approximately 165,500 Class B units were outstanding, of which 38,500 were earned. A total of 34,500 Class B units are reserved for future issuances. See Note 10 for further discussion of Class B units.

Table of Contents

Canadian Withholding Tax

For federal income tax purposes, we are treated as a partnership. Our unitholders are required to report their share of our income, gains, losses and deductions on their federal income tax return. In certain cases, we are subject to, and have paid, Canadian income and withholding taxes. The withholding tax payments are considered to be paid on behalf of our unitholders and thus are treated as distributions for financial reporting purposes. During 2009, we paid approximately $6 million of Canadian withholding taxes.

Note 6 Derivatives and Hedging Instruments

We identify the risks that underlie our core business activities and utilize risk management strategies to mitigate those risks when we determine that there is value in doing so. We use various derivative instruments to (i) manage our exposure to commodity price risk as well as to optimize our profits, (ii) manage our exposure to interest rate risk and (iii) manage our exposure to currency exchange-rate risk. Our policy is to use derivative instruments only for risk management purposes. Our commodity 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. Our interest rate and foreign currency risk management policies and procedures are designed to monitor our positions and ensure that those positions are consistent with our objectives and approved strategies. Our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategies for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument s effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives used in a transaction are highly effective in offsetting changes in cash flows or the fair value of hedged items. A discussion of our derivative activities by risk category follows.

Commodity Price Risk Hedging

Our core business activities contain certain commodity price-related risks that we manage in various ways, including the use of derivative instruments. Our policy is (i) to 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 earn, 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 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 that occur within each month. In connection with our efforts 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 relative to the volumes originally scheduled for such month, based on interim information. The purpose of these purchases and sales is to manage risk as opposed to establishing a risk position. 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 material commodity related risks inherent in our business activities can be summarized into the following general categories:

Commodity Purchases and Sales In the normal course of our supply and logistics operations, we purchase and sell crude oil, LPG, and refined products. We use derivatives to manage the associated risks and to optimize profits. As of December 31, 2009, material net derivative positions related to these activities included:

- An approximate 173,900 barrel per day net long position (total of 5.2 million barrels) associated with our crude oil activities, which was unwound ratably during January 2010 to match monthly average pricing.

- An approximate 17,500 barrel per day (total of 13.1 million barrels) net short spread position which hedge a portion of our anticipated crude oil lease gathering purchases through January 2012. These derivatives protect our margin on future floating price crude oil purchase commitments. These derivatives in the aggregate do not result in exposure to outright price movements.

- A net short spread position averaging approximately 8,300 barrels per day (total of 6 million barrels) of calendar spread call options for the period February 2010 through January 2012. These derivatives in the aggregate do not result in exposure to outright price movements.

- An average of approximately 4,200 barrels per day (total of 1.1 million barrels) of butane/West Texas Intermediate (WTI) spread positions, which hedge specific butane sales contracts that are priced as a fixed percentage of WTI and

Table of Contents

continue through September 2010.

- Approximately 18,500 barrels per day on average (total of 6.7 million barrels) of crude oil basis differential hedges through December 2010.

- An approximate 5,600 barrels per day (total of 0.5 million barrels) of propane swaps to hedge committed sales of propane inventory through March 2010.

Storage Capacity Utilization We own approximately 57 million barrels of crude oil, LPG and refined products storage capacity that is not used in our transportation operations. This storage may be leased to third parties or utilized in our own supply and logistics activities, including for the storage of inventory in a contango market. For capacity allocated to our supply and logistics operations we have utilization risk if the market structure is backwardated. As of December 31, 2009, we used derivatives to manage the risk of not utilizing approximately 3 million barrels per month of storage capacity through 2011. These positions are a combination of calendar spread options and NYMEX futures contracts. These positions involve no outright price exposure, but instead represent potential offsetting purchases and sales between time periods (first month versus second month for example).

Inventory Storage At times, we elect to purchase and store crude oil, LPG and refined products inventory in conjunction with our supply and logistics activities. These activities primarily relate to the seasonal storage of LPG inventories and contango market storage activities. When we purchase and store barrels, we enter into physical sales contracts or use derivatives to mitigate price risk associated with the inventory. As of December 31, 2009, we had approximately 8.2 million barrels of inventory hedged with derivatives.

We also purchase foreign cargoes of crude oil and may enter into derivatives to mitigate various price risks associated with the purchase and ultimate sale of foreign crude inventory. As of December 31, 2009, we had approximately 2.6 million barrels of crude oil derivatives hedging the anticipated sale of foreign crude inventory and 2.2 million barrels of crude oil spread positions hedging the anticipated purchase of foreign crude inventory.

Pipeline Loss Allowance Oil As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We utilize derivative instruments to hedge a portion of the anticipated sales of the allowance oil that is to be collected under our tariffs. As of December 31, 2009, we had entered into a net short position consisting of crude oil futures and swaps to manage the risk associated with the anticipated sale of an average of approximately 2,300 barrels per day (total of 2.4 million barrels) from January 2010 through December 2012. In addition, we had a long put option position of approximately 1 million barrels through December 2012 and a net long call option position of approximately 2 million barrels through December 2011, which provide upside price participation.

Diluent Purchases We use diluent in our Canadian crude oil pipeline operations and have used derivative instruments to hedge the anticipated forward purchases of diluent and diluent inventory. As of December 31, 2009, we had an average of 2,400 barrels per day of natural gasoline/WTI spread positions (approximately 1.3 million barrels) that run through mid-2011 and an average of 3,300 barrels per day of short crude oil futures (approximately 0.6 million barrels) to hedge condensate through the second quarter of 2010.

Natural Gas Purchases Our gas storage facilities require minimum levels of natural gas (base gas) to operate. For our natural gas storage facilities that are under construction, we anticipate purchasing base gas in future periods as construction is completed. We use derivatives to hedge anticipated purchases of natural gas. As of December 31, 2009, we have a net long position of approximately 3 Bcf consisting of natural gas futures contracts through August 2010.

The derivative instruments we use 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. Over-the-counter transactions include commodity swap and option contracts. All of our commodity derivatives that qualify for hedge accounting are designated as cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred into AOCI and recognized in revenues or purchases and related costs in the periods during which the underlying physical transactions occur. We have determined that substantially all of our physical purchase and sale agreements qualify for the normal purchase and normal sale (NPNS) exclusion and thus are not subject to the accounting treatment for derivative instruments and hedging activities as set forth in FASB guidance. Physical commodity contracts that meet the definition of a derivative but are ineligible, or not designated, for the NPNS scope exception are recorded on the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues.

Table of Contents

Interest Rate Risk Hedging

We use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and in certain cases, outstanding debt instruments. The derivative instruments we use to manage this risk consist primarily of interest rate swaps and treasury locks. As of December 31, 2009, AOCI includes deferred losses of $8 million that relate to terminated interest rate swaps and treasury locks that were designated for hedge accounting. These terminated interest rate derivatives were cash settled in connection with the issuance and refinancing of debt agreements. The deferred loss related to these instruments is being amortized to interest expense over the original terms of the forecasted debt instruments.

As of December 31, 2009, we had four outstanding interest rate swaps by which we receive fixed interest payments and pay floating-rate interest payments based on three-month LIBOR plus an average spread of 2.42% on a semi-annual basis. The swaps have an aggregate notional amount of $300 million with fixed rates of 4.25%. Two of the swaps terminate in 2011 and two of the swaps terminate in 2012.

Currency Exchange Rate Risk Hedging

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 primarily include forward exchange contracts and foreign currency forwards and options. As of December 31, 2009, AOCI includes net deferred gains of $15 million that relate to open and settled forward exchange contracts that were designated for hedge accounting. These forward exchange contracts hedge the cash flow variability associated with CAD-denominated interest payments on a CAD-denominated intercompany note as a result of changes in the foreign exchange rate.

As of December 31, 2009, our outstanding foreign currency derivatives also include derivatives used to hedge CAD-denominated crude oil purchases and sales. We may from time to time hedge the commodity price risk associated with a CAD-denominated commodity transaction with a USD-denominated commodity derivative. In conjunction with entering into the commodity derivative we enter into a foreign currency derivative to hedge the resulting foreign currency risk. These foreign currency derivatives are generally short-term in nature and are not designated for hedge accounting.

At December 31, 2009, our open foreign exchange derivatives included forward exchange contracts that exchange CAD for USD on a net basis as follows (in millions):

		CAD		USD	Average Exchange Rate
2010	$	43	$	39	CAD $1.14 to USD $1.00
2011	$	15	$	15	CAD $1.01 to USD $1.00
2012	$	15	$	15	CAD $1.01 to USD $1.00
2013	$	9	$	9	CAD $1.00 to USD $1.00

These financial instruments are placed with large, highly rated financial institutions.

Summary of Financial Impact

The majority of our derivative activity is related to our commodity price risk hedging activities. All of our commodity derivatives that qualify for hedge accounting are designated as cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred to AOCI and recognized in earnings in the periods during which the underlying physical transactions impact earnings. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of the hedged items, are recognized in earnings each period. Cash settlements associated with our derivative activities are reflected as operating cash flows in our consolidated statements of cash flows.

A summary of the impact of our derivative activities recognized in earnings for the twelve months ended December 31, 2009 is as follows (in millions, losses designated in parentheses):

Table of Contents

Year Ended December 31, 2009

	Location of gain/(loss)	Derivatives in Cash Flow Hedging Relationships AOCI Reclass (1)	Derivatives in Cash Flow Hedging Relationships Ineffective Portion (2)	Derivatives Not Designated as a Hedge (3)	Total
Commodity contracts	Supply and Logistics segment revenues	$ (90)	$ (8)	$ (10)	$ (108)
	Transportation segment revenues	4			4
	Facilities segment revenues	(1)			(1)
	Purchases and related costs	69		122	191
Interest Rate Contracts	Other income, net			(1)	(1)
	Interest expense	(1)		3	2
Foreign Exchange Contracts	Supply and Logistics segment revenues			7	7
	Purchases and related costs	1		3	4
	Other income, net	10		(7)	3
Total Gain/(Loss) on Derivatives Recognized in Income		**$ (8)**	**$ (8)**	**$ 117**	**$ 101**

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

(2) Amounts represent the ineffective portion of the fair value of our cash flow hedges that were recognized in earnings during the period.

(3) Includes realized and unrealized gains or losses for derivatives that are not designated for hedge accounting during the period.

The following table summarizes the derivative assets and liabilities on our consolidated balance sheet as of December 31, 2009 (in millions):

Table of Contents

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location		**Fair Value**	**Balance Sheet Location**		**Fair Value**
Derivatives designated as hedging instruments:						
Commodity contracts	Other current assets	$	153	Other current liabilities	$	(140)
	Other long-term assets		34	Other long-term liabilities		(1)
Interest rate contracts	Other current assets			Other current liabilities		
	Other long-term assets			Other long-term liabilities		
Foreign exchange contracts	Other current assets			Other current liabilities		
	Other long-term assets		2	Other long-term liabilities		
Total derivatives designated as hedging instruments		$	189		$	(141)
Derivatives not designated as hedging instruments:						
Commodity contracts	Other current assets	$	34	Other current liabilities	$	(91)
	Other long-term assets		41	Other long-term liabilities		(34)
Interest rate contracts	Other current assets		1	Other current liabilities		
	Other long-term assets		1	Other long-term liabilities		
Foreign exchange contracts	Other current assets		2	Other current liabilities		(3)
	Other long-term assets			Other long-term liabilities		
Total derivatives not designated as hedging instruments		$	79		$	(128)
Total derivatives		$	268		$	(269)

As of December 31, 2009, there was a net gain of $18 million deferred in AOCI. The total amount of deferred net gain recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the earnings recognition of the underlying hedged physical transaction, (ii) interest expense accruals associated with underlying debt instruments or (iii) the recognition of a foreign currency gain or loss upon the remeasurement of certain CAD-denominated intercompany interest receivables. Of the total net gain deferred in AOCI at December 31, 2009, a net loss of approximately $25 million is expected to be reclassified to earnings in the next twelve months. Of the remaining deferred gain in AOCI, approximately 96% is expected to be reclassified to earnings prior to 2013 with the remaining deferred gain being reclassified to earnings through 2019. These amounts are predominately based on market prices at the current period end, thus actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

During the year ended December 31, 2009, we reclassed a deferred gain of approximately $5 million from AOCI to other income as a result of anticipated hedge transactions that are no longer considered to be probable of occurring. During the year ended December 31, 2008, no amounts were reclassed from AOCI as a result of anticipated hedge transactions that were no longer considered to be probable of occurring.

Amounts of loss recognized in AOCI on derivatives (effective portion) during the year ended December 31, 2009 are as follows (in millions):

		For the Year Ended December 31, 2009
Commodity contracts	$	(145)
Foreign exchange contracts		(4)
Interest rate contracts		(2)
Total	$	(151)

We do not enter into master netting agreements with our over-the-counter derivative counterparties, nor do we offset the assets and liabilities associated with the fair value of our derivatives with amounts we have recognized related to our right to receive or our obligation to pay cash collateral. When we deposit cash collateral with our brokers, we recognize a broker receivable, which is a component of our accounts receivable. The account equity in our brokerage accounts is a combination of our cash balance and the fair value of our open derivatives within our brokerage account. When our account equity is less

Table of Contents

than our initial margin requirement we are required to post margin. Our broker receivable was approximately $53 million and $81 million as of December 31, 2009 and 2008, respectively. At December 31, 2009 and December 31, 2008, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment which does affect the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value as of December 31, 2009 (in millions)				Fair Value as of December 31, 2008 (in millions)			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets:								
Commodity derivatives	$ 251	$	$ 11	$ 262	$ 235	$ 9	$ 112	$ 356
Interest rate derivatives			2	2			5	5
Foreign currency derivatives			4	4			18	18
Total assets at fair value	$ 251	$	$ 17	$ 268	$ 235	$ 9	$ 135	$ 379
Liabilities:								
Commodity derivatives	$ (224)	$	$ (42)	$ (266)	$ (330)	$	$ (56)	$ (386)
Foreign currency derivatives			(3)	(3)			(5)	(5)
Total liabilities at fair value	$ (224)	$	$ (45)	$ (269)	$ (330)	$	$ (61)	$ (391)
Net asset/(liability) at fair value	$ 27	$	$ (28)	$ (1)	$ (95)	$ 9	$ 74	$ (12)

The determination of the fair values above include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit) but also the impact of our nonperformance risk on our liabilities. The fair value of our commodity derivatives, interest-rate derivatives and foreign currency derivatives includes adjustments for credit risk. We measure credit risk by deriving a probability of default from market observed credit default swap spreads as of the measurement date. The probability of default is applied to the net credit exposure of each of our counterparties and includes a recovery rate adjustment. The recovery rate is an estimate of what would ultimately be recovered through a bankruptcy proceeding in the event of default. There were no changes to any of our valuation techniques during the period.

Level 1

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

Level 2

Included within level 2 of the fair value hierarchy as of December 31, 2008 is a physical commodity supply contract that meets the definition of a derivative but does not qualify for the NPNS scope exception as set forth in FASB guidance. The fair value of this commodity derivative is measured with level 1 inputs for similar but not identical instruments and therefore must be included in level 2 of the fair value hierarchy.

Level 3

Included within level 3 of the fair value hierarchy are the following derivatives:

- Commodity Derivatives: Level 3 commodity derivatives include over-the-counter commodity derivatives such as forwards, swaps and options and certain physical commodity contracts. The fair value of our level 3 commodity derivatives is based on either an indicative broker or dealer price quotation or a valuation model.

Table of Contents

Our valuation models utilize inputs such as price, volatility and correlation and do not involve significant management judgments.

- Interest Rate Derivatives: Level 3 interest rate derivatives include interest rate swaps. The fair value of our interest rate derivatives is based on indicative broker or dealer price quotations. Broker or dealer price quotations are corroborated with objective inputs including forward LIBOR curves and forward Treasury yields that are obtained from pricing services.

- Foreign Currency Derivatives: Level 3 foreign currency derivatives include foreign currency swaps, forward exchange contracts and options. The fair value of our foreign currency derivatives is based on indicative broker or dealer price quotations. Broker or dealer price quotations are corroborated with objective inputs including forward CAD/USD forward exchange rates that are obtained from pricing services.

The majority of our level 3 derivatives are classified as such because the broker or dealer price quotations used to measure fair value and the pricing services used to corroborate the quotations are indicative quotations rather than quotations whereby the broker or dealer is ready and willing to transact. However, the fair value of these level 3 derivatives is not based upon significant management assumptions or subjective inputs.

Rollforward of Level 3 Net Liability

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

	Year Ended December 31,	
	2009	**2008**
Beginning Balance	$ 74	$ (21)
Unrealized gains/(losses):		
Included in earnings (1)	46	68
Included in other comprehensive income	(43)	35
Settlements and derivatives entered into during the period	(105)	(8)
Ending Balance	$ (28)	$ 74
Change in unrealized gains/(losses) included in earnings relating to level 3 derivatives still held at the end of the periods	$ 31	$ 44

(1) Unrealized gains and losses associated with level 3 commodity derivatives are reported in our consolidated statements of operations as supply and logistics segment revenues. Gains and losses associated with interest rate derivatives are reported in our consolidated statements of operations as either other income, net or interest expense. Gains and losses associated with foreign currency derivatives are reported in our consolidated statements of operations as either supply and logistics segment revenues, purchases and related costs, or other income, net.

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

Note 7 Income Taxes

U.S. Federal and State Taxes

As a master limited partnership, we are not subject to U.S. federal income taxes; rather the tax effect of our operations is passed through to our unitholders. Although, we are subject to state income taxes in some states, the impact to the years ended December 31, 2009, 2008 and 2007 was immaterial.

Canadian Federal and Provincial Taxes

Certain of our Canadian subsidiaries are corporations for Canadian tax purposes, thus their operations are subject to Canadian federal and provincial income taxes. The remainder of our Canadian operations is conducted through an operating limited partnership, which has historically been treated as a flow-through entity for tax purposes. This entity is subject to Canadian legislation passed in June 2007 that imposes entity-level taxes on certain types of flow-through entities. This legislation includes safe harbor guidelines that grandfather certain existing entities (which, we believe, would include us) and delays the effective date of such legislation until 2011.

Table of Contents

Additionally, in December 2008, the Fifth Protocol to the U.S./Canada Tax Treaty was ratified and contained language that increases the withholding tax on dividends and intercompany interest effective in 2010. As a result of these collective changes, we are in the process of reviewing our Canadian structure.

Tax Components

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

	Year Ended December 31, 2009	2008	2007
Current tax expense:			
State income tax	$ 2	$ 1	$ 1
Canadian federal and provincial income tax	13	8	2
Total current tax expense	$ 15	$ 9	$ 3
Deferred tax (benefit)/expense:			
State income tax	$	$	$ 1
Canadian federal and provincial income tax	(9)	(1)	12
Total deferred tax (benefit)/expense	$ (9)	$ (1)	$ 13
Total income tax expense	$ 6	$ 8	$ 16

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

	Year Ended December 31, 2009	2008	2007
Income before tax	$ 586	$ 445	$ 381
Partnership earnings not subject to current Canadian tax	(585)	(422)	(369)
	$ 1	$ 23	$ 12
Canadian federal and provincial corporate tax rate	29.0%	29.5%	32.1%
Income tax at statutory rate	$	$ 7	$ 4
Current tax expense:			
Canadian period tax as a result of book versus tax differences	4	4	(2)
Canadian permanent differences between book and tax	9	(3)	
State income tax	2	1	1
Current income tax expense	$ 15	$ 9	$ 3
Deferred tax expense:			
State deferred income tax			1
Canadian deferred tax (benefit)/expense as a result of book versus tax differences	(4)	(4)	2
Canadian flow-through entities deferred tax (benefit)/expense as a result of book versus tax differences	(5)	3	10
Deferred income tax (benefit)/expense	$ (9)	$ (1)	$ 13
Total income tax expense	$ 6	$ 8	$ 16

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

Table of Contents

	December 31, 2009	December 31, 2008
Deferred tax assets:		
Book accruals in excess of current tax deductions	$ 13	$ 9
Total deferred tax assets	13	9
Deferred tax liabilities:		
Property, plant and equipment in excess of tax values	(134)	(118)
Total deferred tax liabilities	(134)	(118)
Net deferred tax liabilities	$ (121)	$ (109)

Generally, tax returns for our Canadian entities are open to audit from 2005 through 2009. Our U.S. and state tax years are open to examination from 2006 to 2009.

Note 8 Major Customers and Concentration of Credit Risk

Marathon Petroleum Company, LLC accounted for 14%, 14% and 19% of our revenues for each of the three years ended December 31, 2009, 2008 and 2007, respectively. Valero Marketing & Supply Company accounted for 10% of our revenues for the year ended December 31, 2007. ConocoPhillips Company accounted for 12%, 12% and 11% of our revenues for the years ended December 31, 2009, 2008 and 2007, respectively. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2009. The majority of revenues from these customers pertain to our supply and logistics operations. We believe that the loss of these customers would have only a short-term impact on our operating results. There is risk, however, that we would not be able to identify and access a replacement market at comparable margins.

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

Table of Contents

Note 9 Related Party Transactions

Reimbursement of Expenses of Our General Partner and its Affiliates

We do not pay our general partner a management fee, but we do reimburse our general partner for all direct and indirect costs of services provided to us or incurred on our behalf, including the costs of employee, officer and director compensation and benefits allocable to us as well as all other expenses necessary or appropriate to the conduct of our business (other than expenses related to grants of Class B units). We record these costs on the accrual basis in the period in which our general partner incurs them. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion. Total costs reimbursed by us to our general partner for the years ended December 31, 2009, 2008 and 2007 were $328 million, $289 million and $287 million, respectively.

Vulcan Energy Corporation

As of December 31, 2009, Vulcan Energy Corporation (Vulcan Energy) and its affiliates owned approximately 50% of our general partner interest, as well as approximately 9% of our outstanding limited partner units.

Voting Agreement. In August 2005, Vulcan Energy s ownership interest in our general partner increased from 44% to over 50%. At the closing of the transaction, Vulcan Energy entered into a voting agreement that restricts its ability to unilaterally elect or remove our independent directors, and separately, our CEO and COO agreed, subject to certain ongoing conditions, to waive certain change-of-control payment rights that would otherwise have been triggered by the increase in Vulcan Energy s ownership interest. These ownership changes to our general partner had no material impact on us.

Another owner of Plains All American GP LLC, Lynx Holdings I, LLC, agreed to restrict certain of its voting rights with respect to its approximate 1.4% membership interest in Plains All American GP LLC.

Administrative Services Agreement. On October 14, 2005, Plains All American GP LLC (GP LLC) and Vulcan Energy entered into an Administrative Services Agreement, effective as of September 1, 2005 (the Services Agreement). Pursuant to the Services Agreement, GP LLC provides administrative services to Vulcan Energy for consideration of an annual fee, plus certain expenses. Effective October 1, 2006, the annual fee for providing these services was increased to $1 million. Beginning in October 2008, the Services Agreement automatically renews for successive one-year periods unless either party provides written notice of its intention to terminate the Services Agreement. Pursuant to the agreement, Vulcan Energy has appointed certain employees of GP LLC as officers of Vulcan Energy for administrative efficiency. Under the Services Agreement, Vulcan Energy acknowledges that conflicts may arise between itself and GP LLC. If GP LLC believes that a specific service is in conflict with the best interest of GP LLC or its affiliates then GP LLC is entitled to suspend the provision of that service and such a suspension will not constitute a breach of the Services Agreement.

Omnibus Agreement. PAA, GP LLC, certain affiliated entities and Vulcan Energy are parties to an amended and restated omnibus agreement dated as of July 23, 2004. Pursuant to this agreement, Vulcan Energy has agreed, so long as Vulcan Energy or any of its affiliates owns an interest, directly or indirectly, in GP LLC, not to engage in or acquire any business engaged in the following activities:

- crude oil storage, terminalling and gathering activities in any state in the United States (except for Hawaii), the Outer Continental Shelf of the United States or any province or territory in Canada, for any person other than entities affiliated with Vulcan Energy and its affiliates (collectively, the Vulcan entities) or GP LLC, PAA, its operating partnerships and any controlled affiliates (collectively, the Plains entities);

Table of Contents

- crude oil marketing activities; and
- transportation of crude oil by pipeline in any state in the United States (except for Hawaii), the Outer Continental Shelf of the United States or any province or territory in Canada, for any person other than the Plains entities.

These restrictions are subject to specified permitted exceptions and may be terminated by Vulcan Energy upon certain change of control events involving Vulcan Energy. The omnibus agreement further permits, except as otherwise restricted by the omnibus agreement or any other agreement, each Vulcan entity to engage in any business activity, including those that may be in direct competition with the Plains entities. Further, any owner of equity interests in Vulcan Energy may make passive investments in PAA s competitors so long as such owner does not directly or indirectly use any knowledge or confidential information it received through the ownership by a Plains entity to compete, or to engage in or become interested financially in any person that competes, in the restricted activities described above.

Crude Oil Purchases. From August 2005 to May 2007, Calumet Florida L.L.C (Calumet) was owned by Vulcan Resources Florida, Inc., the majority of which is owned by Paul G. Allen. In May 2007, Calumet was sold and ceased to be related to Vulcan Energy. In 2007, until the date that Calumet ceased to be related to Vulcan Energy, we purchased crude oil from Calumet for approximately $17 million.

Investment in PAA/Vulcan Gas Storage, LLC

In September 2005, we and Vulcan Gas Storage LLC, a subsidiary of Vulcan LLC, an investment arm of Paul G. Allen, formed PAA/Vulcan Gas Storage, LLC to acquire ECI (now known as PAA Natural Gas Storage, LLC or PNGS), an indirect subsidiary of Sempra Energy, for approximately $250 million. We and Vulcan Gas Storage each made an initial cash investment of approximately $113 million and Bluewater Natural Gas Storage, LLC, a subsidiary of PAA/Vulcan, entered into a $90 million credit facility contemporaneously with closing.

From September 2005 until September 3, 2009, we owned 50% of PAA/Vulcan and Vulcan Gas Storage LLC owned the other 50%. Giving effect to all contributions and distributions made during the period from January 1, 2007 through September 3, 2009, we and Vulcan Gas Storage each made a net contribution of $39 million. Such contributions and distributions did not result in an increase or decrease to our ownership interest.

On September 3, 2009, one of our subsidiaries acquired the remaining 50% interest in PAA/Vulcan from Vulcan Gas Storage LLC, which resulted in our ownership of a 100% interest in PNGS. See Note 3 for further discussion of the PNGS Acquisition.

Table of Contents

Note 10 Equity Compensation Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the 1998 Plan), the 2005 Long-Term Incentive Plan (the 2005 Plan) and the PPX Successor Long-Term Incentive Plan (the PPX Successor Plan) for employees and directors as well as the Plains All American GP LLC 2006 Long- Term Incentive Tracking Unit Plan (the 2006 Plan) for non-officer employees. The 1998 Plan, 2005 Plan and PPX Successor Plan authorize the grant of an aggregate of 5.4 million common units deliverable upon vesting. Although other types of awards are contemplated under the plans, currently outstanding awards are limited to phantom units, which mature into the right to receive common units (or cash equivalent) upon vesting. Some awards also include distribution equivalent rights (DERs). Subject to applicable earning criteria, a DER entitles the grantee to a cash payment equal to the cash distribution paid on an outstanding common unit. The 2006 Plan authorizes the grant of approximately 1.6 million tracking units which, upon vesting, represent the right to receive a cash payment in an amount based upon the market value of a common unit at the time of vesting. Our general partner is entitled to reimbursement by us for any costs incurred in settling obligations under the plans.

In accordance with FASB guidance regarding share-based payments, the fair value of our LTIP awards, which are subject to liability classification, is calculated based on the closing market price of our units at each balance sheet date adjusted for (i) the present value of any distributions that are estimated to occur on the underlying units over the vesting period that will not be received by the award recipients and (ii) an estimated forfeiture rate when appropriate. This fair value is recognized as compensation expense over the period the awards are earned. Our LTIP awards typically contain performance conditions based on attainment of certain annualized distribution levels and vest upon the later of a certain date or the attainment of such levels. For awards with performance conditions, we recognize compensation expense only if the achievement of the performance condition is considered probable and we amortize that expense over the service period. When awards with performance conditions that were previously considered improbable of occurring become probable of occurring, we incur additional LTIP compensation expense necessary to adjust the life-to-date accrued liability associated with these awards. Our DER awards typically contain performance conditions based on the attainment of certain annualized distribution levels and become earned upon the attainment of such levels. The DERs terminate with the vesting or forfeiture of the underlying LTIP award. We recognize compensation expense for DER payments in the period the payment is earned.

At December 31, 2009 , the following LTIP awards were outstanding (units in millions):

LTIP Units Outstanding	Vesting Distribution Amount	Estimated Unit Vesting Date			
		2010	2011	2012	2013
0.6**(1)**	$3.20	0.6			
1.5**(2)**	$3.50 - $4.50		0.5	0.8	0.1
1.8**(3)**	$3.50 - $4.25	0.5	0.3	0.8	0.2
3.9**(4) (5)**		1.1	0.8	1.6	0.3

(1) Upon our February 2007 annualized distribution of $3.20, these LTIP awards satisfied all distribution requirements and will vest upon completion of the respective service period.

(2) These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between $3.50 and $4.50 and vest upon the later of a certain date or the attainment of such levels. If the performance conditions are not attained while the grantee remains employed by us, or the grantee does not meet employment requirements, these awards will be forfeited. For purposes of this disclosure, the awards are presented above based on an estimate of future distribution levels and assuming that all grantees remain employed by

us through the vesting date.