PLAINS ALL AMERICAN PIPELINE LP
Form 10-K
February 25, 2015
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, 2014

or

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

Commission file number 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

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

Registrant s telephone number, including area code: **(713) 646-4100**

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o

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

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

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

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

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

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

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

The aggregate market value of the Common Units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Common Units outstanding, for this purpose, as if they may be affiliates of the registrant) was approximately $21.8 billion on June 30, 2014, based on a closing price of $60.05 per Common Unit as reported on the New York Stock Exchange on such date.

As of February 18, 2015, there were 376,241,697 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

NONE

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

FORM 10-K 2014 ANNUAL REPORT

Table of Contents

		Page
	PART I	4
Items 1 and 2.	Business and Properties	4
Item 1A.	Risk Factors	46
Item 1B.	Unresolved Staff Comments	63
Item 3.	Legal Proceedings	63
Item 4.	Mine Safety Disclosures	64
	PART II	65
Item 5.	Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities	65
Item 6.	Selected Financial Data	67
Item 7.	Management s Discussion and Analysis of Financial Condition and Results of Operations	69
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	96
Item 8.	Financial Statements and Supplementary Data	97
Item 9.	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	97
Item 9A.	Controls and Procedures	98
Item 9B.	Other Information	98
	PART III	99
Item 10.	Directors and Executive Officers of Our General Partner and Corporate Governance	99
Item 11.	Executive Compensation	113
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters	132
Item 13.	Certain Relationships and Related Transactions, and Director Independence	135
Item 14.	Principal Accountant Fees and Services	139
	PART IV	140
Item 15.	Exhibits and Financial Statement Schedules	140

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 such words, expressions or statements, however, does not mean that the statements are not forward-looking. Any such forward-looking 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 or outcomes to differ materially from the results or outcomes anticipated in the forward-looking statements. The most important of these factors include, but are not limited to:

- failure to implement or capitalize, or delays in implementing or capitalizing, on planned growth projects;

- declines in the volume of crude oil, refined product and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our facilities, whether due to declines in production from existing oil and gas reserves, failure to develop or slowdown in the development of additional oil and gas reserves, whether from reduced cash flow to fund drilling or the inability to access capital, or other factors;

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

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

- 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 effects of competition;

- the occurrence of a natural disaster, catastrophe, terrorist attack or other event, including attacks on our electronic and computer systems;

- tightened capital markets or other factors that increase our cost of capital or limit 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;

- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;

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

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

- the currency exchange rate of the Canadian dollar;

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

- the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;

- the effectiveness of our risk management activities;

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

- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements, and related interpretations;

- non-utilization of our assets and facilities;

- increased costs, or lack of availability, of insurance;

Table of Contents

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

- risks related to the development and operation of our facilities, including our ability to satisfy our contractual obligations to our customers at our facilities;

- factors affecting demand for natural gas and natural gas storage services and rates;

- general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns; and

- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the storage of natural gas and the processing, transportation, fractionation, storage and marketing of natural gas liquids.

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

PART I

Items 1 and 2. *Business and Properties*

General

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

We own and operate midstream energy infrastructure and provide logistics services for crude oil, natural gas liquids (NGL), natural gas and refined products. The term NGL includes ethane and natural gasoline products as well as products commonly referred to as liquefied petroleum gas (LPG) such as propane and butane. We own an extensive network of pipeline transportation, terminalling, storage, and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. Our business activities are conducted through three operating segments: Transportation, Facilities and Supply and Logistics.

Organizational History

We were formed as a master limited partnership to acquire and operate the midstream crude oil businesses and assets of a predecessor entity and completed our initial public offering in 1998. Our 2% general partner interest is held by PAA GP LLC, a Delaware limited liability company, whose sole member is Plains AAP, L.P., a Delaware limited partnership (AAP). AAP also owns all of our incentive distribution rights (IDRs). As of December 31, 2014, Plains GP Holdings, L.P. (PAGP), a Delaware limited partnership that completed its initial public offering in October 2013 and that has elected to be treated as a corporation for U.S. federal income tax purposes, owned a 34.1% limited partner interest in AAP (a 31.8% economic interest), and the remaining limited partner interests in AAP were held by the owners of our general partner entities immediately prior to PAGP s initial public offering. Plains All American GP LLC, a Delaware limited liability company (GP LLC), is AAP s general partner. PAGP is the sole member of GP LLC, and PAA GP Holdings LLC is the general partner of PAGP. References to our general partner, as the context requires, include any or all of PAA GP LLC, AAP and GP LLC.

Table of Contents

Partnership Structure and Management

Our operations are conducted directly and indirectly through, and our operating assets are owned by, our subsidiaries. GP LLC has responsibility for conducting our business and managing our operations; however, PAGP effectively controls our business and affairs through the exercise of its rights as the sole and managing member of our general partner, including its right to appoint certain members to the board of directors of our general partner. 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 AAP which are referred to herein as the AAP Management Units).

The two charts below show the structure and ownership of PAA and its subsidiaries as of December 31, 2014 in both a summarized and more detailed format. The first chart depicts PAA s legal structure in summary format, while the second chart depicts a more comprehensive view of PAA s legal structure, including ownership and economic interests and shares and units outstanding.

Summarized Partnership Structure

(as of December 31, 2014)

(1) Board appointment rights limited to non-management investors that own greater than 10% interest in AAP.

Table of Contents

Detailed Partnership Structure

(as of December 31, 2014)

Table of Contents

---

(1) 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 IDRs.

(2) The Partnership holds direct and indirect ownership interests in consolidated operating subsidiaries including, but not limited to, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Midstream Canada ULC (PMC).

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

(4) Represents the number of Class A units of AAP (AAP units) for which the AAP Management Units would be exchangeable, assuming a conversion rate of approximately 0.925 AAP units for each AAP Management Unit as of December 31, 2014. The AAP Management Units are entitled to certain proportionate distributions paid by AAP.

(5) As of December 31, 2014, PAGP owned 34.1% of the membership interests in its general partner, which percentage corresponds to its ownership percentage of AAP units (34.1%, representing a 31.8% economic interest in AAP, including the dilutive effect of the AAP Management Units).

Business Strategy

Our principal business strategy is to provide competitive and efficient midstream transportation, terminalling, storage, processing, fractionation and supply and logistics services to producers, refiners and other customers. Toward this end, we endeavor to address regional supply and demand imbalances for crude oil and NGL in the United States and Canada by combining the strategic location and capabilities of our transportation, terminalling, storage, processing and fractionation assets with our extensive supply, logistics and distribution expertise. We believe successful execution of this strategy will enable us to generate sustainable earnings and cash flow. We intend to manage and grow our business by:

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

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

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

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

To a lesser extent, we also engage in similar activities for natural gas and refined products.

Competitive Strengths

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

- *Many of our 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 crude oil producing regions and other transportation corridors and are connected, directly or indirectly, with our facilities segment assets. The majority of our facilities segment assets are located at major trading locations and premium markets that serve as gateways to major North American refinery and distribution markets where we have strong business relationships. In addition, our assets include pipeline, rail, barge, truck and storage assets, which provide our customers and us with significant flexibility and optionality to satisfy demand and balance markets, particularly during a dynamic period of changing product flows.

Table of Contents

• *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 (including our knowledge of North American crude oil flows), provide us with an extensive understanding of the North American physical crude oil markets.

• *Our supply and logistics activities typically generate a base level of margin with the opportunity to realize incremental margins.* We believe the variety of activities executed within our supply and logistics segment in combination with our risk management strategies provides us with a balance that generally affords us the flexibility to maintain a base level of margin in a variety of market conditions (subject to the effects of seasonality). In certain circumstances, we are able to realize incremental margins during volatile market conditions.

• *We have the evaluation, integration and engineering skill sets and the financial flexibility to continue to pursue acquisition and expansion opportunities.* Since 1998, we have completed and integrated over 80 acquisitions with an aggregate purchase price of approximately $11.6 billion. We have also implemented expansion capital projects totaling over $7.8 billion. In addition, considering our investment grade credit rating, liquidity and capital structure, we believe we have the financial resources and strength necessary to finance future strategic expansion and acquisition opportunities. As of December 31, 2014, we had approximately $2.6 billion of liquidity available, including cash and cash equivalents and availability 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 30 years industry experience, and an average of 18 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 AAP Management Units, our management team has a vested interest in our continued success.

Financial Strategy

Targeted Credit Profile

We believe that a major factor in our continued success is our ability to maintain a competitive cost of capital and access to the capital markets. In that regard, we intend to maintain a credit profile that we believe is consistent with investment grade credit ratings. We have targeted a general credit profile with the following attributes:

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

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

- an average total debt-to-total capitalization ratio of approximately 60%; and
- an average adjusted EBITDA-to-interest coverage multiple of approximately 3.3x or better.

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

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

Table of Contents

Acquisitions

The acquisition of midstream assets and businesses that are strategic and complementary to our existing operations constitutes an integral component of our business strategy and growth objectives. Such assets and businesses include crude oil, refined products and NGL logistics assets, natural gas storage assets and other energy assets that have characteristics and provide opportunities similar to our existing business lines and enable us to leverage our assets, knowledge and skill sets.

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

Acquisition (1)	Date	Description	Approximate Purchase Price (2)	
50% Interest in BridgeTex Pipeline Company, LLC (BridgeTex)	Nov-2014	BridgeTex owns a crude oil pipeline that extends from Colorado City, Texas to East Houston	$	1,088(3)
US Development Group (USD) Crude Oil Rail Terminals	Dec-2012	Four operating crude oil rail terminals and one terminal under development	$	503
BP Canada Energy Company (BP NGL)	Apr-2012	NGL assets located in Canada and the upper-Midwest United States	$	1,683(4)
Western Refining, Inc. (Western) Pipeline and Storage Assets	Dec-2011	Multi-product storage facility in Virginia and Crude oil pipeline in southeastern New Mexico	$	220(5)
Velocity South Texas Gathering, LLC (Velocity)	Nov-2011	Crude oil and condensate gathering and transportation assets in South Texas (Gardendale Gathering System)	$	349
SG Resources Mississippi, LLC (SG Resources)	Feb-2011	Southern Pines Energy Center (Southern Pines) natural gas storage facility	$	765(6)
Nexen Holdings U.S.A. Inc. Gathering and Transportation Assets (Nexen)	Dec-2010	Crude oil gathering business and transportation assets in North Dakota and Montana	$	229(7)

---

(1) Excludes our acquisition of all of the outstanding publicly-traded common units of PAA Natural Gas Storage, L.P. (PNG) on December 31, 2013 (referred to herein as the PNG Merger), as we historically consolidated PNG into our financial statements for financial reporting purposes in accordance with generally accepted accounting principles in the United States (GAAP). As consideration for the PNG Merger, we issued approximately 14.7 million PAA common units with a value of approximately $760 million. See Note 11 to our Consolidated Financial Statements for further discussion of the PNG Merger.

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

(3) Approximate purchase price of $1.075 billion, net of working capital acquired. We account for our 50% interest in BridgeTex under the equity method of accounting.

(4) Purchase price includes approximately $17 million of imputed interest. A prepayment of $50 million was made during 2011. Approximate purchase price of $1.192 billion, net of working capital, linefill and long-term inventory acquired.

(5) Includes two transactions with Western.

(6) Approximate purchase price of $750 million, net of cash and other working capital acquired.

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

Ongoing Acquisition and Investment Activities

Consistent with our business strategy, we are continuously engaged in the evaluation of potential acquisitions, joint ventures and capital projects. As a part of these efforts, we often engage in discussions with potential sellers or other parties regarding the possible purchase of or investment in assets and operations that are strategic and complementary to our existing operations. In addition, we have in the past evaluated and pursued, and intend in the future to evaluate and pursue, the acquisition of or investment in other energy-related assets that have characteristics and provide opportunities similar to our existing business lines and enable us to leverage our assets, knowledge and skill sets. Such efforts may involve participation by us in processes that have been made public and involve a number of potential buyers or investors, 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 parties who are in negotiations with the potential seller or other party. These acquisition and investment efforts often involve assets which, if acquired or constructed, could have a material effect on our financial condition and results of operations.

Table of Contents

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

Expansion Capital Projects

Our extensive asset base and our relationships with customers provide us with opportunities for organic growth through the construction of additional assets that are complementary to, and expand or extend, our existing asset base. We believe that the diversity and balance of our expansion capital project portfolio (i.e., relatively large number of projects that are small to medium sized and spread across multiple geographic regions) reduces our overall exposure to cost overruns, timing delays and other adverse market developments with respect to a particular project or region. Our 2015 expansion capital plan is representative of the diversity and balance of our overall project portfolio. The following expansion capital projects are included in our 2015 capital plan as of February 2015:

Basin/Region	Project	2015 Plan Amount (1) ($ in millions)	Description	Projected In-Service Date
Permian	Permian Basin Area Projects	$ 365	Multiple projects to increase and expand our pipeline infrastructure in the Permian Basin, including expansion of trunklines into the Delaware Basin and corresponding looping of the Wink-to-Midland segment of our Basin Pipeline	Various, throughout 2015 and 2016
	Cactus Pipeline	85	310 miles of new crude oil pipeline; 250,000 Bbls/d capacity (to be expanded to 330,000 Bbls/d in 2016) from the Permian Basin to the Eagle Ford Pipeline	2015
Eagle Ford	Eagle Ford JV Project	85	55 miles of new gathering and trunkline pipeline to connect Karnes and Live Oak County production areas to the Three Rivers, TX terminal; 70 miles of new pipeline from Three Rivers to Corpus Christi, TX; expanded storage and pumping capacity at Three Rivers; Construction of new terminal on the Corpus Christi ship channel	Various, throughout 2015, 2016 and 2017
	Eagle Ford Area Projects	35	New condensate processing stabilizer with 40,000 Bbls/d of capacity; conversion of existing Gardendale, TX stabilizer into rich fuel gas use; installation of pumps, metering and 10 miles of pipeline enabling delivery of NGL out of our Gardendale processing plant	2015
	Diamond Pipeline	165		2017

Central / Mid-Continent			440 miles of new crude oil pipeline; 200,000 Bbls/d capacity from Cushing, OK to the Valero Memphis, TN refinery	
	Red River Pipeline	80	Approximately 400 miles of new crude oil pipeline; 150,000 Bbls/d capacity from Cushing, OK to Longview, TX	2016
	Cushing Terminal Expansions	25	Addition of 1.4 million barrels of storage capacity	2015
Rocky Mountain	Cowboy Pipeline	50	27 miles of new crude oil pipeline; 65,000 Bbls/d capacity from Cheyenne, WY to our rail loading facility near Carr, CO; construction of new terminal at Cheyenne	2015

Table of Contents

West Coast	Line 63 Reactivation		30	Reactivation of 71 miles of idled pipeline and supporting assets	2015
Canada	Fort Saskatchewan Facility Projects / NGL Line		290	Multi-phase project, Phase I of which includes (i) development of two new high rate delivery caverns, (ii) conversion of service of two existing caverns, (iii) the addition of 2.5 million barrels of brine capacity and (iv) development of a truck loading facility Phase II includes (i) expanding inlet fractionation capacity by 20,000 Bbls/d, (ii) development of two new ethane caverns and a utility cavern, (iii) the addition of 2.65 million barrels of brine capacity and (iv) development of a propane rail loading facility	Various, throughout 2015, 2016 and 2017
Other	Rail Terminal Projects		240	Railcar purchases and projects located in or near St. James, LA and Kerrobert, Canada	2015
	Other Projects		400		
		$	1,850		

(1) Represents the portion of the total project cost expected to be incurred during the year. Potential variation to current capital costs estimates may result from (i) changes to project design, (ii) final cost of materials and labor and (iii) timing of incurrence of costs due to uncontrollable factors such as permits, regulatory approvals and weather.

Global Petroleum Market Overview

Crude oil and NGL are two primary components of the world petroleum market, and world economic growth is a major driver of such market. The challenging global economic climate of the last several years resulted in continued uncertainty in the petroleum market. Over the last six months of 2014, global production growth outpaced global consumption growth resulting in lower energy prices. Currently, the United States and Canada comprise 5% of the world s population, generate approximately 20% of the world s petroleum production, and consume approximately 23% of the world s petroleum production. The table below depicts historical and projected production and consumption of liquid fuels for the United States and Canada and the rest of the world and is derived from the EIA Short-Term Energy Outlook, January 2015 (see EIA website at *www.eia.doe.gov*):

[redacted]

Production (Supply)							
U.S. & Canada	13.7	15.0	16.5	18.3	19.3	20.0	4.6
Rest of the World	74.2	74.8	73.7	73.8	73.7	73.5	(0.4)
Total (2)	87.9	89.8	90.2	92.2	93.0	93.5	4.3

[redacted]

Consumption (Demand)

U.S. & Canada	21.2	20.8	21.4	21.4	21.7	21.8	0.2
Rest of the World	67.3	68.3	69.1	70.0	70.7	71.6	2.7
Total (2)	88.5	89.1	90.5	91.4	92.4	93.4	2.9
U.S. & Canada Production as % of World Production (2)	16%	17%	18%	20%	21%	21%	4%
U.S. & Canada Consumption as % of World Consumption (2)	24%	23%	24%	23%	23%	23%	0%
Net U.S. & Canada (Consumption) (2)	(7.4)	(5.8)	(4.8)	(3.1)	(2.4)	(1.8)	4.4
Global Supply/Demand Balance	(0.6)	0.6	(0.3)	0.8	0.6	0.1	1.3

(1) The 2014 amounts are derived from the EIA s Short-Term Energy Outlook.

(2) Amounts may not recalculate due to rounding.

Table of Contents

For the period from 2011 through 2014, global liquids production increased 4.3 million barrels per day while global liquids consumption only increased 2.9 million barrels per day. U.S. and Canadian production growth of 4.6 million barrels per day during this period has not only offset a 0.4 million barrels per day decline in production for the rest of the world but also has supplied the 2.9 million barrels per day increase in global demand. This surge in liquids production without a commensurate increase in demand has led to a near to medium-term supply imbalance, which has further led to a reduction in benchmark petroleum prices. The lower prices are leading producers to scale back capital programs, which we believe should ultimately slow down the supply growth and contribute toward bringing the markets back to equilibrium.

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 oil grade has distinguishing physical properties. For example, specific gravity (generally referred to as light or heavy), sulfur content (generally referred to as sweet or sour) and metals content, along with other characteristics, collectively result in varying economic attributes. In many cases, these factors result in the need for such grades to be batched or segregated in the transportation and storage processes, blended to precise specifications or adjusted in value.

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

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

Over the last five years, one of the most significant developments impacting the crude oil market has been the rapid growth in North American crude oil production. As a result of advances in horizontal drilling and completion technology over the last several years and their application to various large scale resource plays, certain historical trends have been reversed as domestic crude oil supplies have increased substantially and have the potential to continue to increase if supported by crude oil prices. Increased production has come from both mature producing areas such as the Rockies, the Permian Basin in West Texas and the Mid-Continent region, as well as from less mature, but rapidly growing areas such as the Eagle Ford Shale in South Texas and the Bakken Shale in North Dakota. As a result, North American liquids production increased 4.6 million barrels per day or 34% between 2011 and 2014, with the increases coming primarily from Canada, the Eagle Ford Shale in South Texas, the Permian Basin in West Texas and the Bakken Shale in North Dakota. Actual and anticipated production increases in all of these regions have strained existing transportation, terminalling and downstream infrastructure. These changes have resulted in significant alterations to historical patterns of crude oil movements among regions of the U.S.

In addition to overall production growth, significant shifts in the type and location of crude oil being produced from these regions have resulted in additional strains on existing infrastructure. Notably, the increase in domestic production of light sweet crude oil is inconsistent with the sizeable, multi-year investments made by a number of U.S. refining companies in order to expand their capabilities to process heavier, sour grades of crude oil. This divergence between readily available supplies of light sweet crude oil and increased refinery demand for heavy sour crude oil has begun to cause differentials between crude oil grades and qualities to change relative to historical levels and become more dynamic and volatile. This increase in light sweet crude oil production has also resulted in a decrease in foreign imports of light sweet crude oil into the U.S., particularly into the Gulf Coast, which has caused the international producers of such lighter crudes to seek alternative markets in other parts of the world. These previously imported barrels have been absorbed by the rest of the world until recently, when total liquids supply began increasing faster than demand.

Table of Contents

Since reaching a multi-year low in 2009, U.S. net refinery inputs of crude oil have slowly increased to a level of 15.8 million barrels per day for the twelve month period ended November 2014, which approximates the levels achieved during 2005 and 2006. Although domestic demand for petroleum products from end users has declined from peak levels in 2004-2007 and the increased use of ethanol for blending in gasoline has further negatively impacted refinery demand for crude oil, the attractive export market for refined products and access to discounted domestic crude oil has driven the increased refinery demand. Domestic production growth has also led to lower use of imported crude oil by U.S. refineries, a meaningful change in a multi-year trend where foreign imports of crude oil tripled over an approximately 23-year period from 1985-2007. The EIA is currently forecasting a continued gradual decline in foreign crude imports from current levels, which is attributable to increased domestic production and increased supply from other liquid products, including ethanol and biodiesel.

The table below shows the overall domestic petroleum consumption projected through 2016 and is derived from the EIA Short-Term Energy Outlook, January 2015 (see EIA website at *www.eia.doe.gov*). We believe these trends will be subject to significant variation from time to time due to a number of factors, including the level of domestic production volumes and infrastructure limitations, which impact pricing, and geopolitical developments.

	Actual (1)	**Projected (1)**	
	2014	**2015**	**2016**
		(In millions of barrels per day)	
Supply			
Domestic Crude Oil Production	8.6	9.3	9.5
Net Imports - Crude Oil from Canada	3.2	3.4	3.4
Net Imports - Crude Oil from Other	3.8	3.0	2.9
Other (Supply Adjustment/Stock Change)	0.1	0.2	0.1
Crude Oil Input to Domestic Refineries	15.8	15.9	16.0
Net Product Imports / (Exports)	(1.9)	(2.2)	(2.4)
Supply from Renewable Sources	1.1	1.1	1.1
Other - (NGL Production, Refinery Processing Gain)	4.1	4.5	4.8
Total Domestic Petroleum Consumption	19.1	19.3	19.4

(1) Amounts may not recalculate due to rounding.

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

By way of illustration, the Department of Energy segregates the United States into five Petroleum Administration Defense Districts (PADDs), which are used by the energy industry for reporting statistics regarding crude oil supply and demand. The table below sets forth supply, demand and shortfall information for each PADD for the twelve months ended November 2014 and is derived from information published by the EIA (see EIA website at *www.eia.doe.gov*):

	Regional	**Refinery**	**Supply**

Petroleum Administration Defense District (in millions of barrels per day) (1)	Supply	Demand	Shortfall
PADD I (East Coast)	0.0	1.1	(1.0)
PADD II (Midwest)	1.7	3.5	(1.9)
PADD III (South)	5.1	8.2	(3.1)
PADD IV (Rockies)	0.6	0.6	0.0
PADD V (West Coast)	1.1	2.4	(1.3)
Total U.S.	8.6	15.8	(7.3)

(1) Amounts may not recalculate due to rounding.

Table of Contents

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

- continued development of North American resource plays;
- fluctuations in international supply and demand related to the economic environment, geopolitical events and armed conflicts;
- regional supply and demand imbalances and changes in refinery capacity and specific capabilities;
- significant fluctuations in absolute price as well as grade and location differentials;
- political instability in critical producing nations; and
- policy decisions made by various governments around the world attempting to navigate energy challenges.

The complexity and volatility of the crude oil market creates opportunities to solve the logistical inefficiencies inherent in the business. The combination of (i) a significant increase in North American production volumes, (ii) a change in crude oil qualities and related differentials and (iii) high utilization of existing pipeline and terminal infrastructure has stimulated multiple industry initiatives to build new pipeline and terminal infrastructure, convert certain pipeline assets to alternative service or reverse flows and expand the use of trucks, rail and barges for the movement of crude oil and condensate.

Processed Condensate Market

During 2014, the U.S. Department of Commerce, Bureau of Industry and Security (BIS) clarified that processed condensate may be eligible to export if certain criteria are met. In response to our request for clarification, the BIS issued a letter to us stating that the distillation processes employed by PAA at its Gardendale facility satisfies the conditions of the BIS to convert lease condensate into an exportable petroleum product. Per the EIA, lease condensate production (which the EIA generally defines as light liquid hydrocarbons recovered from lease separators or field facilities) has risen from 488,000 barrels per day in 2009 to 852,000 barrels per day in 2013 through the development of the domestic unconventional resource plays. Texas currently yields approximately one-half of the U.S. lease condensates per the EIA.

Refined Products Market Overview

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

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 or sent further downstream for additional processing in petrochemical or specialty chemical facilities. The majority of products are shipped by pipeline to storage terminals near consuming areas, and then loaded into trucks for delivery to gasoline stations and end users. Products that are used as feedstocks are typically transported by pipeline or barges to chemical plants.

Demand for refined products has generally been affected by price levels, economic growth trends, conservation, fuel efficiency mandates and, to a lesser extent, weather conditions. From 2011 through November 2014, petroleum consumption has remained relatively flat averaging approximately 18.8 million barrels per day. During this period, as production from domestic resource plays increased, less expensive alternative crude sources have provided domestic refineries with a competitive advantage. This has allowed refineries to increase crude runs from lows of 13.7 million barrels per day in February 2011 to highs of 16.5 million barrels per day in July 2014 with the incremental refined products produced primarily going to export markets. The increased domestic refinery runs combined with flat domestic demand has allowed the U.S. to become a net exporter of refined products versus a historical net importer. Refined product imports decreased from 3.2 million barrels per day in 2005 to an average of approximately 1.7 million barrels per day for the 12 months ended November 2014. Conversely, refined product exports increased from approximately 1.1 million barrels per day in 2005 to 3.1 million barrels per day for the 12 months ended November 2014.

Table of Contents

NGL Market Overview

NGL primarily includes ethane, propane, normal butane, iso-butane, and natural gasoline, and is derived from natural gas production and processing activities as well as crude oil refining processes. LPG primarily includes propane and butane, which liquefy at moderate pressures thus making it easier to transport and store such products as compared to ethane. NGL refers to all NGL products including LPG when used in this document.

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

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

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

- *Normal butane.* Normal butane is principally used for motor gasoline blending and as fuel gas, either alone or in a mixture with propane, and feedstock for the manufacture of ethylene and butadiene, a key ingredient of synthetic rubber. Normal butane is also used as a feedstock for iso-butane production and as a diluent in the transportation of heavy crude oil and bitumen, particularly in Canada.

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

- *Natural Gasoline.* Natural gasoline is principally used as a motor gasoline blend stock, a petrochemical feedstock, or as diluent in the transportation of heavy crude oil and bitumen, particularly in Canada.

NGL Supply. The bulk (approximately 78%) of the United States NGL supply comes from gas processing plants, which separate a mixture of NGL from the dry gas (primarily methane). The NGL mix (also referred to as Y Grade) is then either fractionated at the processing site into the five individual NGL components (known as purity products), which may be transported, stored and sold to end use markets or transported as a Y-Grade to a regional fractionation facility.

The majority of gas processing plants in the United States are located along the Gulf Coast, in the West Texas/Oklahoma area, the Marcellus and Utica region and in the Rockies region. In Canada, the vast majority of the processing capacity is located in Alberta, with a much smaller (but increasing) amount in British Columbia and Saskatchewan.

NGL products from refineries represent approximately 18% of the United States supply and are by-products of the refinery conversion processes. Consequently, they have generally already been separated into individual components and do not require further fractionation. NGL products from refineries are principally propane, with lesser amounts of butane, refinery naphthas (products similar to natural gasoline) and ethane. Due to refinery maintenance schedules and seasonal demand considerations, refinery production of propane and butane varies on a seasonal basis.

NGL is also imported into certain regions of the United States from Canada and other parts of the world (approximately 4% of total supply). NGL (primarily propane) is also exported from certain regions of the United States.

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

The major NGL infrastructure and trading hubs in North America are located at Mont Belvieu, Texas; Conway, Kansas; Edmonton, Alberta; and Sarnia, Ontario. Each of these hubs contains a critical mass of infrastructure, including fractionators, storage, pipelines and access to end markets, particularly Mont Belvieu.

Table of Contents

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

NGL Market Outlook. The growth of shale based production in both traditional and new producing areas has resulted in a significant increase in NGL supplies from gas processing plants over the past several years. This has driven extensive expansion and new development of midstream infrastructure in Canada, the Bakken, Marcellus/Utica, and throughout Texas.

The growth of production in non-traditional producing regions has shifted regional basis relationships and the creation of new logistics and infrastructure opportunities. Growing NGL production has meant expansion into new markets, through exports or increased petrochemical demand. The continuation of a relatively low ratio of North American gas and NGL prices to world-wide crude oil prices will mean North American NGL can continue to be competitive on a world scale, either as feedstock for North American based manufacturing or export to overseas markets. In addition to substantially increased exports, a portion of the increased supply of NGL will be absorbed by the domestic petrochemical sector as low-cost feed stocks, as the North American petrochemical industry has enjoyed a supply cost advantage on a world scale.

While a short term price drop may stunt production growth, the fundamentals of an accessible resource base and improved midstream infrastructure should mean producers can continue to develop the most economic new supply and be ready to go back to rapid growth as prices recover. The NGL market is, among other things, expected to be driven by:

- the absolute prices of NGL products and their prices relative to natural gas and crude oil;
- drilling activity and wet natural gas production in developing liquids-rich production areas;
- production growth/decline rates of wet natural gas in established supply areas;
- available processing, fractionation, storage and transportation capacity;
- infrastructure development costs and timing as well as development risk sharing;
- the cost of acquiring rights from producers to process their gas;

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

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

Table of Contents

Natural Gas Storage Market Overview

North American natural gas storage facilities provide a staging and warehousing function for seasonal swings in demand relative to supply, as well as an essential reliability cushion against disruptions in natural gas supply, demand and transportation by allowing natural gas to be injected into, withdrawn from or warehoused in such storage facilities as dictated by market conditions. Natural gas storage serves as the shock absorber that balances the market, serving as a source of supply to meet the consumption demands in excess of daily production capacity and a warehouse for gas production in excess of daily demand during low demand periods.

Overall market conditions for natural gas storage have been challenging during the last several years, driven by a variety of factors, including (i) increased natural gas supplies due to production from shale resources, (ii) a shift from Gulf of Mexico production to Northeast production causing less concern over disruptions from tropical weather, (iii) increased availability of storage capacity, (iv) a reduction in overall market depth due to various companies exiting the physical gas marketing business and (v) lower basis differentials in certain regions due to expansion and improved connectivity of natural gas transportation infrastructure over the last five years.

Longer term, we believe several factors will contribute to meaningful growth in North American natural gas demand that will bolster the market need for and the commercial value of natural gas storage. These fundamental factors include (i) exports of North American volumes of LNG, (ii) construction of new gas-fired power plants, (iii) sustained fuel switching from coal to natural gas among existing power plants and (iv) growth in base-level industrial demand. As a result, we remain optimistic about the intermediate- to long-term intrinsic value of our natural gas storage assets.

Projected seasonal spreads for the next few years reflect a directionally similar picture to the challenging market conditions we have experienced during most of the past few years. Continuation of these unfavorable market conditions will adversely impact our hub services activities as well as the rates our customers are willing to pay for firm storage services with respect to new capacity under construction and existing capacity upon expirations of existing storage agreements.

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 pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. The map below highlights our more significant assets (including certain assets under construction or development) as of December 31, 2014:

Table of Contents

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

Transportation Segment

Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and NGL on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third-party pipeline capacity agreements and other transportation fees. Our transportation segment also includes equity earnings from our investments in Settoon Towing and the White Cliffs, Eagle Ford, BridgeTex, Butte and Frontier pipeline systems, in which we own interests ranging from 22% to 50%. We account for these investments under the equity method of accounting.

As of December 31, 2014, we employed a variety of owned or, to a much lesser extent, leased long-term physical assets throughout the United States and Canada in this segment, including approximately:

- 17,800 miles of active crude oil and NGL pipelines and gathering systems;
- 29 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;
- 800 trailers (primarily in Canada); and
- 149 transport and storage barges and 72 transport tugs through our interest in Settoon Towing.

Table of Contents

The following is a tabular presentation of our active crude oil and NGL pipeline assets in the United States and Canada as of December 31, 2014, grouped by geographic location:

Region / Pipeline and Gathering Systems (1)	System Miles	2014 Average Net Barrels per Day (2) (in thousands)
United States Crude Oil Pipelines		
Permian Basin		
Basin / Mesa / Sunrise	682	733
BridgeTex (3)	408	14
Permian Basin Area Systems	2,838	765
Permian Basin Subtotal	3,928	1,512
South Texas/Eagle Ford		
Eagle Ford Area Systems	470	227
Western		
All American	138	37
Line 63 / Line 2000	342	122
Other	122	101
Western Subtotal	602	260
Rocky Mountain		
Bakken Area Systems	1,025	149
Salt Lake City Area Systems	969	136
White Cliffs (3)	1,054	30
Other	1,304	111
Rocky Mountain Subtotal	4,352	426
Gulf Coast		
Capline (3)	631	152
Other	915	340
Gulf Coast Subtotal	1,546	492
Central		
Mid-Continent Area Systems	2,345	348
Other	280	102
Central Subtotal	2,625	450
United States Total	**13,523**	**3,367**
Canada		
Crude Oil Pipelines:		
Manito	561	47
Rainbow	842	112
Rangeland	1,233	65
South Saskatchewan	346	62
Other	198	113
Crude Oil Pipelines Subtotal	3,180	399
NGL Pipelines:		
Co-Ed	632	58
Other	430	128

NGL Pipelines Subtotal	1,062	186
Canada Total	**4,242**	**585**
Grand Total	**17,765**	**3,952**

Table of Contents

---

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

(2) Represents average volume for the entire year attributable to our interest. Volumes associated with assets employed through acquisitions or expansion capital represent total volumes (attributable to our interest) for the number of days we employed the assets divided by the number of days in the year.

(3) Pipelines operated by a third party.

United States Pipelines

Permian Basin

Basin Pipeline System. We own an 87% undivided joint interest in and are the operator of the Basin pipeline system. The Basin system is a primary route for transporting crude oil from the Permian Basin (in west Texas and southern New Mexico) to Cushing, Oklahoma, for further delivery to Mid-Continent and Midwest refining centers. The Basin system also serves as the initial movement for transporting crude oil from the Permian Basin to the Gulf Coast through connections to other carriers at Colorado City, Texas and Wichita Falls, Texas. The Basin system accommodates three primary movements of crude oil: (i) barrels that are shipped from Jal, New Mexico to the West Texas markets of Wink/Hendrick and Midland; (ii) barrels that are shipped from Midland to connecting carriers at Colorado City or Wichita Falls; and (iii) barrels that are shipped from Jal, Midland, Colorado City and Wichita Falls to connecting carriers at Cushing.

The Basin system is an approximate 520-mile mainline, telescoping crude oil system with a system capacity ranging from approximately 240,000 barrels per day to 450,000 barrels per day (approximately 208,800 barrels per day to 392,000 barrels per day attributable to our interest) depending on the segment. System throughput (as measured by tariff volumes) was 498,000 barrels per day (attributable to our interest) during 2014. Throughput volumes are measured at different points across the 520-mile pipeline and barrels can enter and leave the system moving through a short or long segment. The Basin system is subject to tariff rates regulated by the Federal Energy Regulatory Commission (FERC).The system also includes approximately 6 million barrels of tankage.

In 2014, we completed a project to increase capacity on the segment from Jal to Wink/Hendrick from approximately 144,000 barrels per day to 240,000 barrels per day (approximately 125,000 barrels per day to 208,800 barrels per day attributable to our interest). We are currently constructing an extension of the Basin system, which will include looping the Wink to Midland segment of the system. This project is expected to be complete in 2015.

Mesa Pipeline System. We own a 63% undivided interest in and are the operator of the Mesa pipeline system, which transports crude oil from Midland to a refinery at Big Spring, Texas and to connecting carriers at Colorado City. The Mesa system is an 80-mile mainline with a system capacity of up to 400,000 barrels per day (approximately 252,000 barrels per day attributable to our interest). System throughput (as measured by tariff volumes) was 227,000 barrels per day (attributable to our interest) during 2014.

Sunrise Pipeline. We own and operate the Sunrise pipeline system, which extends from Midland to connecting carriers at Colorado City, Texas. Construction of this 82-mile crude oil pipeline was completed during 2014. The Sunrise pipeline was placed in service in December 2014, with an initial capacity of 250,000 barrels per day.

BridgeTex Pipeline. In November 2014, we acquired a 50% interest in BridgeTex, which is the entity that owns the BridgeTex pipeline, a newly constructed 20-inch crude oil pipeline with a capacity of 300,000 barrels per day that extends 408 miles from Colorado City in West Texas to East Houston. At Colorado City, the BridgeTex pipeline is connected to our Basin and Sunrise pipeline systems. Magellan Midstream Partners, L.P. (MMP) owns the remaining 50% interest in BridgeTex and serves as the operator of the BridgeTex pipeline. BridgeTex has entered into a long term capacity lease agreement with MMP whereby its shippers will have access to capacity on the Texas City Leg, the section of the pipeline system that runs from Houston to Texas City, and the related Houston area refinery complex.

Permian Basin Area Systems. We operate wholly owned systems of 2,838 miles that aggregate receipts from wellhead gathering lines and bulk truck injection locations into a combination of 4- to 16-inch diameter trunk lines for transportation and delivery into the Basin system at Jal, Wink and Midland as well as our terminal facilities in Midland. During 2014, we completed construction of several projects servicing the South Spraberry area, including a new 20-inch, 62-mile crude oil pipeline with up to 200,000 barrels of takeaway capacity from the South Midland Basin to source crude oil to the Longhorn pipeline at Crane. This line will also connect to our Cactus pipeline at McCamey when the Cactus pipeline is placed into service in 2015. For 2014, combined throughput on the Permian Basin area systems totaled an average of 765,000 barrels per day.

Table of Contents

In 2013 and 2014, we announced several new projects to increase and expand our Permian Basin infrastructure over the next few years to support expected crude oil production growth. In January 2015, we placed into service 40 miles of pipeline with 100,000 barrels per day of pipeline capacity from Monahans to Crane, Texas to supply volumes to the Longhorn pipeline as well as our Cactus pipeline when it is placed into service in 2015. Our Cactus pipeline will be a new 310-mile crude oil pipeline extending from McCamey to Gardendale, Texas and is expected to initially provide approximately 250,000 barrels per day of additional takeaway capacity from the Permian Basin. Pumping equipment will be added in 2016, which will bring the total capacity of the pipeline to approximately 330,000 barrels per day. The remainder of our projects in the area are expected to be completed in stages throughout 2015 and 2016. See Expansion Capital Projects for additional information.

South Texas/Eagle Ford Area

Eagle Ford Area Systems. We own a 100% interest in and are the operator of several gathering systems that feed into our Gardendale Station, and we also own a 50% interest in and are the operator of the Eagle Ford joint venture pipeline. These Eagle Ford Area Systems consist of 470 miles of pipeline that service increasing production in the Eagle Ford shale play of South Texas and include approximately 2 million barrels of operational storage capacity across the system. The system serves the Three Rivers and Corpus Christi, Texas refineries and other markets via marine terminal facilities at Corpus Christi, as well as the Houston market via Enterprise Products Partners L.P. s (Enterprise) connection at Lyssy in Wilson County, Texas. For 2014, total average throughput on our Eagle Ford Area Systems was 227,000 barrels per day (attributable to our interest).

In 2013, we and Enterprise announced an expansion of the Eagle Ford joint venture pipeline. This project will increase the pipeline s capacity to 470,000 barrels per day by constructing a new 20-inch pipeline between Gardendale (where it will connect to our Cactus pipeline) and Three Rivers, Texas. This expansion also includes the construction of an additional 2 million barrels of operational storage capacity across the system. Additionally, in 2014 we announced the construction of a 70 mile, 20-inch pipeline from Three Rivers to Corpus Christi, and the expansion of pumping capabilities at Three Rivers. Combined, these projects will loop the entire Eagle Ford joint venture pipeline from Gardendale to Corpus Christi, and increase the total system capacity to over 600,000 barrels per day. These expansions are supported by long term production commitments. These projects are expected to be completed in 2015. See Expansion Capital Projects for additional information.

In 2014, Plains and Enterprise announced a project to construct a new condensate gathering system with approximately 55 miles of gathering and trunkline pipeline that will connect Karnes County and Live Oak County production areas to the Three Rivers, Texas terminal. Included in the gathering system will be over 500,000 barrels of operational storage at Three Rivers. This construction is expected to be completed in 2015. See Expansion Capital Projects for additional information.

Western

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

A portion of our transportation segment profit on Line 63 and Line 2000 is derived from the pipeline transportation business associated with the Santa Ynez and Point Arguello fields and fields located in the San Joaquin Valley. Volumes shipped from the OCS are expected to decline.

Line 63. We own and operate the Line 63 system. The Line 63 system is an intrastate common carrier crude oil pipeline system that transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. The Line 63 system consists of a 144-mile trunk pipeline, 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 five miles of distribution pipelines in the Los Angeles Basin, with a throughput capacity of approximately 144,000 barrels per day, and approximately 140 miles of gathering pipelines in the San Joaquin Valley, with an average throughput capacity of approximately 72,000 barrels per day. We also have approximately 1 million barrels of storage capacity on this system. These storage assets are used primarily to facilitate the transportation of crude oil on the Line 63 system. For 2014, combined throughput on Line 63 totaled an average of 48,000 barrels per day.

Table of Contents

During 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. We have commenced a project to place this idle segment into service, which we expect to complete in 2015. In December 2014, we commenced receipts on Line 63 of crude oil from our rail terminal at Bakersfield.

Line 2000. We own and operate 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 an approximately 130-mile, 20-inch trunk pipeline with a throughput capacity of approximately 130,000 barrels per day. During 2014, throughput on Line 2000 (excluding Line 63 volumes) averaged 74,000 barrels per day.

Rocky Mountain

Bakken Area Systems. We own and operate several gathering systems and pipelines that service crude oil production in Eastern Montana and Western North Dakota, and we also own a 22% interest in the Butte pipeline. These Bakken Area systems consist of 1,025 miles of pipeline, with total average throughput for 2014 of 149,000 barrels per day.

Salt Lake City Area Systems. We operate the Salt Lake City and Wahsatch pipeline systems, in which we own interests of between 75% and 100%. These systems include interstate and intrastate common carrier crude oil pipeline systems that transport crude oil produced in the U.S. Rocky Mountain region and Canada to refiners in Salt Lake City, Utah and to other pipelines at Ft. Laramie, Wyoming. These pipeline systems consist of 680 miles of pipelines and approximately one million barrels of storage capacity. These systems have a maximum throughput capacity of (i) approximately 20,000 barrels per day from Wamsutter, Wyoming to Ft. Laramie, Wyoming, (ii) approximately 49,000 barrels per day from Wamsutter, Wyoming to Wahsatch, Utah and (iii) approximately 120,000 barrels per day from Wahsatch, Utah to Salt Lake City, Utah. For 2014, throughput on these systems (excluding Frontier Pipeline) in total averaged 128,000 barrels per day.

Also included in the Salt Lake City Area systems is our 22% interest in Frontier pipeline, an interstate common carrier crude oil pipeline that consists of a 289-mile trunk pipeline with a maximum throughput capacity of 79,000 barrels per day. Frontier pipeline originates in Casper, Wyoming and delivers crude oil into the Wahsatch Pipeline System. For 2014, throughput on Frontier averaged 8,000 barrels per day (attributable to our interest).

White Cliffs Pipeline. We own an approximate 36% interest in the White Cliffs pipeline, a 12-inch common carrier, crude oil pipeline that originates in Platteville, Colorado and terminates in Cushing, Oklahoma. Rose Rock Midstream, L.P. serves as the operator of the pipeline. For 2014, throughput on White Cliffs pipeline averaged approximately 30,000 barrels per day (attributable to our interest). In August 2014, a White Cliffs pipeline expansion project that increased total system capacity from 76,000 barrels per day to 150,000 barrels per day was completed.

Cowboy Pipeline. We are currently developing the Cowboy pipeline, a 12-inch, 27-mile pipeline that will provide 65,000 barrels per day of capacity from Cheyenne, Wyoming to our rail loading facility near Carr, Colorado. The Cowboy pipeline project includes construction of a new terminal at Cheyenne with approximately 600,000 barrels of tank capacity for pipeline operation and storage. See Expansion Capital Projects for additional information.

Gulf Coast

Capline Pipeline System. The Capline pipeline system, in which we own an aggregate undivided joint interest of approximately 54%, is a 631-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. Marathon Pipeline LLC serves as the operator of the pipeline. Capline has direct connections to a significant amount of crude production in the Gulf of Mexico. In addition, it has two active docks capable of handling approximately 600,000-barrel tankers and is connected to the Louisiana Offshore Oil Port and our St. James terminal and transports various grades of crude oil to PADD II. Total designed operating capacity is approximately 1.1 million barrels per day of crude oil, of which our attributable interest is approximately 600,000 barrels per day. Throughput on our interest averaged 152,000 barrels per day during 2014.

In the fourth quarter of 2014, the Capline owners (including us) announced that the owner group is conducting a study to evaluate alternatives for the Capline pipeline system given the decreasing demand for South to North crude oil movements in North America. The study is expected to be completed in early 2015. Any change in the service offered by Capline would require the approval of all three owners, and there can be no assurance that the study will identify any actionable alternatives or that any alternative identified in the study will be pursued.

Pascagoula Pipeline. We own and operate the Pascagoula pipeline, a 41-mile crude oil pipeline that was placed in service in April 2014. The Pascagoula pipeline originates at our Ten Mile facility in Alabama and extends to a refinery on the Gulf Coast. Additionally, we have approximately 1.2 million barrels of storage capacity at our Ten Mile facility that supports the operational needs of this pipeline system. Throughput on the system averaged 79,000 barrels per day during 2014.

Table of Contents

Central

Mid-Continent Area Systems. We own and operate pipeline systems that source crude oil from the Cleveland Sand, Granite Wash and Mississippian/Lime resource plays of Western and Central Oklahoma, Southwest Kansas and the eastern Texas Panhandle. These systems consist of 2,345 miles of pipeline with transportation and delivery into and out of our terminal facilities at Cushing. For 2014, combined throughput on the Mid-Continent Area systems totaled an average of 348,000 barrels per day.

In 2014, we completed construction of a 113-mile extension of our existing Oklahoma crude oil pipeline and associated gathering system to service increasing production from producing areas in Western Oklahoma and the Texas Panhandle. This new Western Oklahoma pipeline provides up to 75,000 barrels per day of new takeaway capacity from Reydon, Oklahoma to our existing Orion station in Major County, Oklahoma.

Included in the Mid-Continent Area systems is our Mississippian Lime pipeline, which was placed into service in August 2013 to service crude oil production in Northern Oklahoma and Southern Kansas and to provide crude oil transportation to our terminal facilities at Cushing. During 2014, we completed two extensions of the Mississippian Lime pipeline. Throughput on the Mississippian Lime pipeline averaged 71,000 barrels per day during 2014.

We are currently developing the Diamond pipeline, a 20-inch, 440-mile long pipeline that will provide 200,000 barrels per day of capacity from our Cushing, Oklahoma terminal to the Valero Memphis, Tennessee refinery. The Diamond pipeline project is underpinned by a long term shipper agreement with Valero and a related contract for storage and terminalling services at our Cushing terminal. We expect to complete the Diamond pipeline in 2017. Valero holds an option until January 2016 to become a partner in the Diamond pipeline and purchase a 50 percent interest.

Also under development is the Red River pipeline, which will be a 16-inch pipeline with a takeaway capacity of 150,000 barrels per day extending from Cushing, Oklahoma to Longview, Texas. The Red River pipeline is supported by long term shipper commitments and is expected to be completed in 2016. See Expansion Capital Projects for additional information regarding our Mid-Continent area pipeline projects.

Canada Pipelines

Crude Oil Pipelines

Manito. We own a 100% interest in the Manito heavy oil system. This 561-mile system is comprised of the Manito pipeline, the North Saskatchewan (North Sask) pipeline and the Bodo/Cactus Lake pipeline. Each system consists of a blended crude oil line and a parallel diluent line that delivers condensate to upstream blending locations. The North Sask pipeline is 84 miles in length and originates near Turtleford, Saskatchewan and terminates in Dulwich, Saskatchewan. The Manito pipeline includes 339 miles of pipeline, and the mainline segment originates at Dulwich and terminates at Kerrobert, Saskatchewan. The Bodo/Cactus Lake pipeline is 138 miles long and originates in Bodo, Alberta and also terminates at our Kerrobert storage facility. The Kerrobert storage and terminalling facility is connected to the Enbridge pipeline system and can both receive and deliver heavy crude oil from and to the Enbridge pipeline system. For 2014, 47,000 barrels per day of crude oil were transported on the Manito system.

Rainbow System. We own a 100% interest in the Rainbow system. The Rainbow system is comprised of (i) a 480-mile, 20-inch to 24-inch mainline crude oil pipeline with a throughput capacity of approximately 220,000 barrels per day that extends from the Norman Wells Pipeline connection in Zama, Alberta to Edmonton, Alberta and has 174 miles of associated gathering pipelines and (ii) a 188-mile, 10-inch pipeline to transport diluent north from Edmonton, Alberta to our Nipisi truck terminal in Northern Alberta that has a capacity of 40,000 barrels per day. Total average throughput during 2014 on the Rainbow system was 112,000 barrels per day.

We are currently developing the Indigo pipeline, which will consist of two pipelines, a diluent line and a blend line, both approximately 80 miles in length. The diluent line will be a 12-inch pipeline that will transport diluent from our Rainbow system at Nipisi to the Peace River, Alberta area. The blend line will be a 24-inch pipeline that will deliver blended heavy crude oil from the Peace River, Alberta area to our Rainbow system. Construction is subject to regulatory approval, obtaining rights-of-way and satisfaction of other contractual provisions. The Indigo pipeline is underpinned by a long-term contract and is expected to be in service in 2017; however, the project may be delayed or terminated by the committed shipper based on certain completion dates and investment considerations, subject to full cost reimbursement to us.

Table of Contents

Rangeland System. We own a 100% interest in the Rangeland system. The Rangeland system consists of a 670 mile, 8-inch to 16-inch mainline pipeline and 563 miles of 3-inch to 8-inch gathering pipelines. The Rangeland system transports NGL mix, butane, condensate, light sweet crude oil and light sour crude oil either north to Edmonton, Alberta or south to the U.S./Canadian border near Cutbank, Montana, where it connects to our Western Corridor system. Total average throughput during 2014 on the Rangeland system was 65,000 barrels per day.

South Saskatchewan. We own a 100% interest in the South Saskatchewan system. This system consists of a 160 mile, 16-inch mainline from Cantuar to Regina, Saskatchewan and 186 miles of 4-inch to 12-inch gathering pipelines from the Rapdan area to Cantuar. The South Saskatchewan system transports heavy crude oil from gathering areas in southern Saskatchewan to Enbridge s mainline at Regina. Total average throughput during 2014 on the South Saskatchewan system was 63,000 barrels per day.

NGL Pipelines

Co-Ed NGL Pipeline System. We own and operate the Co-Ed NGL pipeline system, which consists of approximately 632 miles of 3-inch to 10-inch pipeline. This pipeline system gathers NGL from approximately 35 field gas processing plants located in Alberta, including all of the NGL produced at the Cochrane Straddle Plant. The Co-Ed NGL pipeline system has throughput capacity of approximately 72,000 barrels per day. During 2014, throughput averaged 58,000 barrels per day.

We are currently extending and expanding our Co-Ed NGL pipeline system. The projects consist of a North Co-Ed extension and a West Co-Ed expansion, which we expect to be completed in 2016 and 2017, respectively. The North Co-Ed extension will provide approximately 20 miles of bi-directional 12-inch high vapor pressure (HVP) NGL pipeline from our existing Co-Ed pipeline to our Fort Saskatchewan facilities with takeaway capacity of up to 110,000 barrels per day. The West Co-Ed expansion will provide an 8-inch, 18 mile NGL line from our Buck Creek facility to our Co-Ed pipeline at Breton, Alberta.

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, NGL and natural gas, as well as NGL fractionation and isomerization services and natural gas and condensate processing services. We generate revenue through a combination of month-to-month and multi-year agreements and processing arrangements. Revenues generated in this segment primarily include (i) fees that are generated from storage capacity agreements, (ii) terminal throughput fees that are generated when we receive crude oil, refined products or NGL from one connecting source and deliver the applicable product to another connecting carrier, (iii) loading and unloading fees at our rail terminals, (iv) fees from NGL fractionation and isomerization, (v) fees from natural gas and condensate processing services and (vi) fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing services.

As of December 31, 2014, we owned, operated or employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 73 million barrels of crude oil and refined products storage capacity primarily at our terminalling and storage locations;

- approximately 23 million barrels of NGL storage capacity;

- approximately 97 Bcf of natural gas storage working capacity;

- approximately 29 Bcf of owned base gas;

- 11 natural gas processing plants located throughout Canada and the Gulf Coast area of the United States;

- a condensate processing facility located in the Eagle Ford area of South Texas with an aggregate processing capacity of approximately 80,000 barrels per day;

- seven fractionation plants located throughout Canada and the United States with an aggregate gross processing capacity of approximately 221,800 barrels per day, and an isomerization and fractionation facility in California with an aggregate processing capacity of approximately 14,000 barrels per day;

Table of Contents

- 26 crude oil and NGL rail terminals located throughout the United States and Canada. See -Major Facilities Assets - Rail Facilities below for an overview of various terminals and Supply and Logistics regarding our use of railcars;

- six major marine facilities in the United States with an aggregate load capacity of 91,500 barrels per hour, including vapor recovery rates, and an aggregate unload capacity of 160,500 barrels per hour; and

- approximately 1,100 miles of active pipelines that support our facilities assets, consisting primarily of NGL and natural gas pipelines.

The following is a tabular presentation of our active facilities segment storage and service assets in the United States and Canada as of December 31, 2014, grouped by product and service type, with capacity and volume as indicated:

Crude Oil and Refined Products Storage Facilities	**Total Capacity (MMBbls)**
Cushing	20
LA Basin	8
Martinez and Richmond	5
Mobile and Ten Mile	2
Patoka	6
Philadelphia Area	4
St. James	10
Yorktown (1)	5
Other	13
	73

NGL Storage Facilities	**Total Capacity (MMBbls)**
Bumstead	4
Fort Saskatchewan	5
Sarnia Area	8
Tirzah	1
Other	5
	23

Natural Gas Storage Facilities	**Total Capacity (Bcf)**
Salt-caverns and Depleted Reservoir	97

Natural Gas Processing Facilities (2)	**Ownership Interest**	**Total Gas Inlet Volume (3) (Bcf/d)**	**Gross Gas Processing Capacity (4) (Bcf/d)**	**Net Gas Processing Capacity (4) (Bcf/d)**
United States Gulf Coast Area	100%	0.2	0.6	0.6
Canada	36-100%	1.3	6.7	5.4

	1.5	7.3	6.0

Condensate Stabilization Facility	Total Capacity (Bbls/d)
Gardendale	80,000

NGL Fractionation and Isomerization Facilities	Ownership Interest	Total Inlet Volume (3) (Bbls/d)	Gross Capacity (Bbls/d)	Net Capacity (Bbls/d)
Fort Saskatchewan	21-100%	23,622	75,000	51,300
Sarnia	62-84%	55,219	120,000	90,000
Shafter	100%	7,377	14,000	14,000
Other	82-100%	10,147	26,800	24,973
		96,365	235,800	180,273

Table of Contents

Rail Facilities	Ownership Interest	Loading Capacity (5) (Bbls/d)	Unloading Capacity (5) (Bbls/d)
Crude Oil Rail Facilities	100%	297,000	350,000

	Ownership Interest	Number of Rack Spots	Number of Storage Spots
NGL Rail Facilities **(4)**	50-100%	249	1,139

---

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

(2) While natural gas processing inlet volumes and capacity amounts are presented, they currently are not a significant driver of our segment results.

(3) Inlet volumes represent average inlet volumes net to our share for the entire year.

(4) Capacity transported will vary according to specification of product moved.

(5) Our NGL rail terminals are predominately utilized for internal purposes specifically for our supply and logistics activities. See our -Supply and Logistics Segment discussion following this section for further discussion regarding the use of our rail terminals.

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

Major Facilities Assets

Crude Oil and Refined Products Facilities

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 United States 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 source of refinery feedstock for Midwest and Gulf Coast refiners and plays an integral role in establishing and maintaining markets for many varieties of foreign and domestic crude oil. The Cushing Terminal has access to all major inbound and outbound pipelines in Cushing and is designed to handle multiple grades of crude oil while minimizing the interface and enabling deliveries to connecting carriers at their maximum rate.

Since 1999, we have completed multiple expansions that have increased the capacity of the Cushing Terminal to a total of 20 million barrels. During 2014, we added approximately 0.5 million barrels of such storage capacity through the construction of two 270,000 barrel tanks. Throughout 2015, we expect to add approximately 1.4 million barrels of storage through the construction of five additional 270,000 barrel tanks.

L.A. Basin. We own four crude oil and black oil storage facilities in the Los Angeles area with a total of 8 million barrels of storage capacity in commercial service and a distribution pipeline system of approximately 50 miles of pipeline in the Los Angeles Basin. We use the Los Angeles area storage and distribution system to service the storage and distribution needs of the refining, pipeline and marine terminal industries in the Los Angeles Basin. Our Los Angeles area system s pipeline distribution assets connect our storage assets with major refineries and third-party pipelines and marine terminals in the Los Angeles Basin.

Martinez and Richmond Terminals. We own two terminals in the San Francisco, California area: a terminal at Martinez (which provides refined product and crude oil service) and a terminal at Richmond (which provides refined product and black oil service). Our San Francisco area terminals have 5 million barrels of combined storage capacity and 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. These terminals have dock facilities and our Richmond terminal is also able to receive products by rail.

Mobile and Ten Mile Terminal. We have a marine terminal in Mobile, Alabama (the Mobile Terminal) that has current useable capacity of 2 million barrels. Approximately 4 million barrels of additional storage capacity is available at our nearby Ten Mile Facility, which is connected to our Mobile Terminal via a 36-inch pipeline. Of this capacity, approximately 0.5 million barrels supports our Facilities segment operations.

Table of Contents

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. Our Ten Mile Facility is connected to our Pascagoula pipeline, which was placed into service in early 2014.

Patoka Terminal. Our Patoka Terminal has 6 million barrels of storage capacity and the associated manifold and header system at the Patoka Interchange located in southern Illinois. Our terminal has access to all major pipelines and terminals at the Patoka Interchange. Patoka is a growing regional hub with access to domestic and foreign crude oil for certain volumes moving north on the Capline system as well as Canadian barrels moving south.

Philadelphia Area Terminals. We own four refined product terminals in the Philadelphia, Pennsylvania area. Our Philadelphia area terminals have a combined storage capacity of 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 the refiners in the Philadelphia harbor. The Philadelphia area terminals also receive products from connecting pipelines.

St. James Terminal. We have 10 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 is connected to major pipelines and other terminals and includes a manifold and header system that allows for receipts and deliveries with connecting pipelines at their maximum operating capacity. Over the past few years, we completed the construction of a marine dock that is able to receive from tankers and receive from, and load, barges. The facility is also connected to our rail unloading facility, which is being expanded to be capable of receiving heavy crude oil in 2015. See -Rail Facilities below for further discussion.

In 2014, we added approximately 1.2 million barrels of crude oil storage capacity to the St. James terminal, and we expect to add approximately 0.3 million barrels of storage capacity in 2015.

Yorktown Terminal. We have 5 million barrels of storage for crude oil and refined products at the Yorktown facility, including 1.1 million barrels of capacity for which we hold lease options (all of which have been exercised). The Yorktown facility has its own deep-water port on the York River with the capacity to service the receipt and delivery of product from ships and barges. This facility also has an active truck rack and rail capacity. See -Rail Facilities below for further discussion.

Corpus Christi. In 2014, we announced a joint project with Enterprise Products Partners L.P. to build a Corpus Christi terminal that will be capable of loading ocean going vessels at a rate of 20,000 barrels per hour. The facility will have access to production from both the Eagle Ford and the Permian Basin. The facility is expected to be placed in service by 2017.

NGL Storage Facilities

Bumstead. The Bumstead facility is located at a major rail transit point near Phoenix, Arizona. With 4 million barrels of useable capacity, the facility s primary assets include three salt-dome storage caverns, a 30-car rail rack and six truck racks.

Fort Saskatchewan. The Fort Saskatchewan facility is located approximately 16 miles northeast of Edmonton, Alberta in one of the key North American NGL hubs. The facility is a receipt, storage, fractionation and delivery facility for NGL and is connected to other major NGL plants and pipeline systems in the area. The facility s primary assets include 22 storage caverns with approximately 5 million barrels in useable storage capacity. The facility includes assets operated by us and assets operated by a third-party. Our ownership in the various facility assets ranges from approximately 21% to 100%. See the section entitled NGL Fractionation and Isomerization Facilities below for additional discussion of this facility.

During 2013, we began upgrading our Fort Saskatchewan storage capacity as part of a multi-phase expansion. The first phase of the expansion will add two new NGL storage caverns each with a capacity of 350,000 barrels and will convert approximately 2.2 million barrels of existing NGL mix storage capacity to propane and condensate storage supported by the addition of approximately 2.5 million barrels of new brine pond capacity.

Sarnia Area. The Sarnia facility is a large NGL fractionation, storage and shipping facility located on a 380 acre plant site in the Sarnia Chemical Valley. There are 36 multi-product railcar loading spots, 4 multi-product truck loading racks and a network of 14 pipelines providing product delivery capabilities to our Windsor, St. Clair and Green Springs terminal facilities, in addition to refineries, chemical plants and other pipeline systems in the area. The facility has approximately 3 million barrels in useable storage capacity. In 2013, we initiated a brine disposal program that will facilitate the removal of excess brine via truck from our Sarnia

Table of Contents

facility. The project is expected to increase useable NGL storage capacity at the facility by as much as 3 million barrels when completed.

The Windsor storage terminal in Windsor, Canada, is a pipeline hub and underground storage facility. The facility is served by three of our receipt/dispatch pipelines and rail and truck offloading. There are eight storage caverns on site with a useable capacity of approximately 3 million barrels. The primary terminal assets consist of 16 multi-product rail tank car loading spots and a propane truck loading rack. In 2014, we initiated a brine disposal program that will facilitate the removal of excess brine via pipeline from our Windsor storage terminal. The project is expected to increase useable NGL storage capacity at the facility by approximately 1 million barrels.

The St. Clair terminal is a propane, isobutane and butane storage and distribution facility located in St. Clair, Michigan and is connected to the Sarnia facility via one of our pipelines. On site are seven storage caverns with useable capacity of approximately 2 million barrels and 28 multi-product rail tank car loading spots.

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

Natural Gas Storage Facilities

We own three FERC regulated natural gas storage facilities located in the Gulf Coast and Midwest that are permitted for 149 Bcf of working gas capacity, and as of December 31, 2014, we had an aggregate working gas capacity of approximately 97 Bcf in service. Our facilities have aggregate peak daily injection and withdrawal rates of 4.1 Bcf and 6.4 Bcf, respectively.

Our natural gas storage facilities are strategically located and have a diverse group of customers, including utilities, pipelines, producers, power generators, marketers and liquefied natural gas (LNG) exporters, whose storage needs vary from traditional seasonal storage services to hourly balancing. We are located near several major market hubs, including the Henry Hub (the delivery point for NYMEX natural gas futures contracts), the Carthage Hub (located in East Texas), the Perryville Hub (located in North Louisiana), and the major market hubs of Chicago, Illinois and Dawn, Ontario. Our facilities service consumer and industrial markets in the Gulf Coast, Midwest, Mid-Atlantic, Northeast, and Southeast regions of the United States and the Southeastern portion of Canada through 20 interconnects with 12 interstate pipelines and 4 utility companies.

Natural Gas Processing Facilities

We own and/or operate four straddle plants and two field gas processing plants located in Western Canada with an aggregate gross natural gas processing capacity of approximately 6.7 Bcf per day and long-term liquid supply contracts relating to a third-party owned straddle plant with gross processing capacity of approximately 2.5 Bcf per day. We also own and operate five natural gas processing plants located in Louisiana and Alabama with an aggregate natural gas processing capacity of approximately 0.6 Bcf per day.

Condensate Processing Facility

Our Gardendale condensate processing facility in La Salle County, Texas is designed to extract natural gas liquids from condensate. The facility, which currently has two stabilizers and a capacity of 80,000 barrels per day, is adjacent to our Gardendale terminal and rail facility. Throughput at the Gardendale processing facility is supplied by long-term commitments from producers. During 2014, throughput averaged approximately 54,000 barrels per day. In December 2014, we received a letter from the BIS clarifying that the distillation processes employed at our Gardendale facility satisfies the conditions of the BIS to convert lease condensate into an exportable petroleum product.

In 2015, we expect to begin construction on a third stabilizer that will provide approximately 40,000 barrels per day of incremental capacity to the existing facility, bringing the total capacity to approximately 120,000 barrels per day. This project is expected to be in service in 2015. During 2015, we also expect to place in service a ten mile pipeline that will connect to a third party pipeline delivering NGL to Mont Belvieu.

NGL Fractionation and Isomerization Facilities

Fort Saskatchewan. Our Fort Saskatchewan facility has a fractionation capacity of approximately 45,000 barrels per day and produces both spec NGL products and NGL mix for delivery to the Sarnia facility via the Enbridge pipeline.

Table of Contents

The fractionation feedstock is supplied via the Fort Saskatchewan Pipeline System which connects to the Co-Ed NGL Pipeline System. Through ownership in the Keyera Fort Saskatchewan fractionation plant, (which has a gross fractionation capacity of 30,000 barrels per day), we have additional fractionation capacity, net to our share of 6,300 barrels per day.

We recently approved a project to expand our fractionation capacity to provide producers with additional fractionation infrastructure necessary to develop the significant liquids-rich natural gas reserves in western Canada. Once completed, this expansion will increase capacity to produce a combination of spec NGL products and NGL mix by 20,000 barrels per day. This project is supported by long-term fee-for-service agreements.

Sarnia. The Sarnia Fractionator is the largest fractionation plant in Eastern Canada and receives NGL feedstock from the Enbridge Pipeline and from refineries, gas plants and chemical plants in the area. The fractionation unit has a gross useable capacity of 120,000 barrels per day and produces specification propane, isobutane, normal butane and natural gasoline. Our ownership in the various processing units at the Sarnia Fractionator ranges from 62% to 84%.

Shafter. Our Shafter facility located near Bakersfield, California provides isomerization and fractionation services to producers and customers. The primary assets consist of approximately 200,000 barrels of NGL storage and a processing facility with butane isomerization capacity of approximately 14,000 barrels per day and NGL fractionation capacity of approximately 12,000 barrels per day.

We are in the process of commissioning a 15-mile NGL pipeline system that is capable of delivering up to 10,000 barrels per day from Occidental Petroleum Corporation s Elk Hills Gas plant to our Shafter facility. This project also included additions to our storage capacity and rail facilities.

Rail Facilities

Crude Oil Rail Loading Facilities

We own five active crude oil and condensate rail loading terminals that service production in the Niobrara, Eagle Ford and Bakken shale formations and have a combined loading capacity of approximately 297,000 barrels per day. These facilities are located in Carr, Colorado; Tampa, Colorado; Gardendale, Texas; Manitou, North Dakota; and Van Hook, North Dakota.

In 2014, we expanded our Van Hook and Carr terminals to increase loading capacity at each terminal from 35,000 and 15,000 barrels per day, respectively, to 68,000 barrels per day. We are currently constructing a rail terminal capable of loading 59,000 barrels per day of crude oil in Western Canada near Kerrobert, Saskatchewan. We expect to place this terminal in service in 2015.

Crude Oil Rail Unloading Facilities

We own three active crude oil rail unloading terminals that have a combined unloading capacity of approximately 350,000 barrels per day. Our terminal at St. James, Louisiana is connected to our rail unloading facility that has an unload capacity of 140,000 barrels of sweet crude oil per day. In late 2014, we approved a project to enhance our St. James rail facility with capability to receive heavy crude oil. We expect this project to be placed in service in 2015. Our Yorktown, Virginia rail facility receives unit trains and has an unload capacity of approximately 140,000 barrels per day, and our Bakersfield, California rail facility, which was placed into service in late 2014, receives unit trains and has permitted capacity to unload 70,000 barrels per day.

NGL Rail Facilities

We own 20 operational NGL rail facilities located throughout the United States and Canada that are strategically located near NGL storage, pipelines, gas production or propane distribution centers. Our NGL rail facilities currently have 249 railcar rack spots and 1,139 railcar storage spots and we have the ability to switch our own railcars at six of these terminals.

During 2014, we approved a number of expansion projects at our Fort Saskatchewan facility, including plans to develop a 60 car per day propane rail loading facility.

Supply and Logistics Segment

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

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

Table of Contents

- the storage of inventory during contango market conditions and the seasonal storage of NGL and natural gas;
- the purchase of NGL from producers, refiners, processors and other marketers;
- the resale or exchange of crude oil and NGL at various points along the distribution chain to refiners or other resellers;
- the transportation of crude oil and NGL on trucks, barges, railcars, pipelines and ocean-going vessels from various delivery points, market hub locations or directly to end users such as refineries, processors and fractionation facilities; and
- the purchase and sale of natural gas.

We characterize a substantial portion of our baseline segment profit generated by our supply and logistics segment as fee equivalent. This portion of the segment profit is generated by the purchase and resale of crude oil on an index-related basis, which results in us generating a gross margin for such activities. This gross margin is reduced by the transportation, facilities and other logistical costs associated with delivering the crude oil to market and carrying costs for hedged inventory, as well as any operating and general and administrative expenses. The level of profit associated with a portion of the other activities we conduct in the supply and logistics segment is influenced by overall market structure and the degree of market volatility, as well as variable operating expenses. The majority of activities that are carried out within our supply and logistics segment are designed to produce stable baseline results in a variety of market conditions, while at the same time providing upside potential associated with opportunities inherent in volatile market conditions (including opportunities to benefit from fluctuating differentials). These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies. The tankage that is used to support our arbitrage activities positions us to capture margins in various market conditions. See Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model below for further discussion.

In addition to hedged working inventories associated with its merchant activities, as of December 31, 2014, our supply and logistics segment also owned significant volumes of crude oil and NGL classified as long-term assets and linefill or minimum inventory requirements and employed a variety of owned or leased physical assets throughout the United States and Canada, including approximately:

- 13 million barrels of crude oil and NGL linefill in pipelines owned by us;
- 4 million barrels of crude oil and NGL linefill in pipelines owned by third parties and other long-term inventory;
- 990 trucks and 1,100 trailers; and

- 8,100 crude oil and NGL railcars (additionally, over 1,400 new crude oil railcars on order with delivery expected in 2015).

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

The following table shows the average daily volume of our supply and logistics activities for the year ended December 31, 2014 (in thousands of barrels per day):

	Volumes
Crude oil lease gathering purchases	949
NGL sales	208
Supply and Logistics activities total	1,157

Crude Oil and NGL Purchases. We purchase crude oil and NGL from multiple producers under contracts and believe that we have established long-term, broad-based relationships with the crude oil and NGL producers in our areas of operations. Our crude oil contracts generally range in term from thirty-day evergreen to five years, with the majority ranging from thirty days to one year and a limited number of contracts extending up to seven years. We utilize our truck fleet and pipelines as well as leased railcars, third-party pipelines, trucks and barges to transport the crude oil to market. In addition, from time to time, we purchase foreign crude oil.

Table of Contents

Under these contracts we may purchase crude oil upon delivery in the United States or we may purchase crude oil in foreign locations and transport it on third-party tankers. From time to time, we enter into various types of purchase and exchange transactions including fixed price purchase contracts, collars, financial swaps and crude oil and NGL-related futures contracts as hedging devices.

We purchase NGL from producers, refiners, and other NGL marketing companies under contracts that typically have ranged from immediate delivery to one year in term. With the shortage of fractionation and storage space in Western Canada, we are pursuing an increasing number of contracts with longer terms to firm up capacity utilization and base-load expansion projects. We utilize our trucking fleet and pipeline network, as well as leased railcars, third-party tank trucks and third-party pipelines to transport NGL.

In addition to purchasing crude oil from producers, we purchase both domestic and foreign crude oil in bulk at major pipeline terminal locations, rail and barge facilities. We also purchase NGL in bulk at major pipeline terminal points and storage facilities from major integrated oil companies, large independent producers or other NGL marketing companies or processors. Crude oil and NGL are purchased in bulk when we believe additional opportunities exist to realize margins further downstream in the crude oil or NGL 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 NGL Sales. The activities involved in the supply, logistics and distribution of crude oil and NGL are complex and require current detailed knowledge of crude oil and NGL sources and end markets, as well as a familiarity with a number of factors including grades of crude oil, individual refinery demand for specific grades of crude oil, area market price structures, location of customers, various modes and availability of transportation facilities and timing and costs (including storage) involved in delivering crude oil and NGL 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. Our crude oil sales contracts generally range in term from thirty-day evergreen to five years, with the majority ranging from thirty days to one year and a limited number of contracts extending up to seven years. We sell NGL primarily to propane and refined product retailers, petrochemical companies and refiners, and limited volumes to other marketers. A majority of our NGL contracts generally range in term from a thirty-day evergreen to one year. With the move to longer term (greater than one year) NGL supply contracts, longer term NGL sale contracts are also becoming more commonplace, usually with flexible pricing mechanisms to ensure the sale remains market-based for both buyer and seller. We establish a margin for the crude oil and NGL 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 exchanges. 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, collars, financial swaps and crude oil and NGL-related futures contracts as hedging devices.

Crude Oil and NGL 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 NGL that more closely matches our physical delivery requirement, location or the preferences of our customers, we exchange physical crude oil or NGL, 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 NGL that differs in terms of geographic location, grade of crude oil or type of NGL, or physical delivery schedule from crude oil or NGL we have available for sale. Generally, we enter into exchanges to acquire crude oil or NGL 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.

Natural Gas Purchase and Sales Activities. We also generate net revenue through the merchant storage activities of our natural gas commercial marketing group, which captures short term market opportunities by utilizing a portion of our natural gas storage capacity and engaging in related commercial marketing activities. Our natural gas merchant storage activities generate revenue through the hedged purchase and sale of natural gas net of any storage-related costs incurred. We utilize physical natural gas storage at our facilities and derivatives to hedge expected margin from these activities. Through these transactions, we seek to maintain a position that is substantially balanced between purchases of natural gas on the one hand and sales or future delivery obligations on the other hand.

In connection with our natural gas merchant storage activities, we incur certain storage-related costs. These costs consist of fees incurred to secure third-party pipeline capacity and natural gas storage and transaction costs associated with managing injection and deliverability capacity at our facilities. Costs associated with our third-party pipeline capacity are subject to variation as the terms of these agreements typically contain certain fees which fluctuate based on actual volumes shipped in addition to monthly reservation fees.

Table of Contents

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

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

Because our typical sales transactions can involve large volumes of crude oil and natural gas, 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 and natural gas 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 NGL (principally propane); 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 NGL on a forward basis, as well as to sell NGL on a current basis to local distributors and retailers. In certain cases our NGL customers prepay for their purchases, in amounts ranging up to 100% of their contracted amounts.

Certain activities in our supply and logistics segment are affected by seasonal aspects, primarily with respect to NGL and natural gas supply and logistics activities.

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

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

Crude oil, NGL, natural gas and refined products commodity prices have historically been very volatile. For example, since the mid-1980s, NYMEX West Texas Intermediate (WTI) crude oil benchmark prices have ranged from a low of approximately $10 per barrel during 1986 to a high of over $147 per barrel during 2008. During 2014, West Texas Intermediate crude oil prices traded within a range of $53 to $107 per barrel. There is also volatility within the propane and butane markets as seen through the North American benchmark price located at Mont Belvieu, Texas. Specifically, propane prices have ranged from a low of approximately 43% of the WTI benchmark price for crude oil in 2013 to a high of approximately 81% of the WTI benchmark price for crude oil in 2000. Butane has seen a price range from a low of approximately 55% of the WTI benchmark price for crude oil in 2014 to a high of approximately 93% of the WTI benchmark price for crude oil in 2000.

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

Base level segment profit from our supply and logistics activities is dependent on our ability to sell crude oil and NGL at prices in excess of our aggregate cost. Although segment profit may be adversely affected during certain transitional periods, our crude oil and NGL supply, logistics and distribution operations are not directly affected by the absolute level of prices, but are affected by overall levels of supply and demand for crude oil and NGL and relative fluctuations in market-related indices.

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

Table of Contents

In addition to providing a durable base level of cash flow, this approach is also intended to provide opportunities to realize incremental margin during volatile market conditions. For example, if crude oil prices are high relative to historical levels, we may hedge some of our expected pipeline loss allowance barrels, and if crude oil prices are low relative to historical prices, we may hedge a portion of our anticipated diesel purchases needed to operate our trucks and barges. Also, during periods when supply exceeds the demand for crude oil, NGL or natural gas in the near term, the market for such product is often in contango, meaning that the price for future deliveries is higher than current prices. In a contango market, entities that have access to storage at major trading locations can purchase crude oil, NGL or natural gas at current prices for storage and simultaneously sell forward such products for future delivery at higher prices.

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

Risk Management

In order to hedge margins involving our physical assets and manage risks associated with our various commodity purchase and sale obligations and, in certain circumstances, to realize incremental margin during volatile market conditions, we use derivative instruments. We also use various derivative instruments to manage our exposure to interest rate risk and currency exchange rate risk. In analyzing our risk management activities, we draw a distinction between enterprise level risks and trading-related risks. Enterprise level risks are those that underlie our core businesses and may be managed based on management s assessment of the cost or benefit in doing so. Conversely, trading-related risks (the risks involved in trading in the hopes of generating an increased return) are not inherent in our core business; rather, those risks arise as a result of engaging in the trading activity. Our policy is to manage the enterprise level risks inherent in our core businesses, rather than trying to profit from trading activity. Our 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 currency exchange rate risk management policies and procedures are designed to monitor our derivative positions and ensure that those positions are consistent with our objectives and approved strategies. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities and procedures and certain other aspects of corporate risk management. Our risk management function also approves all new risk management strategies through a formal process. Our approved strategies are intended to mitigate and manage enterprise level risks that are inherent in our core businesses.

Except for pre-defined inventory positions, our policy is generally to structure our purchase and sales contracts so that price fluctuations do not materially affect our operating income, and not to acquire and hold physical inventory or derivatives 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, NGL and natural gas from thousands of locations and may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions and other uncontrollable events that occur within each month. When unscheduled physical inventory builds or draws do occur, they are monitored constantly and managed to a balanced position over a reasonable period of time. This activity is monitored independently by our risk management function and must take place within predefined limits and authorizations.

Geographic Data; Financial Information about Segments

See Note 19 to our Consolidated Financial Statements.

Customers

Marathon Petroleum Corporation and its subsidiaries accounted for approximately 17%, 15% and 16% of our revenues for the years ended December 31, 2014, 2013 and 2012, respectively. ExxonMobil Corporation and its subsidiaries accounted for approximately 15% for the year ended December 31, 2014 and approximately 13% of our revenues for each of the years ended December 31, 2013 and 2012. Phillips 66 and its subsidiaries accounted for approximately 11% of our revenues for the year ended December 31, 2013. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2014, 2013 and 2012. The majority of revenues from these customers pertain to our supply and logistics operations. The sales to these customers occur at multiple locations and 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

Table of Contents

comparable margins. For a discussion of customers and industry concentration risk, see Note 14 to our Consolidated Financial Statements.

Competition

Competition among pipelines is based primarily on transportation charges, access to producing areas and supply regions and demand for the crude oil and NGL by end users. We believe that high capital requirements, environmental considerations and the difficulty in acquiring rights-of-way and related permits make it unlikely that competing pipeline systems comparable in size and scope to our pipeline systems will be built in the foreseeable future. However, to the extent there are already third-party owned pipelines or owners with joint venture pipelines with excess capacity in the vicinity of our operations, we are exposed to significant competition based on the relatively low cost of moving an incremental barrel of crude oil or NGL. In addition, in areas where additional infrastructure is necessary to accommodate new or increased production or changing product flows, we face competition in providing the required infrastructure solutions as well as the risk of building capacity in excess of sustained demand. Depending upon the specific movement, pipelines, which generally offer the lowest cost of transportation, may also face competition from other forms of transportation, such as rail and barge. Although these alternative forms of transportation are typically higher cost, they can provide access to alternative markets at which a higher price may be realized for the commodity being transported, thereby overcoming the increased transportation cost.

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

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 pipeline companies 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 and/or enforcement actions. In 2010 we settled by means of separate Consent Decrees, two Department of Justice (DOJ)/Environmental Protection Agency (EPA) proceedings regarding certain releases of crude oil. One Consent Decree applied to our crude oil pipelines in general and was terminated in November 2013. The remaining Consent Decree applies to a specific system. Although we believe that all material aspects of the injunctive elements of the remaining Consent Decree (costs and operational effects) have been incorporated into our budgeting and planning process, future proceedings could result in additional injunctive remedies, the effect of which would subject us to operational requirements and constraints that would not apply to our competitors.

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

Environmental, Health and Safety Regulation

General

Our operations involving the storage, treatment, processing and transportation of liquid hydrocarbons including crude oil are subject to stringent federal, state, provincial and local laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment. As with the industry generally, compliance with these laws and regulations increases our overall cost of doing business, including our capital costs to construct, maintain and upgrade equipment and facilities. Failure to comply with these laws and regulations could result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory and remedial liabilities and the issuance of injunctions that may subject us to additional operational constraints that our competitors are not required to follow. Environmental and safety laws and regulations are subject to changes that

Table of Contents

may result in more stringent requirements, and we cannot provide any assurance that compliance with current and future laws and regulations will not have a material effect on our results of operations or earnings. A discharge of hazardous liquids into the environment could, to the extent such event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and any claims made by third parties. The following is a summary of some of the environmental and safety laws and regulations to which our operations are subject.

Pipeline Safety/Pipeline and Storage Tank Integrity Management

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

United States

The HLPSA was amended by the Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. These amendments have resulted in the adoption of rules by the Department of Transportation (DOT) that require transportation pipeline operators to implement integrity management programs, including more frequent inspections, correction of identified anomalies and other measures, to ensure pipeline safety in high consequence areas such as high population areas, areas unusually sensitive to environmental damage, and commercially navigable waterways. In the United States, our costs associated with the inspection, testing and correction of identified anomalies were approximately $107 million in 2014, $57 million in 2013 and $39 million in 2012. Based on currently available information, our preliminary estimate for 2015 is that we will incur approximately $75 million in capital expenditures and approximately $27 million in operational expenditures associated with our required pipeline integrity management program. Significant additional expenses could be incurred if new or more stringently interpreted pipeline safety requirements are implemented. Currently, we believe our pipelines are in substantial compliance with HLPSA and the 2002 and 2006 amendments. In addition to required activities, our integrity management program includes several voluntary, multi-year initiatives designed to prevent incidents. Costs incurred for such activities were approximately $21 million in 2014, $22 million in 2013 and $24 million in 2012, and our preliminary estimate for 2015 is that we will incur approximately $31 million of such costs.

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

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

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

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

The DOT has adopted American Petroleum Institute Standard 653 (API 653) as the standard for the inspection, repair, alteration and reconstruction of steel aboveground petroleum storage tanks subject to DOT jurisdiction. API 653 requires regularly scheduled inspection and repair of tanks remaining in service. In the United States, costs associated with this program were approximately $32 million, $26 million and $31 million in 2014, 2013 and 2012, respectively. For 2015, we have budgeted approximately $34 million in connection with continued API 653 compliance activities and similar new EPA regulations for tanks not regulated by the DOT. Certain storage tanks may be taken out of service if we believe the cost of compliance will exceed the value of the storage tanks or replacement tankage may be constructed.

Canada

In Canada, the NEB and provincial agencies such as the Alberta Energy Regulator (f/k/a the Energy Resources Conservation Board) (AER) and the Saskatchewan Ministry of Economy regulate the safety and integrity management of pipelines and storage tanks used for hydrocarbon transmission. We have incurred and will continue to incur costs related to such regulatory requirements. In 2013 the AER issued an order under Section 22 of the Oil and Gas Conservation Act imposing additional regulatory requirements on PMC with respect to obtaining operating approvals under such Act and ordering an AER audit of PMC s operations. This order was lifted in 2014 following completion of the audit and release of the AER audit report. In 2014, the NEB gave notice that it was assessing our Canadian operations for compliance with the National Energy Board Onshore Pipeline Regulations (2013), and in respect of prior corrective actions ordered by the NEB pursuant to a 2009 audit under the predecessor Onshore Pipeline Regulations (1999). The NEB completed its assessment and issued an order in 2015 requiring PMC to file its safety critical tasks, controls and quality assurance program. The order also mandated third party audits of PMC s management system and environmental protection program, and that corrective action plans for any identified deficiencies must be filed by the end of 2015, while a third party audit of PMC s integrity management program along with corrective action plans must be filed by the end of 2016. Although we believe that all material aspects of the NEB order (costs and operational effects) have been incorporated into our budgeting and planning process, future NEB orders could result in additional operational requirements and constraints that would not apply to our competitors.

In addition to required activities, our integrity management program includes several voluntary, multi-year programs designed to prevent incidents, such as upgrades to our operating and maintenance programs and systems and upgrades to our pipeline watercourse crossing integrity program. Between such required and elective activities, we spent approximately $66 million, $90 million and $80 million in 2014, 2013 and 2012, respectively. Our preliminary estimate for 2015 is approximately $99 million.

Although we believe that our pipeline operations are in substantial compliance with currently applicable regulatory requirements, we cannot predict the potential costs associated with additional, future regulation. For example, on December 9, 2014, new legislation was proposed at the federal level (Bill C-45 Proposed Pipeline Safety Act) which is intended to strengthen incident prevention, preparedness and response, liability and compensation to further enhance the safety of federally-regulated pipelines. It is anticipated this legislation will be passed into law in 2015. Significant additional expenses could be incurred if new or more stringently interpreted pipeline safety requirements are implemented, though our competitors would also be affected to a similar degree.

Occupational Safety and Health

United States

In the United States, 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. Certain of our facilities are subject to OSHA Process Safety Management (PSM) regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above specified thresholds or any process that involves 10,000 pounds or more of a flammable liquid or gas in one location. 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.

Canada

Similar regulatory requirements exist in Canada under the federal and provincial Occupational Health and Safety Acts, Regulations and Codes. The agencies with jurisdiction under these regulations are empowered to enforce them through inspection, audit, incident investigation or investigation of a public or employee complaint. In some jurisdictions, the agencies have been empowered to administer penalties for contraventions without the company first being prosecuted. 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.

Table of Contents

Solid Waste

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

Hazardous Substances

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

We are subject to the EPA s Risk Management Plan regulations at certain facilities. These regulations are intended to work with OSHA s PSM regulations (see Occupational Safety and Health above) to minimize the offsite consequences of catastrophic releases. The regulations require us to develop and implement a risk management program that includes a five-year accident history, an offsite consequence analysis process, a prevention program and an emergency response program. We believe we are operating in substantial compliance with our risk management program.

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.

Assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified. We have in the past experienced and in the future will likely experience releases of crude oil into the environment from our pipeline and storage operations. We may also discover environmental impacts from past releases that were previously unidentified.

Air Emissions

Our United States operations are subject to the United States Clean Air Act (Clean Air Act), comparable state laws and associated state and federal regulations. Our Canadian operations are subject to federal and provincial air emission regulations. The new Canadian standards for air quality and industrial air emissions were implemented in May 2013. The new standards provide more stringent objectives for outdoor air quality, including for the first time in Canada, a long term (annual) target for fine particulate matter. Under these laws, permits may be required before construction can commence on a new or modified source of potentially significant air emissions, and operating permits may be required for sources already constructed. We may be required to incur certain capital and operating expenditures in the next several years to install air pollution control equipment and otherwise comply with more stringent federal, state, provincial and regional air emissions control requirements 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

Table of Contents

areas in which we operate, we can provide no assurance that future compliance obligations will not have a material adverse effect on our financial condition or results of operations.

Climate Change Initiatives

United States

A number of studies have been conducted by various parties which represent to be authoritative on the issue of emissions of carbon dioxide and certain other gases, generally referred to as greenhouse gases (GHG). Many of these studies draw conflicting conclusions as to whether GHG is contributing to warming of the Earth s atmosphere. In 2009, the EPA adopted rules for establishing a GHG emissions reporting program. Fewer than ten of our facilities are presently subject to the federal GHG reporting requirements. These include facilities with combustion GHG emissions and potential fugitive emissions above the reporting thresholds. We import sufficient quantities of finished fuel products into the United States to be required to report that activity as well. We also continue to monitor GHG emissions for all of our facilities and activities. At the present time, we do not anticipate the need to purchase a material amount of GHG credits or install control technology to reduce GHG emissions at any of our facilities.

In 2010, the EPA promulgated regulations establishing Title V and Prevention of Significant Deterioration permitting requirements for large sources of GHGs (a portion of these regulations were overturned by the U.S. Supreme Court in 2014). Fewer than ten of our existing facilities are potential major sources of GHG subject to these permitting requirements. We may be required to install best available control technology or (BACT) to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they emit quantities of GHGs that trigger the requirements of these regulations. The EPA is in the process of establishing BACT for various sources of GHG emissions, but it appears likely that, for facilities such as ours, BACT will normally take the form of enhanced energy efficiency measures rather than post-combustion GHG capture requirements. We do not anticipate that the imposition of enhanced energy efficiency requirements would have an adverse material effect on the cost of our operations.

California has implemented a GHG cap-and-trade program, authorized under Assembly Bill 32 (AB32). Through 2014, California s cap-and-trade program has only applied to large industrial facilities. The California Air Resources Board has published a list of facilities that are subject to this program. At this time, the list only includes one of our facilities, the Lone Star Gas Liquids facility in Shafter, California. Beginning January 1, 2015, the AB32 regulations for the first time cover finished fuel providers and importers. California finished fuel providers (refiners and importers) will be required to purchase GHG emission credits for finished fuel sold in or imported into California. The rules implementing the AB32 program were finalized in December 2011. The compliance requirements of the GHG cap-and-trade program through 2020 are being phased in, and we do not anticipate any problems in complying with those obligations going forward or for such impacts to be material. The California Air Resources Board is currently developing a scoping plan for AB32 compliance obligations after the year 2020.

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

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, demand for our services, financial condition, results of operations and cash flows, though our competitors would also be affected to a similar degree. 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.

Canada

Pursuant to the 1997 United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol , many nations, including Canada, agreed to limit emissions of GHGs. The Kyoto Protocol required Canada to reduce its emissions of GHG to 6% below 1990 levels by 2012. However, by 2009, emissions in Canada were 17% higher than 1990 levels. In December 2011, Canada withdrew from the Kyoto Protocol, but signed the Durban Platform committing it to a legally binding treaty to reduce GHG emissions, the terms of which are to be defined by 2015 and are to become effective in 2020.

Table of Contents

In 2007, in response to the Kyoto Protocol, the Canadian federal government introduced the *Regulatory Framework for Air Emissions* (also known as the Turning the Corner measures), a regulatory framework for monitoring industrial GHG emissions by establishing mandatory emissions reduction requirements on a sector basis. Since 2004, companies emitting more than 100 thousand tons per year (kt/y) of CO_2 equivalent (CO_2e) were required to report their GHG emissions under the Greenhouse Gas Emissions Reporting Program. In 2010, this reporting threshold was reduced to 50 kt/y. Two PMC facilities meet this reporting threshold. Originally, the framework was intended to be implemented by 2010; however no federally mandated reduction targets for GHGs have been implemented to date. Canada has taken sectoral action on two of its largest sources of emissions electricity and vehicles. Construction of traditional coal fired generation has been banned and new vehicle emissions and fuel efficiency standards have been established through to 2025.

In Alberta, the provincial government implemented the Specified Gas Emitter Regulation in 2007 (under the Alberta Environment Protection and Enhancement Act), which mandated a 12% reduction in emission intensity over the established baseline level (average of the 2003-2005 levels) for all facilities emitting more than 100kt/y of CO_2e. Since the regulation came into effect, PMC has one facility (Fort Saskatchewan Storage and Fractionation Facility) which currently does not meet the reduction obligation. As such, PMC has been required to submit compliance credits which have been completed by submitting payment to the Climate Change Emissions Management Fund. Alberta also has a GHG reporting threshold at 50kt/y of CO_2e.

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

Water

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act (CWA), and analogous state and Canadian federal and provincial laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters of the United States and Canada, as well as state and provincial waters. See Pipeline Safety/Pipeline and Storage Tank Integrity Management above and Note 17 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.

With respect to our new pipeline construction activities and maintenance on our existing pipelines, Section 404 of the CWA authorizes the Army Corps of Engineers (Corps) to permit the discharge of dredged or fill materials into navigable waters, which are defined as the waters of the United States. Section 404 (e) authorizes the Corps to issue permits on a nationwide basis for categories of discharges that have no more than minimal individual or cumulative environmental effects. For the past 35 years, the Corps has authorized construction, maintenance and repair of pipelines under a streamlined nationwide permit program known as Nationwide Permit 12 (NWP). The NWP is supported by strong statutory and regulatory history and was originally approved by Congress in 1977. From time to time, several environmental groups have challenged the NWP; however, to date, federal courts have upheld the validity of the NWP under the CWA. We cannot predict whether future lawsuits will be filed to contest the validity of the NWP; however, in the event that a court wholly or partially strikes down the NWP, which we believe to be unlikely, we could face significant delays and financial costs when seeking project approvals.

Endangered Species

New projects may require approvals and environmental analysis under federal, state and provincial laws, including the National Environmental Policy Act and the Endangered Species Act in the United States and the Species at Risk Act in Canada. The resulting costs and liabilities could materially and negatively affect the viability of such projects.

Table of Contents

Other Regulation

Transportation Regulation

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

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

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

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

Energy Policy Act of 1992 and Subsequent Developments. In October 1992, Congress passed the Energy Policy Act of 1992 (EPAct), which, among other things, required the FERC to issue rules to establish a simplified and generally applicable ratemaking methodology for petroleum pipelines and to streamline procedures in petroleum pipeline proceedings. The FERC responded to this mandate by establishing a formulaic methodology for petroleum pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index. The FERC reviews the formula every five years. Effective July 1, 2011, the annual index adjustment for the five year period ending June 30, 2016 will equal the producer price index for finished goods for the applicable year plus an adjustment factor of 2.65%. Pipelines may raise their rates to the rate ceiling level generated by application of the annual index adjustment factor each year; however, a shipper may challenge such increase if the increase in the pipeline s rates was substantially in excess of the actual cost increases incurred by the pipeline during the relevant year. If the FERC s annual index adjustment 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 the EPAct (see below) to below the grandfathered level. A pipeline must, as a general rule, use the indexing methodology to change its rates. The FERC, however, retained cost-of-service ratemaking, market-based rates and settlement rates as alternatives to the indexing approach that may be used in certain specified circumstances. Because the indexing methodology for the next five-year period is tied to an inflation index and is not based on pipeline-specific costs, the indexing methodology could hamper our ability to recover cost increases.

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

Canadian Regulation. Our Canadian pipeline assets are subject to regulation by the NEB and by provincial authorities, such as the AER. 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.

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

Table of Contents

Trucking Regulation

United States

We operate a fleet of trucks to transport crude oil and oilfield materials as a private, contract and common carrier. We are licensed to perform both intrastate and interstate motor carrier services. As a motor carrier, we are subject to certain safety regulations issued by the DOT. The trucking regulations cover, among other things: (i) driver operations, (ii) log book maintenance, (iii) truck manifest preparations, (iv) safety placard placement on the trucks and trailer vehicles, (v) drug and alcohol testing, (vi) operation and equipment safety and (vii) many other aspects of truck operations. We are also subject to OSHA with respect to our trucking operations.

Canada

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

Railcar Regulation

We operate a number of railcar loading and unloading facilities, and lease a significant number of railcars, in the United States and Canada. Our railcar operations are subject to the regulatory jurisdiction of the Federal Railroad Administration of the DOT, the Occupational Safety and Health Administration, as well as other federal and state regulatory agencies and Canadian regulatory agencies for operations in Canada. We believe that our railcar operations are in substantial compliance with all existing federal, state, and local regulations.

Railcar accidents in Lac-Megantic, Quebec, Aliceville, Alabama and Casselton, North Dakota involving derailments and explosions have led to increased regulatory scrutiny over the safety of transporting crude oil by rail. All of these incidents, together with more recent incidents in Lynchburg, Virginia and Fayette County, West Virginia, involved trains carrying crude oil from North Dakota s Bakken shale formation. In the wake of the Casselton derailment, PHMSA issued a safety advisory warning that Bakken crude may be more flammable than other grades of crude oil and reinforcing the requirement to properly test, characterize, classify, and where appropriate sufficiently degasify hazardous materials prior to and during transportation. PHMSA also initiated Operation Classification , a compliance initiative involving unannounced inspections and testing of crude oil samples to verify that offerors of the materials have properly classified, described and labeled the hazardous materials before transportation. On February 25, 2014, the DOT issued an emergency order designed to insure that crude oil is properly tested and classified prior to transportation by rail in accordance with existing hazardous materials regulations. The DOT emergency order also provides for potential penalties for non-compliance of up to $175,000 per violation. While we believe that we are in material compliance with existing regulations governing our railcar operations, the extent to which the DOT s emergency order requires additional procedures has not yet been fully established; accordingly, we cannot predict the impact that the DOT order and any future regulations may have on our operations.

These accidents have prompted lawmakers to step up their efforts to phase out or require upgrades on the DOT Class 111 tank railcar, the most commonly used tank car to transport crude oil by railcar in North America. A DOT Class 111 rail tanker is not pressurized, unlike sturdier DOT-112 and -114 models used to transport more volatile liquids such as propane and methane. The U.S. National Transportation Safety Board (NTSB) has recommended that all tank cars used to carry crude oil be reinforced to make them more resistant to punctures if trains derail. In response to the NTSB recommendations, in July 2014, the DOT released a Notice of Proposed Rulemaking (NPRM). The NPRM proposes enhanced tank car standards, a classification and testing program for mined gases and liquids and new operational requirements for high-hazard flammable trains that included braking controls and speed restrictions. Specifically, within two years, the NPRM proposes the phase out of the use of older DOT-111 tank cars for the shipment of packing group I flammable liquids, including most Bakken crude oil, unless the tank cars are retrofitted to comply with the new tank car design requirements. We do not anticipate that any requirement to retrofit and upgrade existing rail tankers (DOT-111 or other models) would involve material cost to the partnership. The new, comprehensive rulemaking was open for public comment through September 30, 2014 and will likely take months to finalize. Similar changes have been proposed in Canada.

In December 2014, the North Dakota Industrial Commission adopted new standards to improve the safety of Bakken crude oil for transport. The new standard, Commission Order 25417, is effective April 1, 2015, and requires operators/producers to condition Bakken crude oil to certain vapor pressure limits. Under the order, all Bakken crude oil produced in North Dakota will be conditioned with no exceptions. The order requires operators/producers to separate light hydrocarbons from all Bakken crude oil to be transported and prohibits the blending of light hydrocarbons back into oil supplies prior to shipment. We are not directly responsible for the conditioning or stabilization of Bakken crude oil, however, under the order, it is our responsibility to notify the State of North Dakota upon discovering that Bakken crude oil received at our rail facility exceeds certain vapor pressure limits.

Table of Contents

Cross Border Regulation

As a result of our cross border activities, including importation of crude oil, NGL and natural gas between the United States and Canada, we are subject to a variety of legal requirements pertaining to such activities including export/import license requirements, tariffs, Canadian and U.S. customs and taxes and requirements relating to toxic substances. U.S. legal requirements relating to these activities include regulations adopted pursuant to the Short Supply Controls of the Export Administration Act, the North American Free Trade Agreement and the Toxic Substances Control Act. In addition, the importation and exportation of natural gas from and to the United States and Canada is subject to regulation by U.S. Customs and Border Protection, U.S. Department of Energy and the NEB. 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. federal, state and local tax requirements, as well as Canadian federal and provincial tax requirements, could lead to the imposition of additional taxes, interest and penalties.

Market Anti-Manipulation Regulation

In November 2009, the Federal Trade Commission (FTC) issued regulations pursuant to the Energy Independence and Security Act of 2007, intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to $1 million per violation per day. In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the Commodity Futures Trading Commission (CFTC) to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to crude oil swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to crude oil purchases and sales. In July 2011, the CFTC issued final rules to implement their new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of $1 million or triple the monetary gain to the person for each violation.

We have not experienced a material impact from the FTC or CFTC regulations.

Natural Gas Storage Regulation

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

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

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

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

Table of Contents

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

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

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 35 times since the end of 1998. At the same time that the scale and scope of our business activities have expanded, the breadth and depth of the available insurance markets have contracted. The overall cost of such insurance as well as the deductibles and overall retention levels that we maintain have increased. As a result, we have elected to self-insure more activities against certain of these operating hazards and expect this trend will continue in the future. Due to the events of September 11, 2001, insurers have excluded acts of terrorism and sabotage from our insurance policies. We have elected to purchase a separate insurance policy for acts of terrorism and sabotage.

Since the terrorist attacks, the United States Government has issued numerous warnings that energy assets, including our nation s pipeline infrastructure, may be future targets of terrorist organizations. These developments expose our operations and assets to increased risks. We have instituted security measures and procedures in conformity with DOT guidance. We will institute, as appropriate, additional security measures or procedures indicated by the DOT or the Transportation Safety Administration. However, there can be no assurance 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 third-party liability and property damage to others with respect to our operations. We believe that our levels of coverage and retention are generally consistent with those of similarly situated companies in our industry. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable, or that we have established adequate reserves to the extent that such risks are not insured.

Title to Properties and Rights-of-Way

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

Table of Contents

Employees and Labor Relations

To carry out our operations, our general partner or its affiliates (including PMC) employed approximately 5,300 employees at December 31, 2014. None of the employees of our general partner are subject to a collective bargaining agreement, except for nine employees covered by an agreement scheduled for renegotiation in September 2015 and another nine employees covered by another agreement scheduled for renegotiation in September 2016. Our general partner considers its employee relations to be good.

Summary of Tax Considerations

The following is a brief summary of material tax considerations of owning and disposing of common units, however, the tax consequences of ownership of common units depends in part on the owner s individual tax circumstances. It is the responsibility of each unitholder, either individually or through a tax advisor, to investigate the legal and tax consequences, under the laws of pertinent U.S. federal, states and localities, as well as Canada and the Canadian provinces, 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. Also see Item 1A. Risk Factors Tax Risks to Common Unitholders.

Partnership Status; Cash Distributions

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

Partnership Allocations

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

Basis of Common Units

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

Limitations on Deductibility of Partnership Losses

The deduction by a unitholder of that unitholder s allocable share of our losses will be limited to the amount of that unitholder s tax basis in his or her common units and, in the case of an individual unitholder or a corporate unitholder who is subject to the at risk rules (generally, certain closely-held corporations), to the amount for which the unitholder is considered to be at risk with respect to our activities, if that is less than the unitholder s tax basis. A unitholder must recapture losses deducted in previous years to the extent that distributions cause the unitholder s at risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable as a deduction to the

Table of Contents

extent that his at-risk amount is subsequently increased, provided such losses do not exceed such unitholder s tax basis in his common units. Upon the taxable disposition of a common unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but may not be offset by losses suspended by the basis limitation. Any loss previously suspended by the at risk limitation in excess of that gain could no longer be used.

In addition to the basis and at-risk limitations described above, a passive activity loss limitation generally limits the deductibility of losses incurred by individuals, estates, trusts, some closely-held corporations and personal service corporations from passive activities (generally, trade or business activities in which the taxpayer does not materially participate). The passive loss limitations are applied separately with respect to each publicly-traded partnership. Consequently, any passive losses we generate will be available to offset only passive income generated by us, and will not be available to offset income from other passive activities or investments, including investments in other publicly traded partnerships or salary, active business or other income. Passive losses that exceed a unitholder s share of passive income we generate may be deducted in full when the unitholder disposes of all of its units in a fully taxable transaction with an unrelated party. The passive activity loss rules are generally applied after other applicable limitations on deductions, including the at risk and basis limitations.

Section 754 Election

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

Disposition of Common Units

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

State, Local and Other Tax Considerations

In addition to federal income taxes, unitholders will likely be subject to other taxes, including state and local income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which a unitholder resides or in which we conduct business or own property. We own property and conduct business in most states in the United States as well as several provinces in Canada. A unitholder may also be required to file state income tax returns and to pay taxes in various states, even if they do not live in those jurisdictions. As our entire Canadian source income passes through Canadian taxable entities, our unitholders do not have a separate Canadian tax filing obligation as it relates to this income. Unitholders who are not resident in the United States may have additional tax reporting and payment requirements.

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

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

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

Table of Contents

Available Information

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

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

Risks Related to Our Business

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

We have a number of organic growth projects that involve the construction of new midstream energy infrastructure assets or the expansion or modification of existing assets. Many of these projects involve numerous regulatory, environmental, commercial, economic, weather-related, political and legal uncertainties that are beyond our control, including the following:

- As these projects are undertaken, required approvals, permits and licenses may not be obtained, may be delayed or may be obtained with conditions that materially alter the expected return associated with the underlying projects;

- We may face opposition to our planned growth projects from environmental groups, landowners, local groups and other advocates, including lawsuits or other actions designed to disrupt or delay our planned projects;

- We may not be able to secure, or we may be significantly delayed in obtaining, all of the rights of way or other real property interests we need to complete such projects, or the costs we incur in order to obtain such rights of way or other interests may be greater than we anticipated;

- Despite the fact that we will expend significant amounts of capital during the construction phase of these projects, revenues associated with these organic growth projects will not materialize until the projects have been completed and placed into commercial service, and the amount of revenue generated from these projects could be significantly lower than anticipated for a variety of reasons;

- We may construct pipelines, facilities or other assets in anticipation of market demand that dissipates or market growth that never materializes;

- Due to unavailability or costs of materials, supplies, power, labor or equipment, the cost of completing these projects could turn out to be significantly higher than we budgeted and the time it takes to complete construction of these projects and place them into commercial service could be significantly longer than planned; and

- The completion or success of our projects may depend on the completion or success of third-party facilities over which we have no control.

As a result of these uncertainties, the anticipated benefits associated with our capital projects may not be achieved or could be delayed. In turn, this could negatively impact our cash flow and our ability to make or increase cash distributions to our partners.

Our profitability depends on the volume of crude oil, refined product, natural gas and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our facilities, which can be negatively impacted by a variety of factors outside of our control.

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

During the latter half of 2014, benchmark crude oil prices declined significantly; as a result, many of the companies that produce oil and gas have announced that they are reducing capital expenditures for 2015. Such reduced expenditure levels, coupled with high decline rates for many horizontal wells in the shale resource plays, could lead to a significant slow-down in the rate of

Table of Contents

growth of North American production and possibly an overall reduction in production levels. Other factors that could adversely impact production include reduced capital market access, increased capital raising costs for producers or adverse governmental or regulatory action. In turn, such developments could lead to reduced throughput on our pipelines and at our other facilities, which, depending on the level of production declines, could have a material adverse effect on our business.

Also, except with respect to some of our recently constructed pipeline assets, third-party shippers generally do not have long-term contractual commitments to ship crude oil on our pipelines. A decision by a shipper to substantially reduce or cease to ship volumes of crude oil on our pipelines could cause a significant decline in our revenues.

To maintain the volumes of crude oil we purchase in connection with our operations, we must continue to contract for new supplies of crude oil to offset volumes lost because of reduced drilling activity by producers, natural declines in crude oil production from depleting wells or volumes lost to competitors. If production declines, competitors with under-utilized assets could impair our ability to secure additional supplies of crude oil.

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 is favorable to commercial strategies that are associated with storage capacity as it allows a party to simultaneously purchase crude oil 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) can have a positive impact on lease gathering margins because in certain circumstances 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 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.

A natural disaster, catastrophe, terrorist attack, process safety failure or other event, including attacks on our electronic and computer systems, could interrupt our operations and/or result in severe personal injury, property damage and environmental damage, which could have a material adverse effect on our financial position, results of operations and cash flows.

Some of our operations involve risks of personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes. The location of some of our assets and our customers assets in the U.S. Gulf Coast region makes them particularly vulnerable to hurricane or tropical storm risk. Our facilities and operations are also vulnerable to accidents caused by process safety failures, equipment failures or human error. In addition, 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. Terrorists may target our physical facilities and hackers may attack our electronic and computer systems.

If one or more of our facilities, including electronic and computer systems, or any facilities or businesses that deliver products, supplies or services to us or that we rely on in order to operate our business, are damaged by severe weather or any other disaster, accident, catastrophe, terrorist attack or event, our operations could be significantly interrupted. These interruptions could involve significant damage or injury to people, property or the environment, and repairs could take from a week or less for minor incidents to six months or more for major interruptions. Any such event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions to our partners and, accordingly, adversely affect our financial condition and the market price of our securities.

We may also suffer reputational damage as a result of a disaster, accident, catastrophe, terrorist attack or other such event. The occurrence of such an event, or a series of such events, especially if one or more of them occurs in a highly populated or sensitive area, could negatively impact public perception of our operations and/or make it more difficult for us to obtain the approvals, permits, licenses or real property interests we need in order to operate our assets or complete planned growth projects.

Table of Contents

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

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

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

Acquisitions involve 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 for which we are either not indemnified, or the indemnity is not from a credit-worthy party, 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 to our partners or meet our debt service requirements.

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 expansion capital projects. Acquisition transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets and operations. Our ability to fund our capital projects and make acquisitions depends on whether we can access the necessary financing to fund these activities. 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. In addition, a variety of factors beyond our control could impact the availability or cost of capital, including domestic or international economic conditions, increases in key benchmark interest rates and/or credit spreads, the adoption of new or amended banking or capital market laws or regulations, the re-pricing of market risks and volatility in capital and financial markets.

Due to these factors, we cannot be certain that funding for our capital needs will be available from bank credit arrangements or capital markets on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to implement our development plans, enhance our existing business, complete acquisitions and construction projects, take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations.

Table of Contents

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

We believe that, because of our strategic asset base and complementary business model, we will continue to benefit from swings in market prices and shifts in market structure during periods of volatility in the crude oil, NGL and natural gas markets. The extent to which we are able to capture that benefit, however, is subject to numerous risks and uncertainties, including whether we will be able to maintain an attractive credit rating and continue to receive open credit from our suppliers and trade counterparties. Our senior unsecured debt is currently rated as investment grade by Standard & Poor s and Moody s Investors Service. A downgrade by either of such rating agencies could increase our borrowing costs, reduce our borrowing capacity and cause our counterparties to reduce the amount of open credit we receive from them. This could negatively impact our ability to capitalize on market opportunities. 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, both in terms of 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 crude oil until the time we complete the sale of the crude oil.

We are exposed to the credit risk of our customers in the ordinary course of our business activities.

Risks of nonpayment and nonperformance by customers are a significant consideration in our business. Although we have credit risk management policies and procedures that are designed to mitigate and limit our exposure in this area, there can be no assurance that we have adequately assessed and managed the creditworthiness of our existing or future counterparties or that there will not be an unanticipated deterioration in their creditworthiness or unexpected instances of nonpayment or nonperformance, all of which could have an adverse impact on our cash flow and our ability to pay or increase our cash distributions to our partners.

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

In addition, our operations involve the risk of non-compliance with our risk policies. We have taken steps within our organization to implement processes and procedures designed to detect unauthorized trading; however, we can provide no assurance that these steps will detect and prevent all violations of our risk policies and procedures, particularly if deception, collusion or other intentional misconduct is involved.

Our operations are also subject to laws and regulations relating to protection of the environment and wildlife, operational safety, climate change and related matters that may expose us to significant costs and liabilities.

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons, including crude oil, NGL 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 and wildlife, operational safety, climate change 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. For example, the adoption of legislation or regulatory programs to reduce emissions of

Table of Contents

greenhouse gases, including cap and trade programs, could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. In addition, with respect to our railcar operations, the adoption of new regulations designed to enhance the overall safety of crude oil and natural gas liquids transportation by rail, including new regulations requiring that existing railcars be retrofitted or upgraded to improve integrity, could result in increased operating costs and potentially involve substantial capital expenditures. Also, the failure to comply with any such laws and regulations could 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, including the possibility that exemptions we currently qualify for may be modified or changed in ways that require us to incur significant additional compliance costs. Any such change or interpretation adverse to us could have a material adverse effect on our operations, revenues, expenses and profitability.

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

We currently devote substantial resources to comply with DOT-mandated pipeline integrity rules. The 2006 Pipeline Safety Act requires the DOT to issue regulations for certain pipelines that were not previously subject to regulation. The DOT regulations include requirements for the establishment of pipeline integrity management programs and for protection of high consequence areas where a pipeline leak or rupture could produce significant adverse consequences. We have also developed and implemented certain pipeline integrity measures that go beyond regulatory mandate. See Items 1 and 2 Business and Properties Regulation.

For 2015 and beyond, we will continue to focus on pipeline integrity management as a primary operational emphasis. In that regard, we have implemented programs intended to maintain the integrity of our assets, with a focus on risk reduction through testing, enhanced corrosion control, leak detection, and damage prevention. We have an internal review process pursuant to which we examine various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management mandate. The purpose of this process is to review the surrounding environment, condition and operating history of these pipeline and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, in addition to potential cost increases related to unanticipated regulatory changes or injunctive remedies resulting from regulatory agency enforcement actions, we may elect (as a result of our own internal initiatives) to spend substantial sums to ensure the integrity of and upgrade our pipeline systems to maintain environmental compliance and, in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines. We cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures but any such expenditures could be significant. See Item 3 Legal Proceedings Environmental.

Fluctuations in demand, which can be caused by a variety of factors outside of our control, can negatively affect our operating results.

Demand for crude oil and other hydrocarbon products we handle is dependent upon a variety of factors, including price, the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation, including climate change regulations, and technological advances in fuel economy and energy generation devices. For example, the adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could increase the cost of consuming crude oil and other hydrocarbon products, thereby causing a reduction in the demand for such products. 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 those caused by refinery downtime or shutdowns, 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.

Table of Contents

Fluctuations in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products, increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL products, particularly propane, or other reasons, could result in a decline in the volume of NGL products we handle or a reduction of the fees we charge for our services. Also, increased supply of NGL products could reduce the value of NGL we handle and reduce the margins realized by us.

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

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 systems may reduce the amount of cash we generate.

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

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

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

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

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

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

The FTC, the FERC and the CFTC 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, NGL or other energy commodities, and any related transportation and/or hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Additionally, to the extent that we enter into transportation contracts with natural gas pipelines that are subject to FERC regulation, we are subject to FERC requirements related to the use of such capacity. Any failure on our part to comply with the regulations and policies of the FERC, the FTC or the CFTC 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.

Table of Contents

The enactment and implementation of derivatives legislation could have an adverse impact on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business and increase the working capital requirement to conduct these hedging activities.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd Frank Act), enacted on July 21, 2010, established federal oversight and regulation of derivative markets and entities, such as us, that participate in those markets. The Dodd Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for, or linked to, certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing, and the associated rules could also require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption from such requirements. We do not utilize credit default swaps and we qualify and expect to continue to qualify for the end-user exception from the mandatory clearing requirements for swaps entered into to hedge our interest rate risks. Should the CFTC designate commodity derivatives for mandatory clearing, we would expect to qualify for an end-user exception from the mandatory clearing requirements for swaps entered into to hedge our commodity price risk. However, the majority of our financial derivative transactions used for hedging commodity price risks are currently executed and cleared over exchanges that require the posting of margin or letters of credit based on initial and variation margin requirements. Pursuant to the Dodd Frank Act, however, the CFTC or federal banking regulators may require the posting of collateral with respect to uncleared interest rate and commodity derivative transactions.

Posting of additional cash margin or collateral could affect our liquidity (defined as unrestricted cash on hand plus available capacity under our credit facilities) and reduce our ability to use cash for capital expenditures or other partnership purposes. A requirement to post additional cash margin or collateral could therefore reduce our ability to execute hedges necessary to reduce commodity price exposures and protect cash flows. We could be at risk for reduced liquidity if the CFTC adopts rules and definitions that require companies, such as ours, to post collateral for our uncleared derivative hedging activities. The proposed margin rules for uncleared swaps are not yet final and, therefore, the impact of such rules on us is uncertain at this time.

Even if we ourselves are not required to post additional cash margin or collateral for our derivative contracts, the banks and other derivatives dealers who are our contractual counterparties will be required to comply with other new requirements under the Dodd Frank Act and related rules. The costs of such compliance may be passed on to customers such as ourselves, thus decreasing the benefits to us of hedging transactions or reducing our profitability. In addition, implementation of the Dodd Frank Act and related rules and regulations could reduce the overall liquidity and depth of the markets for financial and other derivatives we utilize in connection with our business, which could expose us to additional risks or limit the opportunities we are able to capture by limiting the extent to which we are able to execute our hedging strategies.

Finally, the Dodd Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. Our financial results could be adversely affected if a consequence of the Dodd Frank Act and implementing regulations is lower commodity prices.

The full impact of the Dodd Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd Frank Act and regulations implementing the Dodd Frank Act, our results of operations may become more volatile and our cash flows may be less predictable. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

Table of Contents

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from unconventional geological formations. Recent advances in hydraulic fracturing techniques have resulted in significant increases in crude oil and natural gas production in many basins in the United States and Canada. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production, and it is typically regulated by state and provincial oil and gas commissions. We do not perform hydraulic fracturing, but many of the producers using our pipelines do. Hydraulic fracturing has been subject to increased scrutiny due to public concerns that it could result in contamination of drinking water supplies, and there have been a variety of legislative and regulatory proposals to prohibit, restrict, or more closely regulate various forms of hydraulic fracturing. Any legislation or regulatory initiatives that curtail hydraulic fracturing could reduce the production of crude oil and natural gas in the United States or Canada, and could thereby reduce demand for our transportation, terminalling and storage services as well as our supply and logistics services.

We may not be able to compete effectively in our transportation, facilities and supply and logistics activities, and our business is subject to the risk of a capacity overbuild of midstream energy infrastructure in the areas where we operate.

We face competition in all aspects of our business and can give no assurances that we will be able to compete effectively against our competitors. In general, competition comes from a wide variety of players in a wide variety of contexts, including new entrants and existing players and in connection with day-to-day business, expansion capital projects, acquisitions and joint venture activities. Some of our competitors have capital resources many times greater than ours and control greater supplies of crude oil, natural gas or NGL.

A significant driver of competition in some of the markets where we operate (including, for example, the Eagle Ford, Permian Basin, and Rockies/Bakken areas) is the rapid development of new midstream energy infrastructure capacity driven by the combination of (i) significant increases in oil and gas production and development in the applicable production areas, both actual and anticipated, (ii) relatively low barriers to entry and (iii) generally widespread access to relatively low cost capital. While this environment presents opportunities for us, we are also exposed to the risk that these areas become overbuilt, resulting in an excess of midstream energy infrastructure capacity. Most midstream projects require several years of lead time to develop and companies like us that develop such projects are exposed (to varying degrees depending on the contractual arrangements that underpin specific projects) to the risk that expectations for oil and gas development in the particular area may not be realized or that too much capacity is developed relative to the demand for services that ultimately materializes. In addition, as an established player in some markets, we also face competition from aggressive new entrants to the market that are willing to provide services at a discount in order to establish relationships and gain a foothold in the market. If we experience a significant capacity overbuild in one or more of the areas where we operate, it could have a significant adverse impact on our financial position, cash flows and ability to pay or increase distributions to our unitholders.

With respect to our crude oil activities, our competitors include other crude oil pipelines, the major integrated oil companies, their marketing affiliates, refiners, industrial companies, independent gatherers, investment banks, brokers and marketers of widely varying sizes, financial resources and experience. We compete against these companies on the basis of many factors, including geographic proximity to production areas, market access, rates, terms of service, connection costs and other factors.

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. Our natural gas storage facilities compete with several other storage providers, including regional storage facilities and utilities. Certain pipeline companies have existing storage facilities connected to their systems that compete with some of our facilities.

With regard to our NGL operations, we compete with large oil, natural gas and natural gas liquids companies that may, relative to us, have greater financial resources and access to supplies of natural gas and NGL. The principal elements of competition are rates, processing fees (e.g., extraction premiums) paid to the owners or aggregators of natural gas to be processed, geographic proximity to the natural gas or NGL mix, available processing and fractionation capacity, transportation alternatives and their associated costs, and access to end user markets.

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

Over the last several years, as the scale and scope of our business activities has expanded, the breadth and depth of available insurance markets has contracted. As a result of these factors and other market conditions, premiums and deductibles for certain insurance policies has increased substantially. Accordingly, we can give no assurance that we will be able to maintain adequate insurance in the future at rates or on other terms we consider commercially reasonable. In addition, although we believe that we currently maintain adequate insurance coverage, insurance will not cover many types of interruptions or events that might occur and

Table of Contents

will not cover all risks associated with our operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur. The occurrence of a significant event, the consequences of which are either not covered by insurance or not fully insured, or a significant delay in the payment of a major insurance claim, could materially and adversely affect our financial position, results of operations and cash flows.

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, 2014, our consolidated debt outstanding was over $10 billion, consisting of approximately $8.8 billion principal amount of long-term debt (including senior notes) and approximately $1.3 billion of short-term borrowings (including current maturities of senior notes). As of December 31, 2014, we had approximately $2.6 billion of liquidity available, including cash and cash equivalents and available borrowing capacity under our senior unsecured revolving credit facility and our senior secured hedged inventory facility, subject to continued covenant compliance.

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 Agreements, Commercial Paper Program and Indentures.

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

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

As of December 31, 2014, we had over $10 billion of consolidated debt, of which approximately $9.3 billion was at fixed interest rates and approximately $734 million was at variable interest rates. We are exposed to market risk due to the short-term nature of our commercial paper borrowings and the floating interest rates on our credit facilities. Our results of operations, cash flows and financial position could be adversely affected by significant increases in interest rates above current levels. Additionally, increases in interest rates could adversely affect our supply and logistics segment results by increasing interest costs associated with the storage of hedged crude oil and NGL 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.

Table of Contents

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

Because we are a U.S. dollar reporting company and also conduct operations in Canada, we are exposed to currency fluctuations and exchange rate risks that may adversely affect the U.S. dollar value of our earnings, cash flow and partners capital under applicable accounting rules. For example, as the U.S. dollar appreciates against the Canadian dollar, the U.S. dollar value of our Canadian dollar denominated earnings is reduced for U.S. reporting purposes.

An impairment of goodwill, intangibles or certain investments could reduce our earnings.

At December 31, 2014, we had approximately $2.5 billion of goodwill, $366 million of net intangibles and $1.7 billion of investments accounted for under the equity method of accounting. 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. GAAP requires us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. GAAP requires that we amortize finite-lived intangibles over their estimated useful lives and test all of our intangibles for impairment when events or circumstances indicate the carrying value may not be recoverable. In addition, certain of our investments are accounted for under the equity method of accounting. GAAP requires that investments accounted for under the equity method be tested for impairment based on whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. If we were to determine that any of our goodwill, intangibles or equity method investments were impaired, we would be required to take an immediate charge to earnings, which could adversely impact our operating results, with a corresponding reduction of partners capital and increase in balance sheet leverage as measured by debt-to-total capitalization.

Rail and marine transportation of crude oil have inherent operating risks.

Our supply and logistics operations include purchasing crude oil that is carried on railcars, tankers or barges. Such cargos are at risk of being damaged or lost because of events such as derailment, marine disaster, inclement weather, mechanical failures, grounding or collision, fire, explosion, environmental accidents, piracy, terrorism and political instability. Such occurrences could result in death or injury to persons, loss of property or environmental damage, delays in the delivery of cargo, loss of revenues, termination of 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.

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 receives waterborne crude oil through dock facilities operated by a third party in the Port of Long Beach. If at any time our access to this dock was denied, and if access to an alternative dock could not be arranged, the volume of crude oil that we presently receive from our customers in the Los Angeles basin may be reduced, which could result in a reduction of facilities segment revenue and cash flow.

Non-utilization of certain assets, such as our leased railcars, could significantly reduce our profitability due to fixed costs incurred to obtain the right to use such assets.

From time to time in connection with our business, we may lease or otherwise secure the right to use certain third party assets (such as railcars, trucks, barges, ships, pipeline capacity, storage capacity and other similar assets) with the expectation that the revenues we generate through the use of such assets will be greater than the fixed costs we incur pursuant to the applicable leases or other arrangements. However, when such assets are not utilized or are under-utilized, our profitability could be negatively impacted because the revenues we earn are either non-existent or reduced, but we remain obligated to continue paying any applicable fixed charges, in addition to the potential of incurring other costs attributable to the non-utilization of such assets. For example, in connection with our rail operations, we lease substantially all of our railcars, typically pursuant to multi-year leases that obligate us to pay the applicable lease rate without regard to utilization. If business conditions are such that a portion of our rail fleet is not utilized for any period of time due to reduced demand for the services they provide, we will still be obligated to pay the applicable fixed lease rate for such railcars. In addition, during the period of time that we are not utilizing such railcars, we will incur incremental costs associated with the cost of storing such railcars and will continue to incur costs for maintenance and upkeep. Non-utilization of our leased railcars and other similar assets in connection with our business could have a significant negative impact on our profitability and cash flows.

Table of Contents

For various operating and commercial reasons, we may not be able to perform all of our obligations under our contracts, which could lead to increased costs and negatively impact our financial results.

Various operational and commercial factors could result in an inability on our part to satisfy our contractual commitments and obligations. For example, in connection with our provision of firm storage services and hub services to our natural gas storage customers, we enter into contracts that obligate us to honor our customers requests to inject gas into our storage facilities, withdraw gas from our facilities and wheel gas through our facilities, in each case subject to volume, timing and other limitations set forth in such contracts. The following factors could adversely impact our ability to perform our obligations under these contracts:

- a failure on the part of our storage facilities to perform as we expect them to, whether due to malfunction of equipment or facilities or realization of other operational risks;
- the operating pressure of our storage facilities (affected in varying degree, depending on the type of storage cavern, by total volume of working and base gas, and temperature);
- a variety of commercial decisions we make from time to time in connection with the management and operation of our storage facilities. Examples include, without limitation, decisions with respect to matters such as (i) the aggregate amount of commitments we are willing to make with respect to wheeling, injection, and withdrawal services, which could exceed our capabilities at any given time for various reasons, (ii) the timing of scheduled and unplanned maintenance or repairs, which can impact equipment availability and capacity, (iii) the schedule for and rate at which we conduct opportunistic leaching activities at our facilities in connection with the expansion of existing salt caverns, which can impact the amount of storage capacity we have available to satisfy our customers requests, (iv) the timing and aggregate volume of any base gas park and/or loan transactions we consummate, which can directly affect the operating pressure of our storage facilities and (v) the amount of compression capacity and other gas handling equipment that we install at our facilities to support gas wheeling, injection and withdrawal activities; and
- adverse operating conditions due to hurricanes, extreme weather events or conditions, and operational problems or issues with third-party pipelines, storage or production facilities.

Although we manage and monitor all of these various factors in connection with the ongoing operation of our natural gas storage facilities with the goal of performing all of our contractual commitments and obligations and optimizing our revenue, one or more of the above factors may adversely impact our ability to satisfy our injection, withdrawal or wheeling obligations under our storage contracts. In such event, we may be liable to our customers for losses or damages they suffer and/or we may need to incur costs or expenses in order to permit us to satisfy our obligations.

Risks Inherent in an Investment in Us

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 AAP Management Units). 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 may have the following effects:

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

- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Our general partner has a limited call right that may require unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own 80% or more of the common units, the general partner will have the right, but not the obligation, which it may assign to any of its affiliates, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price generally equal to the then current market price of the common units. As a result, unitholders may be required to sell their common units at a time when they may not desire to sell them and/or at a price that is less than the price they would like to receive. They may also incur a tax liability upon a sale of their common units.

Unitholders may not have limited liability if a court finds that unitholder actions constitute control of our business and unitholders may have liability to repay distributions under certain circumstances.

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.

Table of Contents

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.

Furthermore, under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount.

Conflicts of interest could arise among our general partner and us or the unitholders.

These conflicts may include the following:

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

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

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

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

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

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

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

Risks Related to an Investment in Our Debt Securities

The right to receive payments on our outstanding debt securities is unsecured and will be effectively subordinated to our existing and future secured indebtedness and will be structurally subordinated as to any existing and future indebtedness and other obligations of our subsidiaries, other than subsidiaries that may guarantee our debt securities in the future.

Our debt securities are effectively subordinated to claims of our secured creditors and to any existing and future indebtedness and other obligations of our subsidiaries, including trade payables, other than subsidiaries that may guarantee our debt securities in the future. In the event of the insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up of the business of a subsidiary, other than a subsidiary that may guarantee our debt securities in the future, 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 our 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, 2014, our total outstanding long-term debt was approximately $8.8 billion, and our total outstanding short-term debt (including current maturities of senior notes) was approximately $1.3 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 and other debt instruments may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

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 our debt securities 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 our debt securities will likely need to be refinanced at maturity in whole or in part. 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 a portion of our debt or sell assets. We can give no assurance that we would be able to refinance our existing indebtedness or sell assets on terms that are commercially reasonable.

Our leverage may adversely affect our ability to fund future working capital, capital expenditures and other general partnership requirements, future acquisition, construction or development activities, or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness. Our leverage may also make our results of operations more susceptible to adverse economic and industry conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

The ability to transfer our debt securities may be limited by the absence of an organized 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, continuation 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 our 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 our debt securities, or to repurchase our debt securities upon the occurrence of a change of control, we may be required to adopt one or more alternatives, such as a refinancing of our debt securities. We can give no assurance that we would be able to refinance our debt securities.

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

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

Table of Contents

- 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 U.S. federal income tax purposes, as well as our not being subject to a material amount of additional entity-level taxation by individual states. If the Internal Revenue Service (IRS) were to treat us as a corporation for federal income tax purposes or if we become subject to 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.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. A publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless it satisfies a qualifying income requirement, as defined in Section 7704 of the Internal Revenue Code of 1986, as amended. Based on our current operations we believe that we are treated as a partnership rather than a corporation for such purposes; however, a change in our business could cause us to be treated as a corporation for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

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

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal income tax purposes, our minimum quarterly distribution and target distribution amounts will be adjusted downward by a percentage that is based on the applicable entity-level tax rate, including both federal and state tax burdens. Although it is impossible to make an accurate assessment of the impact on us without the specific details of any such new law or modification, in such event, it is likely the overall amount of cash available for distribution by the partnership will decline and, due to the structure of our incentive distribution rights and the distribution provisions of our partnership agreement, our common unitholders will likely bear a disproportionately larger percentage of such reduction as compared to the holder of our incentive distribution rights.

The tax treatment of publicly traded partnerships or 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 publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, the Obama administration s budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. From time to time, members of Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. If successful, the Obama administration s proposal or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly-traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

Table of Contents

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

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

The IRS has made no determination as to our status as a partnership for federal income tax purposes or as to any other matter affecting us. The IRS or CRA may adopt positions that differ from the positions we take or challenge the inter-country allocations we make. 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 of the positions we take. Any contest with the IRS or CRA may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS or CRA and any incremental taxes required to be paid 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.

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

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

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

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

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

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 non-U.S. taxes and return filing requirements in states and jurisdictions where they do not live as a result of investing in our units.

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

We have adopted certain valuation methodologies in determining unitholder s allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations, and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our respective assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our respective assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the amount, character, and timing 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 the subject of a securities loan (e.g., a loan 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 are no specific rules governing the federal income tax consequences of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, 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 may 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.

Table of Contents

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

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

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

None.

Item 3. ***Legal Proceedings***

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

Environmental

General. Although we believe that our efforts to enhance our leak prevention and detection capabilities have produced positive results, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline, rail and storage operations. These releases can result from unpredictable man-made or natural forces and may reach surface water bodies, groundwater aquifers or other sensitive environments. Whether current or past, damages and liabilities associated with any such releases from our assets may substantially affect our business.

At December 31, 2014, our estimated undiscounted reserve for environmental liabilities totaled $82 million, of which $13 million was classified as short-term and $69 million was classified as long-term. At December 31, 2013, our estimated undiscounted reserve for environmental liabilities totaled $93 million, of which $11 million was classified as short-term and $82 million was classified as long-term. The short- and long-term environmental liabilities referenced above are reflected in Accounts payable and accrued liabilities and Other long-term liabilities and deferred credits, respectively, on our Consolidated Balance Sheets. At December 31, 2014 and 2013, we had recorded receivables totaling $8 million and $10 million, respectively, for amounts probable of recovery under insurance and from third parties under indemnification agreements, which are predominantly reflected in Trade accounts receivable and other receivables, net on our Consolidated Balance Sheets.

In some cases, the actual cash expenditures may not occur for three years or longer. Our estimates used in these reserves are based on information currently available to us and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional liabilities. 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.

Bay Springs Pipeline Release. During February 2013, we experienced a crude oil release of approximately 120 barrels on a portion of one of our pipelines near Bay Springs, Mississippi. Most of the released crude oil was contained within our pipeline right of way, but some of the released crude oil entered a nearby waterway where it was contained with booms. The EPA has issued an administrative order requiring us to take various actions in response to the release, including remediation, reporting and other actions. We have satisfied the requirements of the administrative order; however, we may be subjected to a civil penalty. The aggregate cost to clean up and remediate the site was approximately $6 million.

Table of Contents

Kemp River Pipeline Releases. During May and June 2013, two separate releases were discovered on our Kemp River pipeline in Northern Alberta, Canada that, in the aggregate, resulted in the release of approximately 700 barrels of condensate and light crude oil. Clean-up and remediation activities are being conducted in cooperation with the applicable regulatory agencies. Final investigation by the AER is not complete. To date, no charges, fines or penalties have been assessed against PMC with respect to these releases; however, it is possible that fines or penalties may be assessed against PMC in the future. We estimate that the aggregate clean-up and remediation costs associated with these releases will be approximately $15 million. Through December 31, 2014, we spent approximately $9 million in connection with clean-up and remediation activities.

National Energy Board Audit. In the third quarter of 2014, the National Energy Board (NEB) of Canada notified PMC that various corrective actions from a 2010 audit had not been completed to the satisfaction of the NEB. The NEB initiated a process to assess PMC s approach to compliance with the NEB s Onshore Pipeline Regulations, which process resulted in the issuance by the NEB of an order on January 15, 2015 that imposed six conditions on PMC designed to enhance PMC s ability to operate its pipelines in a manner that protects the public and the environment. The conditions include the filing of certain safety critical tasks, controls and programs with the NEB, external audits of certain PMC programs and systems, and periodic update meetings with NEB staff regarding the status and progress of corrective actions. In early February 2015, the NEB imposed a penalty on PMC of $76,000 CAD related to these issues. It is possible that additional fines and penalties may be assessed against PMC in the future related to this matter.

Insurance

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

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

Our assessment of the current availability of coverage and associated rates for hurricane insurance has led us to the decision to self-insure this risk. This decision does not affect our third-party liability insurance, which still covers hurricane-related liability claims and which we have maintained at our historic coverage levels. In addition, although we believe that we have established adequate reserves to the extent such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

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

Not applicable.

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 18, 2015, the closing market price for our common units was $50.73 per unit and there were approximately 236,000 record holders and beneficial owners (held in street name). As of February 18, 2015, there were 376,241,697 common units outstanding.

A two-for-one split of our common units was completed on October 1, 2012. The effect of the two-for one split has been retroactively applied to all unit and per-unit amounts presented in this Form 10-K. In addition, our partnership agreement was amended to modify certain definitions related to target distribution amounts and minimum distribution amounts to reflect the unit split.

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)	
2014						
4th Quarter	$	59.75	$	43.61	$	0.6750
3rd Quarter	$	61.09	$	55.98	$	0.6600
2nd Quarter	$	60.05	$	54.54	$	0.6450
1st Quarter	$	55.30	$	49.25	$	0.6300
2013						
4th Quarter	$	53.74	$	47.26	$	0.6150
3rd Quarter	$	57.72	$	48.86	$	0.6000
2nd Quarter	$	59.52	$	50.15	$	0.5875
1st Quarter	$	57.17	$	45.95	$	0.5750

(1) Cash distributions associated with the quarter presented. These distributions were declared and paid in the following calendar quarter. See the Cash Distribution Policy section below for a discussion of our policy regarding distribution payments.

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

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.

Cash Distribution Policy

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

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

Table of Contents

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 adjustments discussed below, to 15% of amounts we distribute in excess of $0.2250 per unit, 25% of the amounts we distribute in excess of $0.2475 per unit and 50% of amounts we distribute in excess of $0.3375 per unit.

Although not required to do so, in response to past requests by our management in connection with our acquisition activities, our general partner has, from time to time, agreed to reduce the amounts due to it as incentive distributions. Such modifications were implemented with a view toward enhancing our competitiveness for such acquisitions and managing the overall cost of equity capital while achieving an appropriate balance between short-term and long-term accretion to our limited partners and the holders of our general partner interest and IDRs. During 2014 and 2013, our general partner s incentive distributions were reduced by approximately $23 million and $15 million, respectively. These reductions were agreed to in connection with our BP NGL Acquisition and the PNG Merger. In addition, our general partner has agreed to reduce the amount of its incentive distribution by $5.5 million per quarter during 2015, $5.0 million per quarter in 2016 and $3.75 million per quarter thereafter. See Note 3 to our Consolidated Financial Statements for further discussion of the BP NGL Acquisition. See Note 11 to our Consolidated Financial Statements for further discussion of the PNG Merger.

During 2014, we paid $473 million to our general partner, including $454 million of incentive distributions, net of reductions of approximately $23 million. Additionally, on February 13, 2015, we paid a quarterly distribution of $0.6750 per limited partner unit applicable to the fourth quarter of 2014, and in connection therewith, approximately $136 million was paid to our general partner, including approximately $131 million of incentive distributions, net of reductions of $5.5 million. 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 Agreements, Commercial Paper Program and Indentures.

Issuer Purchases of Equity Securities

We did not repurchase any of our common units during the fourth quarter of 2014, and we do not have any announced or existing plans to repurchase any of our common units other than potential repurchases consistent with past practice in providing units for relatively small vestings of phantom units under our long-term incentive plans (LTIP).

Table of Contents

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

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2014, 2013, 2012, 2011 and 2010 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. See Note 3 to our Consolidated Financial Statements for a discussion of our acquisitions.

	Year Ended December 31, 2014	2013	2012	2011	2010
	(in millions, except per unit data)				
Statement of operations data:					
Total revenues	$ 43,464	$ 42,249	$ 37,797	$ 34,275	$ 25,893
Net income	$ 1,386	$ 1,391	$ 1,127	$ 994	$ 514
Net income attributable to PAA	$ 1,384	$ 1,361	$ 1,094	$ 966	$ 505
Per unit data:					
Basic net income per limited partner unit	$ 2.39	$ 2.82	$ 2.41	$ 2.46	$ 1.21
Diluted net income per limited partner unit	$ 2.38	$ 2.80	$ 2.40	$ 2.44	$ 1.20
Declared distributions per limited partner unit (1)	$ 2.55	$ 2.33	$ 2.11	$ 1.95	$ 1.88
Balance sheet data (at end of period):					
Total assets	$ 22,256	$ 20,360	$ 19,235	$ 15,381	$ 13,703
Long-term debt	$ 8,762	$ 6,715	$ 6,320	$ 4,520	$ 4,631
Total debt	$ 10,049	$ 7,828	$ 7,406	$ 5,199	$ 5,957
Partners capital	$ 8,191	$ 7,703	$ 7,146	$ 5,974	$ 4,573
Other data:					
Net cash provided by operating activities	$ 2,004	$ 1,954	$ 1,240	$ 2,365	$ 259
Net cash used in investing activities	$ (3,296)	$ (1,653)	$ (3,392)	$ (2,020)	$ (851)
Net cash provided by/(used in) financing activities	$ 1,657	$ (281)	$ 2,151	$ (345)	$ 604
Capital expenditures:					
Acquisition capital	$ 1,099	$ 19	$ 2,286	$ 1,404	$ 407
Expansion capital	$ 2,026	$ 1,622	$ 1,185	$ 531	$ 355
Maintenance capital	$ 224	$ 176	$ 170	$ 120	$ 93

Table of Contents

	Year Ended December 31,				
	2014	2013	2012	2011	2010
Volumes (2)(3)					
Transportation segment (average daily volumes in thousands of barrels per day):					
Tariff activities	3,952	3,595	3,373	2,942	2,889
Trucking	127	117	106	105	97
Transportation segment total	4,079	3,712	3,479	3,047	2,986
Facilities segment:					
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	95	94	90	70	61
Rail load / unload volumes (average volumes in thousands of barrels per day)	231	221			
Natural gas storage (average monthly working capacity in billions of cubic feet)	97	96	84	71	47
NGL fractionation (average volumes in thousands of barrels per day)	96	96	79	14	14
Facilities segment total (average monthly volumes in millions of barrels)	121	120	106	82	70
Supply and Logistics segment (average daily volumes in thousands of barrels per day):					
Crude oil lease gathering purchases	949	859	818	742	620
NGL sales	208	215	182	103	96
Waterborne cargos		4	3	21	68
Supply and Logistics segment total	1,157	1,078	1,003	866	784

(1) Represents cash distributions declared and paid during the year presented. Our general partner is entitled, directly or indirectly, to receive 2% proportional distributions, as well as incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. See Note 11 to our Consolidated Financial Statements for further discussion regarding our distributions.

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

(3) Facilities segment total is calculated as the sum of: (i) crude oil, refined products and NGL terminalling and storage capacity; (ii) rail load and unload volumes multiplied by the number of days in the year and divided by the number of months in the year; (iii) natural gas storage working capacity divided by 6 to account for the 6:1 thousand cubic feet (mcf) of natural gas to crude British thermal unit (Btu) equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iv) NGL fractionation volumes multiplied by the number of days in the year and divided by the number of months in the year.

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

Introduction

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

Our discussion and analysis includes the following:

- Executive Summary
- Company Overview
- Overview of Operating Results, Capital Investments and Other Significant Activities
- Acquisitions and Capital Projects
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements
- Results of Operations
- Outlook

- Liquidity and Capital Resources

Executive Summary

Company Overview

We own and operate midstream energy infrastructure and provide logistics services for crude oil, NGL, natural gas and refined products. The term NGL includes ethane and natural gasoline products as well as products commonly referred to as liquefied petroleum gas (LPG) such as propane and butane. When used in this Form 10-K, NGL refers to all NGL products including LPG. We own an extensive network of pipeline transportation, terminalling, storage, and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries and are managed through three operating segments: Transportation, Facilities and Supply and Logistics. See Results of Operations Analysis of Operating Segments for further discussion.

Overview of Operating Results, Capital Investments and Other Significant Activities

Primarily as a result of advances in drilling and completion techniques and their application to a number of large-scale shale and resource plays occurring contemporaneously with attractive crude oil and liquids prices, U.S. crude oil and liquids production over the last several years increased rapidly in multiple regions in the lower 48 states. Additionally, the crude oil market periodically experienced high levels of volatility in location and quality differentials as a result of the confluence of regional infrastructure constraints in North America, rapid and unexpected changes in crude oil qualities, international supply issues and regional downstream operating issues.

During 2013 and 2014, these market conditions had a positive impact on our profitability as our business strategy and asset base positioned us to capitalize on opportunities created by the volatile environment. In 2014, we recognized net income attributable to PAA of $1.384 billion as compared to net income attributable to PAA of $1.361 billion recognized in 2013. The year-over-year change in operating results was due to growth in our fee-based Transportation segment partially offset by less favorable results from our Supply and Logistics and Facilities segments (see further discussion of our segment operating results in the following sections). Net income attributable to PAA for 2014 was also impacted by:

Table of Contents

- Higher depreciation and amortization expense and interest expense associated with our growing asset base and related financing activities;
- Increased income tax expense resulting from higher year-over-year earnings from our taxable Canadian operations; and
- Decreased net income attributable to noncontrolling interests due to our completion of the PNG Merger in 2013.

We have continued to invest in midstream infrastructure projects to address the need for additional pipeline takeaway capacity and to address associated logistical challenges, resulting in the execution of a $2.0 billion capital program during 2014. We also completed the acquisition of a 50% interest in BridgeTex in November 2014 for $1.088 billion. The majority of the capital spent in 2014 will contribute to growth in our fee-based Transportation and Facilities segments in future years. In addition, during the year, we paid $1.4 billion of cash distributions to our limited partners and general partner.

We funded our 2014 capital activities with the issuance of approximately 15.4 million common units under our continuous offering program for net proceeds of $866 million, and the completion of multiple senior notes offerings for net proceeds of approximately $2.6 billion.

During late 2014 and early 2015, crude oil and NGL prices decreased meaningfully, which resulted in significant reductions in the outlook for producer drilling activities in 2015. See Outlook for a discussion of how such developments may impact our business.

Acquisitions and Capital Projects

We completed a number of acquisitions and capital projects in 2014, 2013 and 2012 that have impacted our results of operations. The following table summarizes our expenditures for acquisition capital, expansion capital and maintenance capital for the periods indicated (in millions):

	Year Ended December 31,		
	2014	**2013**	**2012**
Acquisition capital (1) (2)	$ 1,099	$ 19	$ 2,286
Expansion capital (3)	2,026	1,622	1,185
Maintenance capital (3)	224	176	170
	$ 3,349	$ 1,817	$ 3,641

(1) Includes our acquisition for $1.088 billion of a 50% interest in BridgeTex. We account for our interest in BridgeTex under the equity method of accounting. Acquisitions of initial investments in unconsolidated entities are included in Acquisition capital. Additional subsequent investments in unconsolidated entities related to expansion projects of such entities are recognized in Expansion capital.

(2) Excludes the PNG Merger completed on December 31, 2013, as we historically consolidated PNG into our financial statements for financial reporting purposes in accordance with GAAP. As consideration for the PNG Merger, we issued approximately 14.7 million PAA common units with a value of approximately $760 million. See Note 11 to our Consolidated Financial Statements for further discussion of the PNG Merger.

(3) Capital expenditures made to expand the existing operating and/or earnings capacity of our assets are classified as expansion capital. Capital expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets are classified as maintenance capital.

Table of Contents

Acquisitions

Acquisitions are financed using a combination of equity and debt, including borrowings under our commercial paper program or credit facilities and the issuance of senior notes. Businesses acquired impact our results of operations commencing on the closing date of each acquisition. Our acquisition and capital expansion activities are discussed further in Liquidity and Capital Resources and in Note 3 to our Consolidated Financial Statements. Information regarding acquisitions completed in 2014, 2013 and 2012 is set forth in the table below (in millions):

Acquisition	**Effective Date**		**Acquisition Price**	**Operating Segment**
BridgeTex Acquisition (50% interest) (1)	11/14/2014	$	1,088	Transportation
Other	Various		11	Facilities
2014 Total		$	1,099	
2013 Total (2)	09/01/2013	$	19	Transportation
BP NGL Acquisition (3)	04/01/2012	$	1,633	Transportation, Facilities and Supply and Logistics
US Development Group Crude Oil Rail Terminals	12/13/2012		503	Facilities
Other	Various		150	Transportation, Facilities and Supply and Logistics
2012 Total		$	2,286	

(1) We account for our 50% interest in BridgeTex under the equity method of accounting. See Note 8 to our Consolidated Financial Statements for further discussion of our equity method investments.

(2) Excludes the PNG Merger completed on December 31, 2013, as we historically consolidated PNG into our financial statements for financial reporting purposes in accordance with GAAP. As consideration for the PNG Merger, we issued approximately 14.7 million PAA common units with a value of approximately $760 million. See Note 11 to our Consolidated Financial Statements for further discussion of the PNG Merger.

(3) Total BP NGL Acquisition purchase price was approximately $1.683 billion. A cash deposit of $50 million was paid during 2011.

Table of Contents

Expansion Capital Projects

Our 2014 projects primarily included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2014, 2013 and 2012 projects (in millions):

Projects	2014	2013	2012
Permian Basin Area Projects (1)	$ 378	$ 59	$ 91
Cactus Pipeline (1)	350	64	
Rail Terminal Projects (1) (4)	239	149	59
Fort Saskatchewan Facility Projects / NGL Line (1)	142	73	
Eagle Ford JV Project (1) (3)	117	60	132
Western Oklahoma Pipeline	80	50	
Mississippian Lime Pipeline	58	163	54
White Cliffs Expansion (5)	41	73	1
Line 63 Reactivation (1)	32	12	
Diamond Pipeline (1)	29	3	
Pascagoula Pipeline	26	125	13
St. James Terminal Expansions	25	51	46
Cushing Terminal Expansions (1)	13	38	31
Eagle Ford Area Projects (1) (2)	10	86	88
Rainbow II Pipeline	3	124	79
Other projects	483	492	591
Total	$ 2,026	$ 1,622	$ 1,185

(1) These projects will continue into 2015. See Liquidity and Capital Resources Acquisitions, Capital Expenditures and Distributions Paid to Our Unitholders, General Partner and Noncontrolling Interests 2015 Capital Projects.

(2) Includes pipeline, tankage and condensate stabilization.

(3) Includes net expenditures associated with the formation of Eagle Ford Pipeline LLC in 2012, as well as subsequent contributions related to our 50% interest.

(4) Includes Bakersfield, CA; Carr, CO; Manitou, ND; Van Hook, ND; Yorktown, VA; and Kerrobert, Canada rail projects.

(5) Represents contributions related to our 35.7% investment interest in the White Cliffs Pipeline.

The overall increase in our expansion capital expenditures over the periods presented was primarily driven by our investment in midstream infrastructure projects to address the need for additional takeaway capacity in regions impacted by the increase in crude oil and liquids-rich gas production growth in North America. A majority of the expansion capital spent in the years presented was invested in our fee-based Transportation and Facilities segments.

We expect to spend approximately $1.85 billion for expansion capital in 2015. See Liquidity and Capital Resources Acquisitions, Capital Expenditures and Distributions Paid to Our Unitholders, General Partner and Noncontrolling Interests 2015 Capital Projects for additional information.

Critical Accounting Policies and Estimates

Critical Accounting Policies

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

Critical Accounting Estimates

The preparation of financial statements in conformity with GAAP and rules and regulations of the United States Securities and Exchange Commission (SEC) requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, as well as the disclosure of contingent assets and liabilities, at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Although we believe these estimates are reasonable, actual results could differ from these estimates. On a regular basis, we evaluate our assumptions, judgments and estimates. We also discuss our critical accounting policies and estimates with the Audit Committee of the Board of Directors.

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

Purchase and Sales Accruals. We routinely make accruals based on estimates for certain components of our revenues and cost of sales due to the timing of compiling billing information, receiving third-party information and reconciling our records with those of third parties. Where applicable, these accruals are based on nominated volumes expected to be purchased, transported and subsequently sold. Uncertainties involved in these estimates include levels of production at the wellhead, access to certain qualities of crude oil, pipeline capacities and delivery times, utilization of truck fleets to transport volumes to their destinations, weather, market conditions and other forces beyond our control. These estimates are generally associated with a portion of the last month of each reporting period. For the year ended December 31, 2014, we estimate that approximately 1% of annual revenues and cost of sales were recorded using sales and purchase estimates. Accordingly, a hypothetical variance of 10% from both of these estimates, either up or down in tandem, would impact annual revenues, cost of sales, operating income and net income attributable to PAA by less than 1% on an annual basis. Although the resolution of these uncertainties has not historically had a material impact on our reported results of operations or financial condition, because of the high volume, low margin nature of our business, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Variances from estimates are reflected in the period actual results become known, typically in the month following the estimate.

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

Impairment testing entails estimating future net cash flows relating to the asset, based on management s estimate of future revenues, future cash flows and market conditions including pricing, demand, competition, operating costs and other factors. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, contracts and industry expertise, involves professional judgment and is ultimately based on acquisition models and management s assessment of the value of the assets acquired and, to the extent available, third party assessments. Uncertainties associated with these estimates include changes in production decline rates, production interruptions, fluctuations in refinery capacity or product slates, economic obsolescence factors in the area and potential future sources of cash flow. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. We perform our goodwill impairment test annually (as of June 30) and when events or changes in circumstances indicate that the carrying value may not be recoverable. Through our annual testing of goodwill for potential impairment, which also includes a sensitivity analysis regarding the excess of our reporting unit s fair value over book value, we determined that the fair value of each reporting unit was substantially greater than its respective book value, and therefore goodwill was not considered impaired. See Note 7 to our Consolidated Financial Statements for a further discussion of goodwill.

Fair Value of Derivatives. Our derivatives that are not elected for the normal purchases and normal sales scope exception are reported at fair value as either assets or liabilities with changes in fair value recognized in either earnings or accumulated other comprehensive income / loss (AOCI). The fair value of a derivative at a particular period end does not reflect the end results of a particular transaction, and will most likely not reflect the 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. The valuations of our derivatives that are exchange traded are based on market prices on the applicable exchange on the last day of the period. 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. See Note 12 to our Consolidated Financial Statements for a discussion regarding our derivatives and risk management activities.

Accruals and Contingent Liabilities. We record accruals or liabilities including, but not limited to, environmental remediation and governmental penalties, asset retirement obligations, equity-indexed compensation plan accruals (as further discussed below), bonus accruals and potential legal claims. Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Our estimates are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our environmental remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment, and the possibility of existing legal claims giving rise to additional claims. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. A hypothetical 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 $15 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-Indexed Compensation Plan Accruals. We accrue compensation expense (referred to herein as equity-indexed compensation expense) for outstanding equity-indexed compensation awards. Under GAAP, we are required to estimate the fair value of our outstanding equity-indexed compensation awards and recognize that fair value as compensation expense over the service period. For equity-indexed compensation awards that contain a performance condition, the fair value of the award is recognized as compensation expense only if the attainment of the performance condition is considered probable. Uncertainties involved in this estimate include the actual unit price at time of vesting, whether or not a performance condition will be attained and the continued employment of personnel with outstanding equity-indexed compensation awards. We cannot provide assurance that the actual fair value of our equity-indexed compensation awards will not vary significantly from estimated amounts.

We recognized equity-indexed compensation expense of $98 million, $116 million and $101 million in 2014, 2013 and 2012, respectively, related to awards granted under our various equity-indexed compensation plans. A hypothetical variance of 5% in our aggregate estimate for the equity-indexed compensation expense would have an impact on net income attributable to PAA of less than 1%. See Note 16 to our Consolidated Financial Statements for a discussion regarding our equity-indexed compensation plans.

Property and Equipment and Depreciation Expense. We compute depreciation using the straight-line method based on estimated useful lives. These estimates are based on various factors including condition, manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives and salvage values that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization.

We periodically evaluate property and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. Any evaluation is highly dependent on the underlying assumptions of related cash flows. We consider the fair value estimate used to calculate impairment of property and equipment a critical accounting estimate. In determining the existence of an impairment of carrying value, we make a number of subjective assumptions as to:

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

Table of Contents

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

During 2014, 2013 and 2012, we recognized losses on impairments of long-lived assets of $10 million, $20 million and $168 million, respectively. The impairments recognized in 2014 and 2013 primarily related to assets that were taken out of service. These assets did not support spending the capital necessary to continue service and, in some instances, we utilized other assets to handle these activities. The impairments recognized in 2012 primarily related to our Pier 400 terminal project and the anticipated sale of certain refined products pipeline systems and related assets. See Note 6 to our Consolidated Financial Statements for further discussion regarding impairments.

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 (less than $5 million in the aggregate over the years ended December 31, 2014, 2013 and 2012) 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.

Inventory Valuations. Inventory, including long-term inventory, primarily consists of crude oil, NGL and natural gas and 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 use estimates and judgment when making any adjustments necessary to reduce the carrying value to net realizable value. Among the uncertainties that impact our estimates are the applicable quality and location differentials to include in our net realizable value analysis. Additionally, we also estimate the upcoming liquidation timing of the inventory. Changes in assumptions made as to the timing of a sale can materially impact net realizable value. During the years ended December 31, 2014, 2013 and 2012, we recorded charges of $289 million, $7 million and $128 million, respectively, related to the valuation adjustment of our crude oil, NGL and natural gas inventory due to declines in prices. See Note 5 to our Consolidated Financial Statements for further discussion regarding inventory.

Recent Accounting Pronouncements

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

Results of Operations

Analysis of Operating Segments

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates such segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 19 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 PAA.

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 our 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. 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 expenses 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

The following table sets forth an overview of our consolidated financial results calculated in accordance with GAAP (in millions, except for per unit amounts):

	Year Ended December 31,			Favorable/(Unfavorable) Variance			
				2014-2013		2013-2012	
	2014	2013	2012	$	%	$	%
Transportation segment profit	$ 925	$ 729	$ 710	$ 196	27%	$ 19	3%
Facilities segment profit	584	616	482	(32)	(5)%	134	28%
Supply and Logistics segment profit	782	822	753	(40)	(5)%	69	9%
Total segment profit	2,291	2,167	1,945	124	6%	222	11%
Depreciation and amortization	(392)	(375)	(482)	(17)	(5)%	107	22%
Interest expense, net	(340)	(303)	(288)	(37)	(12)%	(15)	(5)%
Other income/(expense), net	(2)	1	6	(3)	(300)%	(5)	(83)%
Income tax expense	(171)	(99)	(54)	(72)	(73)%	(45)	(83)%
Net income	1,386	1,391	1,127	(5)	%	264	23%
Net income attributable to noncontrolling interests	(2)	(30)	(33)	28	93%	3	9%
Net income attributable to PAA	$ 1,384	$ 1,361	$ 1,094	$ 23	2%	$ 267	24%
Net income attributable to PAA:							
Basic net income per limited partner unit	$ 2.39	$ 2.82	$ 2.41	$ (0.43)	(15)%	$ 0.41	17%
Diluted net income per limited partner unit	$ 2.38	$ 2.80	$ 2.40	$ (0.42)	(15)%	$ 0.40	17%
Basic weighted average limited partner units outstanding	367	341	325	26	8%	16	5%
Diluted weighted average limited partner units outstanding	369	343	328	26	8%	15	5%

Non-GAAP Financial Measures

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

Management believes that the presentation of such additional financial measures provides useful information to investors regarding our performance and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) the mark-to-market of derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), (iii) inventory valuation adjustments, (iv) items that are not indicative of our core operating results and business outlook and/or (v) other items that we believe should be excluded in understanding our core operating performance. We have defined all such items hereinafter as Selected Items Impacting Comparability. These additional financial measures are reconciled to the most directly comparable measures as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our Consolidated Financial Statements and footnotes.

Table of Contents

The following table sets forth non-GAAP financial measures that are reconciled to the most directly comparable GAAP measures (in millions):

[redacted]							
Net income	$ 1,386	$ 1,391	$ 1,127	$ (5)	%	$ 264	23%
Add:							
Interest expense, net	340	303	288	37	12%	15	5%
Income tax expense	171	99	54	72	73%	45	83%
Depreciation and amortization	392	375	482	17	5%	(107)	(22)%
EBITDA	$ 2,289	$ 2,168	$ 1,951	$ 121	6%	$ 217	11%
Selected Items Impacting Comparability of EBITDA							
Gains/(losses) from derivative activities net of inventory valuation adjustments (1)	$ 243	$ (59)	$ (74)	$ 302	512%	$ 15	20%
Long-term inventory valuation adjustments (2)	(85)			(85)	N/A		N/A
Equity-indexed compensation expense (3)	(56)	(63)	(59)	7	11%	(4)	(7)%
Net loss on foreign currency revaluation (4)	(13)	(1)	(7)	(12)	(1,200)%	6	86%
Significant acquisition-related expenses			(14)		N/A	14	100%
Other (5)		(1)	(2)	1	100%	1	50%
Selected Items Impacting Comparability of EBITDA	$ 89	$ (124)	$ (156)	$ 213	172%	$ 32	21%
EBITDA	$ 2,289	$ 2,168	$ 1,951	$ 121	6%	$ 217	11%
Selected Items Impacting Comparability of EBITDA	(89)	124	156	(213)	(172)%	(32)	(21)%
Adjusted EBITDA	$ 2,200	$ 2,292	$ 2,107	$ (92)	(4)%	$ 185	9%
Adjusted EBITDA	$ 2,200	$ 2,292	$ 2,107	$ (92)	(4)%	$ 185	9%
Interest expense, net	(340)	(303)	(288)	(37)	(12)%	(15)	(5)%
Maintenance capital (6)	(224)	(176)	(170)	(48)	(27)%	(6)	(4)%
Current income tax expense	(71)	(100)	(53)	29	29%	(47)	(89)%
Equity earnings in unconsolidated entities, net of distributions	(3)	(10)	2	7	70%	(12)	(600)%
Distributions to noncontrolling interests (7)	(3)	(38)	(48)	35	92%	10	21%
Implied DCF	$ 1,559	$ 1,665	$ 1,550	$ (106)	(6)%	$ 115	7%
Less: Distributions paid (7)	(1,469)	(1,215)	(1,017)				
DCF Excess/(Shortage) (8)	$ 90	$ 450	$ 533				

(1) We use derivative instruments for risk management purposes and our related processes include specific identification of hedging instruments to an underlying hedged transaction. Although we identify an underlying transaction for each derivative instrument we enter into, there may not be an accounting hedge relationship between the instrument and the underlying transaction. In the course of evaluating our results of operations, we identify the earnings that were recognized during the period related to derivative instruments for which the identified underlying transaction does not occur in the current period and exclude the related gains and losses in determining Adjusted EBITDA. We also exclude the impact of corresponding inventory valuation adjustments, as applicable. See Note 12 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities.

(2) We carry approximately 4 million barrels of crude oil and NGL inventory that is comprised of minimum working inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. Therefore, we classify this inventory as long-term on our balance sheet and do not hedge the inventory with derivative instruments (similar to Linefill in our own assets). We treat the impact of changes in the average cost of the long-term inventory (that result from fluctuations in market prices) as a Selected Item Impacting Comparability of EBITDA. During the fourth quarter of 2014, crude oil and NGL prices decreased significantly resulting in an inventory valuation adjustment. See Note 5 to our Consolidated Financial Statements for additional inventory disclosures.

Table of Contents

(3) Our total equity-indexed compensation expense includes expense associated with awards that will or may be settled in units and awards that will or may be settled in cash. The awards that will or may be settled in units are included in our diluted earnings per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a selected item impacting comparability as the dilutive impact of the outstanding awards is included in our diluted earnings per unit calculation and the majority of the awards are expected to be settled in units. The portion of compensation expense associated with awards that are certain to be settled in cash is not considered a selected item impacting comparability. See Note 16 to our Consolidated Financial Statements for a comprehensive discussion regarding our equity-indexed compensation plans.

(4) During 2014, 2013 and 2012, there were fluctuations in the value of the Canadian dollar (CAD) to the U.S. dollar (USD), resulting in gains and losses that were not related to our core operating results for the period and were thus classified as selected items impacting comparability. See Note 12 to our Consolidated Financial Statements for further discussion regarding our currency exchange rate risk hedging activities.

(5) Includes other immaterial selected items impacting comparability.

(6) Maintenance capital expenditures are defined as capital expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets.

(7) Includes distributions that pertain to the current period s net income and are paid in the subsequent period.

(8) Excess DCF is retained to establish reserves for future distributions, capital expenditures and other partnership purposes.

Transportation Segment

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

The following tables set forth our operating results from our Transportation segment for the periods indicated:

				Favorable/(Unfavorable) Variance			
Operating Results (1)	**Year Ended December 31,**			**2014-2013**		**2013-2012**	
(in millions, except per barrel data)	**2014**	**2013**	**2012**	**$**	**%**	**$**	**%**

Revenues						
Tariff activities	$ 1,447	$ 1,293	$ 1,232	$ 154	12%	$ 61	5%
Trucking	208	205	184	3	1%	21	11%
Total transportation revenues	1,655	1,498	1,416	157	10%	82	6%
Costs and Expenses							
Trucking costs	(151)	(147)	(134)	(4)	(3)%	(13)	(10)%
Field operating costs (2)	(560)	(528)	(468)	(32)	(6)%	(60)	(13)%
Equity-indexed compensation expense - operations	(15)	(18)	(16)	3	17%	(2)	(13)%
Segment general and administrative expenses (2) (3)	(83)	(101)	(96)	18	18%	(5)	(5)%
Equity-indexed compensation expense - general and administrative	(29)	(39)	(30)	10	26%	(9)	(30)%
Equity earnings in unconsolidated entities	108	64	38	44	69%	26	68%
Segment profit	$ 925	$ 729	$ 710	$ 196	27%	$ 19	3%
Maintenance capital	$ 165	$ 123	$ 108	$ (42)	(34)%	$ (15)	(14)%
Segment profit per barrel	$ 0.62	$ 0.54	$ 0.56	$ 0.08	15%	$ (0.02)	(4)%

Table of Contents

Average Daily Volumes (in thousands of barrels per day) (4)	Year Ended December 31, 2014	2013	2012	Favorable/(Unfavorable) Variance 2014-2013 Volumes	%	2013-2012 Volumes	%
Tariff activities							
Crude Oil Pipelines							
All American	37	40	33	(3)	(8)%	7	21%
Bakken Area Systems	149	131	130	18	14%	1	1%
Basin / Mesa / Sunrise	733	718	696	15	2%	22	3%
BridgeTex	14			14	N/A		N/A
Capline	152	151	146	1	1%	5	3%
Eagle Ford Area Systems	227	102	23	125	123%	79	343%
Line 63 / Line 2000	122	113	128	9	8%	(15)	(12)%
Manito	47	46	57	1	2%	(11)	(19)%
Mid-Continent Area Systems	348	281	271	67	24%	10	4%
Permian Basin Area Systems	765	581	461	184	32%	120	26%
Rainbow	112	124	145	(12)	(10)%	(21)	(14)%
Rangeland	65	60	62	5	8%	(2)	(3)%
Salt Lake City Area Systems	136	131	149	5	4%	(18)	(12)%
South Saskatchewan	62	51	60	11	22%	(9)	(15)%
White Cliffs	30	23	18	7	30%	5	28%
Other	767	725	703	42	6%	22	3%
NGL Pipelines							
Co-Ed	58	56	44	2	4%	12	27%
Other	128	194	131	(66)	(34)%	63	48%
Refined Products Pipelines		68	116	(68)	(100)%	(48)	(41)%
Tariff activities total	3,952	3,595	3,373	357	10%	222	7%
Trucking	127	117	106	10	9%	11	10%
Transportation segment total	4,079	3,712	3,479	367	10%	233	7%

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

(2) Field operating costs and Segment general and administrative expenses exclude equity-indexed compensation expense, which is presented separately in the table above.

(3) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

(4) Volumes associated with assets employed through acquisitions and capital expansion projects represent total volumes

(attributable to our interest) for the number of days we employed 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. Revenue from our pipeline capacity agreements generally reflects a negotiated amount.

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

Table of Contents

Net Operating Revenues and Volumes. As noted in the table above, our total Transportation segment revenues, net of trucking costs, and volumes increased year-over-year for each comparative period presented. Our Transportation segment results were impacted by the following for the years ended December 31, 2014, 2013 and 2012:

- North American Crude Oil Production During the years ended December 31, 2014 and 2013, the increase in North American crude oil production had a favorable impact on our results over the comparative periods presented. We experienced increased volumes and revenues on our existing pipeline systems, as well as incremental volumes and revenues from the expansion of certain of our pipelines systems, the construction of new pipelines and increased interconnectivity in the Permian Basin as a result of increased opportunities for midstream infrastructure development in production growth areas. For each of the comparative year-over-year periods presented, we experienced increased volumes, most notably on our Permian Basin Area Systems, Eagle Ford Area Systems (including the Eagle Ford pipeline) and certain pipelines included in our Mid-Continent Area Systems, as well as incremental revenue from increased pumpover movements at our Basin pipeline terminal. We estimate that the impact of increased production and related midstream infrastructure development increased our revenues by $95 million for the year ended December 31, 2014 over the year ended December 31, 2013 and $40 million for the year ended December 31, 2013 period over the year ended December 31, 2012.

- Loss Allowance Revenue As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor that is intended to offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative-related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. The loss allowance revenue increased by $46 million for 2014 over 2013 and was primarily driven by higher volumes. The loss allowance revenue decreased by $23 million for 2013 compared to 2012 primarily due to a lower average realized price per barrel.

- Rate Changes Revenues on our pipelines are impacted by various rate changes that occur during the period. These primarily include the indexing of rates on our FERC regulated pipelines, rate increases or decreases on our intrastate and Canadian pipelines or other negotiated rate changes. We estimate that the net impact of rate changes on our pipelines increased revenues by $40 million and $50 million during the year ended December 31, 2014 compared to 2013 and the year ended December 31, 2013 compared to 2012, respectively.

- Sale of Refined Products Pipelines We sold certain refined products pipeline systems and related assets in July 2013 and November 2013. For the year ended December 31, 2013 compared to the year ended December 31, 2012, revenues and volumes on our refined products pipelines were lower by $15 million and 48,000 barrels per day, respectively, primarily due to the sale of such pipelines and related assets. As we did not own these assets during 2014, our revenues were lower by $28 million and volumes were lower by 68,000 barrels per day as compared to the year ended December 31, 2013.

- Foreign Exchange Impact Revenues and expenses from our Canadian based subsidiaries, which use the Canadian dollar as their functional currency, are translated at the prevailing average exchange rates for each month. The average CAD to USD exchange rates for 2014, 2013 and 2012 were $1.10 CAD: $1.00 USD, $1.03 CAD: $1.00 USD, and $1.00 CAD: $1.00 USD, respectively. Therefore, we estimate that revenues from our Canadian pipeline systems and trucking operations were unfavorably impacted by $28 million for the year ended December 31, 2014 compared to the year ended December 31, 2013 and by $13 million for the year ended December 31, 2013 compared to the year ended December 31, 2012 due to the depreciation of the Canadian dollar relative to the U.S. dollar.

- BP NGL Acquisition Assets We acquired pipelines through the BP NGL Acquisition completed on April 1, 2012. These assets contributed $27 million of additional tariff revenues for the year ended December 31, 2013 over the year ended December 31, 2012, which was primarily related to the benefit from a full period of ownership of these assets (as we only owned the assets for nine months of 2012). This increase excludes the unfavorable impacts on our Co-Ed pipeline related to (i) rate changes and (ii) weather-related downtime, as discussed below.

- Weather-Related Downtime During the second and third quarters of 2013, our Rangeland, South Saskatchewan and Co-Ed pipelines in Canada were shut down due to high river flow rates and flooding in the surrounding area. We estimate that the downtime on these pipelines negatively impacted revenues and volumes by $15 million to $20 million and 15,000 to 20,000 barrels per day, respectively, for the year ended December 31, 2013. Similar weather-related downtime did not occur during the years ended December 31, 2014 or 2012 and, therefore, we experienced more favorable results in those periods as compared to the year ended December 31, 2013.

- Rail Impact Volumes and revenues, primarily on our Manito and Rainbow pipelines and certain pipelines included in our Bakken Area Systems, were unfavorably impacted by producer decisions to deliver more crude oil to rail loading facilities in the area during the year ended December 31, 2013 compared to the year ended December 31, 2012. We estimate that volumes decreased by approximately 25,000 to 30,000 barrels per day and the impact to revenues was a decrease of $20 million over the comparative periods. During the year ended December 31, 2014, we did not experience the same decrease in volumes on these pipelines as compared to the prior period, and we also experienced favorable impacts on our South Saskatchewan pipeline related to producer decisions to deliver more crude oil via pipeline as opposed to using competing alternatives such as rail.

Additional noteworthy volume and revenue variances for the year ended December 31, 2014 compared to 2013 include (i) additional revenues of $12 million resulting from a reclassification of certain of our Canadian storage facilities from our Facilities segment to our Transportation segment during the second quarter of 2014 (ii) incremental volumes and revenues from our Pascagoula, Wascana and Bakken North pipelines, which were placed into service during the second quarter of 2014, (iii) decreased volumes and revenues on certain of our NGL pipelines due to (a) the discontinuation in the fourth quarter of 2013 of an agreement to transport volumes on a pipeline and (b) the impact of netting joint venture related volumes to our share on a pipeline during 2014, which did not affect revenues and (iv) decreased volumes on our Rainbow pipeline due to (a) lower producer volumes and (b) operational issues during September 2014; however, the unfavorable revenue impact of these decreases in volumes on Rainbow pipeline was offset by favorable revenue variances from an increase in tariff rates and the reclassification of a storage facility from our Facilities segment, the impacts of both of which are discussed above.

Additional noteworthy volume and revenue variances for the year ended December 31, 2013 compared to 2012 include (i) increased volumes and revenues on our All American pipeline due to higher production levels in 2013 coupled with lower maintenance activities at the production facilities in 2013 compared to 2012, (ii) decreases on the Salt Lake City Area Systems and our Line 63 and Line 2000 pipelines due to refinery maintenance issues and lower refinery demand for pipeline barrels; however, revenues on Line 63 pipeline were consistent with 2012 results due to movements on higher tariff segments and (iii) increased trucking activity due to increased demand for production transported to rail terminals and hauls from pipeline disruptions.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) increased during the year ended December 31, 2014 compared to the year ended December 31, 2013 primarily due to (i) a change in classification of $14 million of certain costs from General and administrative expenses, (ii) increased asset integrity spending, (iii) higher property tax expense due to capital expansion and (iv) higher utility costs associated with increased throughput volumes. The increase in operating costs for the comparative year ended periods was partially offset by a reduction in environmental remediation costs and an $11 million favorable impact of foreign exchange.

Field operating costs (excluding equity-indexed compensation expense) increased during the year ended December 31, 2013 compared to the year ended December 31, 2012 primarily due to (i) higher environmental response, remediation and related repair expenses associated with pipeline releases of $21 million, (ii) higher integrity management expenses associated with smart pigging and other integrity work, (iii) higher payroll costs, primarily due to the BP NGL Acquisition and increased headcount and (iv) $4 million of cost incurred associated with the testing of certain lines that we considered bringing back into service. Excluding the impacts of the environmental response and remediation expenses, field operating costs in general remained relatively consistent on a per barrel basis during the comparable annual periods.

General and Administrative Expenses. General and administrative expenses (excluding equity-indexed compensation expenses) decreased during the year ended December 31, 2014 over the year ended December 31, 2013 due to a change in classification of $14 million of certain costs to Field operating costs and a $5 million favorable impact of foreign exchange.

General and administrative expenses (excluding equity-indexed compensation expenses) increased during the year ended December 31, 2013 over the year ended December 31, 2012 due to the continued overall growth of the segment and legal fees incurred in connection with the sale of certain of our refined products pipelines in 2013.

Equity-Indexed Compensation Expenses. A majority of our equity-indexed compensation awards (including the AAP Management Units) contain performance conditions contingent upon achieving certain distribution levels. For awards with performance conditions (such as distribution targets), expense is accrued over the service period only if the performance condition is considered probable of occurring. When awards with performance conditions that were previously considered improbable become probable, we incur additional expense in the period that our probability assessment changes. This is necessary to bring the accrued liability associated with these awards up to the level it would have been if we had been accruing for these awards since the grant date. At December 31, 2014 and 2013, we determined that PAA distribution levels of $2.90 and $2.75 per unit, respectively, were probable of occurring. Furthermore, a change in unit price impacts the fair value of our liability-classified awards. See Note 16 to our Consolidated Financial Statements for additional information regarding our equity-indexed compensation plans.

Table of Contents

On a consolidated basis, equity-indexed compensation expense decreased by approximately $18 million for the year ended December 31, 2014 over the year ended December 31, 2013 primarily due to the impact of the decrease in unit price during the year ended December 31, 2014 compared to the impact of the increase in unit price during the year ended December 31, 2013. Equity-indexed compensation expense increased by approximately $15 million for the year ended December 31, 2013 compared to the year ended December 31, 2012, primarily due to the following: (i) a more significant impact of the increase in unit price during the year ended December 31, 2013 compared to the impact of the increase during the year ended December 31, 2012, (ii) a greater number of units deemed probable of vesting for the year ended December 31, 2013 compared to the year ended December 31, 2012 and (iii) a higher average fair value per unit for those units deemed probable of vesting for the year ended December 31, 2013 compared to the year ended December 31, 2012.

Equity Earnings in Unconsolidated Entities. The favorable variance in equity earnings in unconsolidated entities for the year ended December 31, 2014 compared to the year ended December 31, 2013 was primarily driven by (i) increased throughput on the Eagle Ford pipeline as a result of increased crude oil production, as discussed above, (ii) increased throughput on the White Cliffs pipeline due to an expansion of the pipeline that was placed into service in July 2014, and (iii) earnings from our interest in BridgeTex, which we acquired in November 2014.

The favorable variance for the year ended December 31, 2013 compared to the year ended December 31, 2012 was largely due to (i) increased throughput on the Eagle Ford and White Cliffs pipelines as a result of increased production, as discussed above and (ii) increased capacity related to vessel additions and increased rates on services provided by Settoon Towing.

Maintenance Capital. Maintenance capital consists of capital expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets. The increase in maintenance capital in 2014 compared to 2013 is primarily due to pipeline replacement projects and increased investments in pipeline integrity. The increase in maintenance capital in 2013 compared to 2012 is primarily due to increased investments on pipeline integrity projects.

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, NGL and natural gas, as well as NGL fractionation and isomerization services and natural gas and condensate processing services. The Facilities segment generates revenue through a combination of month-to-month and multi-year agreements and processing arrangements.

The following tables set forth our operating results from our Facilities segment for the periods indicated:

					Favorable/(Unfavorable) Variance			
Operating Results (1)	**Year Ended December 31,**				**2014-2013**		**2013-2012**	
(in millions, except per barrel data)	**2014**	**2013**	**2012**		**$**	**%**	**$**	**%**
Revenues	$ 1,127	$ 1,075	$ 868		$ 52	5%	$ 207	24%
Natural gas sales (2)		302	230		(302)	(100)%	72	31%
Storage related costs (natural gas related)	(55)	(16)	(22)		(39)	(244)%	6	27%

Natural gas sales costs (2)		(296)	(216)	296	100%	(80)	(37)%
Field operating costs (3)	(404)	(362)	(289)	(42)	(12)%	(73)	(25)%
Equity-indexed compensation expense - operations	(4)	(2)	(2)	(2)	(100)%		%
Segment general and administrative expenses (3) (4)	(60)	(63)	(64)	3	5%	1	2%
Equity-indexed compensation expense - general and administrative	(20)	(22)	(23)	2	9%	1	4%
Segment profit	$ 584	$ 616	$ 482	$ (32)	(5)%	$ 134	28%
Maintenance capital	$ 52	$ 38	$ 49	$ (14)	(37)%	$ 11	22%
Segment profit per barrel	$ 0.40	$ 0.43	$ 0.38	$ (0.03)	(7)%	$ 0.05	13%

Table of Contents

	Year Ended December 31,			Favorable/(Unfavorable) Variance			
				2014-2013		2013-2012	
Volumes (5)	**2014**	**2013**	**2012**	**Volumes**	**%**	**Volumes**	**%**
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	95	94	90	1	1%	4	4%
Rail load / unload volumes (average volumes in thousands of barrels per day)	231	221		10	5%	221	N/A
Natural gas storage (average monthly working capacity in billions of cubic feet)	97	96	84	1	1%	12	14%
NGL fractionation (average volumes in thousands of barrels per day)	96	96	79		%	17	22%
Facilities segment total (average monthly volumes in millions of barrels) (6)	121	120	106	1	1%	14	13%

---

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

(2) Effective January 1, 2014, our natural gas sales and costs, primarily attributable to the activities performed by our natural gas storage commercial optimization group, are reported in our Supply and Logistics segment.

(3) Field operating costs and Segment general and administrative expenses exclude equity-indexed compensation expense, which is presented separately in the table above.

(4) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

(5) Volumes associated with assets employed through acquisitions and capital expansion projects represent total volumes for the number of months we employed the assets divided by the number of months in the period.

(6) Facilities segment total is calculated as the sum of: (i) crude oil, refined products and NGL terminalling and storage capacity; (ii) rail load and unload volumes multiplied by the number of days in the year and divided by the number of months in the year; (iii) natural gas storage working capacity divided by 6 to account for the 6:1 mcf of natural gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iv) NGL fractionation volumes multiplied by the number of days in the year and divided by the number of months in the year.

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

Net Operating Revenues and Volumes. As noted in the table above, our Facilities segment revenues, less storage related costs, and volumes increased year-over-year for each comparative period presented, albeit with a less significant increase for the year ended December 31, 2014 over the year ended December 31, 2013. Variances in net revenues and average monthly volumes between the comparative periods are discussed below:

- NGL Fractionation, NGL Storage and Natural Gas Processing Activities Revenues increased by $31 million for the year ended December 31, 2014 over the year ended December 31, 2013 largely driven by higher facility fee revenues due to rate increases at certain of our storage and fractionation facilities, partially offset by lower physical processing gains. This increase in NGL revenues includes estimated unfavorable foreign currency impacts of $18 million due to the depreciation of the Canadian dollar relative to the U.S. dollar. The average CAD to USD exchange rate for the year ended December 31, 2014 was $1.10 CAD: $1.00 USD and $1.03 CAD: $1.00 USD for the year ended December 31, 2013.

Our NGL fractionation plants, storage and processing facilities and related assets were primarily acquired through the BP NGL Acquisition completed in April 2012. These assets contributed $87 million of aggregate revenues for the year ended December 31, 2013 over the year ended December 31, 2012, primarily due to the benefit from a full period of ownership of these assets in 2013 (as we only owned the assets for nine months of 2012), as well as from physical processing gains recognized primarily at certain of our NGL fractionation facilities.

- Natural Gas Storage Operations Net revenues decreased by $43 million for the year ended December 31, 2014 compared to the year ended December 31, 2013 primarily due to (i) less favorable storage rates on contracts that renewed or replaced expiring contracts, (ii) costs incurred to manage deliverability requirements in conjunction with the extended period of severe cold weather experienced during the first quarter of 2014 and (iii) lower hub services revenues due to limited market opportunities.

Natural gas storage net revenues remained relatively consistent for the year ended December 31, 2013 compared to the year ended December 31, 2012 as less favorable storage rates largely offset incremental revenues from the expansions of our Pine Prairie and Southern Pines facilities.

- Rail Terminals For the year ended December 31, 2014, revenues increased by $3 million over the year ended December 31, 2013 due to new rail terminals that came on line in the fourth quarter of 2013 and in 2014, substantially offset by the unfavorable impact of rail delays and lower volumes at certain of our existing rail terminals during 2014 and weather-related issues at certain of our terminals during the first quarter of 2014.

Rail activities contributed $103 million to the increase in total revenues for the year ended December 31, 2013 over the year ended December 31, 2012 due to revenues from new terminals acquired through the USD Rail Terminal Acquisition completed in December 2012 and rail-related expansion projects placed into service during the latter portion of 2012 and 2013.

- Crude Oil Storage Activities For the year ended December 31, 2014, revenues increased by $8 million over the year ended December 31, 2013 primarily due to increased throughput at our Cushing, Yorktown and Mobile/Ten Mile terminals and a 1.2 million barrel capacity expansion at our St. James terminal, partially offset by lower revenues from certain storage facilities in California and the East Coast due to underutilization resulting from decreased demand, as well decreased revenues of $12 million due to the reclassification of certain of our Canadian storage facilities to our Transportation segment during the second quarter of 2014.

Revenues from our crude oil storage activities increased by $6 million for the year ended December 31, 2013 over the year ended December 31, 2012. Incremental revenues from expansion projects that were completed in phases at our Cushing, Patoka, St. James and Yorktown terminals were partially offset by decreased demand for storage at certain facilities in California and the East Coast.

- Condensate Processing Activities Revenues increased by $8 million for the year ended December 31, 2014 compared to 2013 and by $5 million for the year ended December 31, 2013 compared to 2012 due to the benefit from the start-up and subsequent expansion of our Gardendale condensate processing facility.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expenses) increased during the year ended December 31, 2014 compared to the year ended December 31, 2013 due to (i) an increase in costs for rail activities, primarily due to new rail terminals that came online in the fourth quarter of 2013 and in 2014 as discussed above, (ii) a change in classification of $8 million of certain costs from General and administrative expenses, (iii) an increase in brine disposal costs associated with our NGL storage caverns, (iv) higher gas and power costs and (v) increased costs associated with the cancellation of certain capital projects. The effect of these increases was reduced by a $9 million favorable impact of foreign exchange.

Field operating costs (excluding equity-indexed compensation expenses) increased during the year ended December 31, 2013 compared to the year ended December 31, 2012 due to our growth through acquisitions, primarily the BP NGL and USD Rail Terminal Acquisitions. A portion of the increase was also related to additional costs for integrity and other maintenance, particularly on the assets that were part of the BP NGL Acquisition.

General and Administrative Expenses. General and administrative expenses (excluding equity-indexed compensation expenses) decreased during the year ended December 31, 2014 compared to the year ended December 31, 2013. These results reflect the net impact of a decrease due to a change in classification of $8 million of certain costs to Field operating costs during the 2014 period, partially offset by increased expenses resulting from overall growth in the segment.

Maintenance Capital. The increase in maintenance capital in 2014 from 2013 is primarily due to the timing of maintenance projects for tanks and other facility assets. The decrease in maintenance capital in 2013 from 2012 is primarily due to two major equipment replacement projects that occurred in 2012.

Table of Contents

Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, as well as sales of NGL volumes purchased from suppliers and natural gas sales attributable to the activities performed by our natural gas storage commercial optimization group. Generally, we expect our segment profit to increase or decrease directionally with (i) increases or decreases in our Supply and Logistics segment volumes (which consist of lease gathering crude oil purchase volumes, NGL sales volumes and waterborne cargos), (ii) demand for lease gathering services we provide producers and (iii) the overall volatility and strength or weakness of market conditions and the allocation of our assets among our various risk management strategies. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. We do not anticipate that future changes in revenues resulting from variances in commodity prices will be a primary driver of segment profit.

The following tables set forth our operating results from our Supply and Logistics segment for the periods indicated:

Operating Results (1) (2) (in millions, except per barrel data)	Year Ended December 31, 2014	 2013	 2012	Favorable/(Unfavorable) Variance 2014-2013 $	 %	 2013-2012 $	 %
Revenues	$ 42,150	$ 40,696	$ 36,440	$ 1,454	4%	$ 4,256	12%
Purchases and related costs (3)	(40,752)	(39,315)	(35,139)	(1,437)	(4)%	(4,176)	(12)%
Field operating costs (4)	(481)	(422)	(417)	(59)	(14)%	(5)	(1)%
Equity-indexed compensation expense - operations	(2)	(3)	(2)	1	33%	(1)	(50)%
Segment general and administrative expenses (4) (5)	(105)	(102)	(101)	(3)	(3)%	(1)	(1)%
Equity-indexed compensation expense - general and administrative	(28)	(32)	(28)	4	13%	(4)	(14)%
Segment profit	$ 782	$ 822	$ 753	$ (40)	(5)%	$ 69	9%
Maintenance capital	$ 7	$ 15	$ 13	$ 8	53%	$ (2)	(15)%
Segment profit per barrel	$ 1.85	$ 2.09	$ 2.05	$ (0.24)	(11)%	$ 0.04	2%

Average Daily Volumes (in thousands of barrels per day)	Year Ended December 31, 2014	 2013	 2012	Favorable (Unfavorable) Variance 2014-2013 Volume	 %	 2013-2012 Volume	 %
Crude oil lease gathering purchases	949	859	818	90	10%	41	5%
NGL sales	208	215	182	(7)	(3)%	33	18%
Waterborne cargos		4	3	(4)	(100)%	1	33%
Supply and Logistics segment total	1,157	1,078	1,003	79	7%	75	7%

(1) Revenues and costs include intersegment amounts.

(2) Prior to January 1, 2014, natural gas sales and costs attributable to the activities performed by our natural gas storage commercial optimization group were reported in our Facilities segment.

(3) Purchases and related costs include interest expense (related to hedged inventory purchases) of $12 million, $30 million and $12 million for the years ended December 31, 2014, 2013, and 2012, respectively.

(4) Field operating costs and Segment general and administrative expenses exclude equity-indexed compensation expense, which is presented separately in the table above.

(5) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

Table of Contents

The following table presents the range of the NYMEX West Texas Intermediate benchmark price of crude oil during the periods indicated:

	NYMEX WTI Crude Oil Price			
During the Year Ended December 31,		**Low**		**High**
2014	$	53	$	107
2013	$	87	$	111
2012	$	77	$	111

Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. The absolute amount of our revenues and purchases increased for the comparative periods presented, primarily resulting from higher crude oil volumes in the 2014 period and higher crude oil and NGL volumes in the 2013 period. The impact of the increase in volumes in 2014 was partially offset by lower crude oil prices relative to 2013, particularly in the fourth quarter.

Generally, we expect a base level of earnings from our Supply and Logistics segment from the assets employed by this segment. This base level may be optimized and enhanced when there is a high level of market volatility, favorable basis differentials and/or a steep contango or backwardated market structure. Also, our NGL marketing operations are sensitive to weather-related demand, particularly during the approximate five-month peak heating season of November through March, and temperature differences from period-to-period may have a significant effect on NGL demand and thus our financial performance.

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

Net Operating Revenues and Volumes. Our Supply and Logistics segment revenues, net of purchases and related costs, increased year-over-year for each comparative period presented. The following summarizes the more significant items in the comparative periods:

- NGL Marketing Operations   Net revenues from our NGL marketing operations decreased for the year ended December 31, 2014 as compared to the year ended December 31, 2013. This decrease was driven by higher NGL purchases and related costs in the 2014 periods, primarily due to (i) a higher weighted average inventory cost, (ii) increased facility fees and (iii) a $10 million long-term inventory valuation adjustment. The long-term inventory valuation adjustment related to inventory necessary to meet our minimum inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. Additionally, NGL margins were further impacted by less favorable market conditions, most notably during (i) the second quarter of 2014, as market pricing was stronger in the comparable 2013 period due to heating requirements during a winter season that extended into the second quarter and greater petrochemical demand for propane and (ii) the fourth quarter of 2014, due to less demand for crop drying as compared to the 2013 period.

Increased net revenues from our NGL marketing operations for the year ended December 31, 2013 as compared to the year ended December 31, 2012, were primarily due to more favorable market prices and higher demand related to (i) increases in export capacity in the U.S. that reduced overall product availability in the market, (ii) increased heating requirements during the extended winter season discussed above, (iii) heavy crop drying and (iv) petrochemical demand as well as more favorable supply contracts.

• Impact from Certain Derivative Activities, Net of Inventory Valuation Adjustments The mark-to-market valuation of certain of our derivative activities impacted our net revenues as shown in the table below (in millions):

	Year Ended December 31, 2014	2013	2012	Variance 2014-2013	2013-2012
Gains/(losses) from certain derivative activities, net of inventory valuation adjustments (1)	$ 261	$ (59)	$ (75)	$ 320	$ 16

(1) Includes mark-to-market and other gains and losses resulting from certain derivative instruments that are related to underlying activities in future periods or the reversal of mark-to-market gains and losses from the prior period. These amounts are reduced by the net impact of inventory valuation adjustments attributable to inventory hedged by the related derivative and gains recognized in later periods on physical sales of inventory that was previously written

Table of Contents

down. See Note 12 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities.

• North American Crude Oil Production and Related Market Economics The significant increase in crude oil and liquids-rich gas production growth in North America has created regional supply and demand imbalances due to the lack of sufficient infrastructure to support the movement of such production, which increased certain crude oil location differentials. The lack of existing pipeline takeaway capacity and associated logistical challenges created market conditions that provided opportunities to capture above-baseline margins in our supply and logistics crude oil activities over the last few years.

Net revenues from our crude oil supply and logistics activities decreased for 2014 as compared to 2013. This decrease was driven by higher purchases and related costs, primarily due to a $75 million long-term inventory valuation adjustment. As also discussed in our NGL Marketing Operations section above, the long-term inventory valuation adjustment related to inventory necessary to meet our minimum inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. This unfavorable impact to the period was partially offset by favorable impacts from the widening of certain differentials, most notably in the second and third quarters of 2014 that allowed for more opportunities to capture above-baseline margins as compared to 2013.

Net revenues from our crude oil supply and logistics activities also decreased for 2013 as compared to 2012. During the first quarter of 2013, the market conditions discussed above provided opportunities for increased margins. However, infrastructure additions in many of the impactful resource plays during the second and third quarters of 2013 began to relieve certain of the transportation constraints that had created opportunities for these favorable crude oil margins. Therefore, although we experienced higher crude oil lease gathering volumes in 2013 compared to 2012, we experienced fewer opportunities to capture favorable differentials from market dislocations.

We believe the fundamentals of our business remain strong, as crude oil lease gathering purchases volumes in 2014 increased by 10% over 2013. However, as midstream infrastructure continues to be developed, we believe a normalization of margins will continue to occur as the logistics challenges are addressed. (See Items 1 and 2 Business and Properties Description of Segments and Associated Assets Supply and Logistics Segment Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model included in Part I for further discussion regarding our business model, including diversification and utilization of our asset base among varying demand- and supply-driven markets.)

• Natural Gas Storage Commercial Optimization Our natural gas storage commercial optimization activities for the year ended December 31, 2014 were unfavorably impacted by costs incurred to manage deliverability requirements in conjunction with the extended period of severe cold weather experienced during the first quarter of 2014.

Field Operating Costs. The increase in field operating costs (excluding equity-indexed compensation expenses) for the year ended December 31, 2014 over the year ended December 31, 2013 was primarily due to an increase in trucking costs associated with higher crude oil lease gathering purchases volumes and mark-to-market losses on fuel hedges.

Maintenance Capital. The decrease in maintenance capital in 2014 compared to 2013 was primarily due to reduced spending on trucking assets.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense includes losses on impairments of long-lived assets of approximately $10 million, $20 million and $168 million, for the 2014, 2013 and 2012 periods, respectively. The impairments recognized in 2014 and 2013 primarily related to assets that were taken out of service. These assets did not support spending the capital necessary to continue service and, in some instances, we utilized other assets to handle these activities. The impairments recognized in 2012 primarily related to our Pier 400 terminal project and the anticipated sale of certain refined products pipeline systems and related assets, which occurred in 2013. See Note 6 to our Consolidated Financial Statements for further discussion of asset impairments.

Excluding the impact of asset impairments, depreciation and amortization expense increased during the 2014 period over the comparable 2013 period primarily due to various recently completed capital expansion projects, as well as an acceleration of depreciation on certain pipeline assets to reflect a change in their estimated useful lives. These increases were partially offset by a reduction in amortization expense due to declining-balance amortization used for certain of our intangible assets acquired in recent years.

Table of Contents

Excluding the impact of asset impairments, depreciation and amortization expense increased during the 2013 period over the comparable 2012 period primarily due to an increased amount of assets resulting from acquisition activities, as well as various capital expansion projects completed in recent years.

Interest Expense

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 and included in purchases and related costs.

The following table summarizes the components impacting the interest expense variance for the years ended December 31, 2014 and 2013 (in millions, except for percentages):

			Average LIBOR Rate	Weighted Average Interest Rate (1)
Interest expense for the year ended December 31, 2012	$	288	0.2%	5.2%
Impact of issuance of senior notes (2) (3)		47		
Impact of interest included in purchases and related costs (4)		(18)		
Impact of retirement of senior notes (5) (6)		(15)		
Impact of ineffective portion of terminated forward-starting swaps		(4)		
Other		5		
Interest expense for the year ended December 31, 2013	$	303	0.2%	4.6%
Impact of issuance of senior notes (3) (7)		51		
Impact of interest included in purchases and related costs (4)		18		
Impact of retirement of senior notes (6)		(13)		
Impact of capitalized interest		(10)		
Other		(9)		
Interest expense for the year ended December 31, 2014	$	340	0.1%	4.5%

(1) Excludes commitment and other fees.

(2) In March 2012, we completed the issuance of $750 million of 3.65% senior notes due 2022 and $500 million of 5.15% senior notes due 2042, and in December 2012, we completed the issuance of $400 million of 2.85% senior notes due 2023 and $350 million of 4.30% senior notes due 2043.

(3) In August 2013, we completed the issuance of $700 million of 3.85% senior notes due 2023.

(4) Interest costs attributable to borrowings for hedged inventory purchases 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 costs were $12 million, $30 million and $12 million for the years ended December 31, 2014, 2013, and 2012, respectively.

(5) In September 2012, our $500 million, 4.25% senior notes matured.

(6) In December 2013, our $250 million, 5.63% senior notes matured.

(7) In April 2014, we completed the issuance of $700 million of 4.70% senior notes due 2044, in September 2014, we completed the issuance of $750 million of 3.60% senior notes due 2024 and in December 2014, we completed the issuance of $500 million of 2.60% senior notes due 2019 and $650 million of 4.90% senior notes due 2045.

Table of Contents

Other Income/(Expense), Net

Other income/(expense), net in each of the years ended December 31, 2014, 2013 and 2012 was primarily comprised of foreign currency gains or losses related to revaluations of CAD-denominated interest receivables associated with our intercompany notes and the impact of related foreign currency hedges.

Income Tax Expense

Income tax expense increased for the year ended December 31, 2014 compared to the year ended December 31, 2013 primarily as a result of higher deferred income tax expense associated with derivative mark-to-market gains in our Canadian operations. The increased deferred income tax expense was partially offset by lower current income tax expense as a result of decreased year-over-year taxable earnings from our Canadian operations.

Income tax expense increased for year ended December 31, 2013 compared to the year ended December 31, 2012 primarily as a result of stronger performance from our existing Canadian operations and our operations related to the BP NGL Acquisition, both of which increased the proportion of earnings subject to Canadian federal and provincial taxes.

Outlook

Primarily as a result of advances in drilling and completion techniques and their application to a number of large-scale shale and resource plays occurring contemporaneously with attractive crude oil and liquids prices, U.S. crude oil and liquids production over the last several years has increased rapidly in multiple regions in the lower 48 states. This has been particularly true for light crudes and condensates. Similar resource development activities in Canada and ongoing oil sands development activities have also led to increased Canadian crude oil production. Additionally, the crude oil market has periodically experienced high levels of volatility in location and quality differentials as a result of the confluence of regional infrastructure constraints in North America, rapid and unexpected changes in crude oil qualities, international supply issues, and regional downstream operating issues. During 2013 and to a lesser degree 2014, these market conditions had a positive impact on our profitability as our business strategy and asset base positioned us to capitalize on opportunities created by the volatile environment.

However, over the last several years the combination of surging North American liquids production, relatively flat liquids production for the rest of the world and relatively modest growth in global liquids demand has led to a near to medium-term supply imbalance, which has further led to a significant and rapid reduction in petroleum prices and compression of basis differentials in a number of locations. While we believe that our business model and asset base have minimal direct exposure to petroleum prices, our performance is influenced by certain differentials and overall North American production levels, which in turn are impacted by major price movements. The meaningful decrease in crude oil prices during the second half of 2014 and early 2015 have led many producers, including producers that impact North American production levels, to significantly scale back capital programs for the next year or more. While we believe that the large North American resource base remains intact and will be developed, such production will likely take place at a slower pace and previously anticipated peak production levels will likely be reduced. This transitioning crude oil market may present challenges to our business model and asset base and may impact the rate of growth that we would have otherwise experienced over the next several years. In addition, increased competition and compressed differentials may drive lower unit margins in parts of our business, including our Supply and Logistics segment.

While we believe that these recent market developments should ultimately slow down crude oil supply growth and contribute toward bringing the markets back to equilibrium, there can be no assurance that such equilibrium will be achieved or that we will not be negatively impacted by declining crude oil supply, unfavorable volatility or challenging capital markets conditions. Additionally, construction of additional infrastructure by us and our competitors will likely continue to reduce existing infrastructure constraints, which could further reduce unit margins in our various segments, and underutilization of midstream assets resulting from continued production declines could have a similar unfavorable impact on unit margins. Finally, we cannot be certain that our expansion efforts will generate targeted returns or that any future acquisition activities will be successful. See Item 1A. Risk Factors - Risks Related to Our Business.

Table of Contents

Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) cash flow from operating activities as further discussed below in the section entitled Cash Flow from Operating Activities, (ii) borrowings under our credit facilities or commercial paper program and (iii) funds received from sales of equity and debt securities. Our primary cash requirements include, but are not limited to (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil, NGL and other products and other expenses and interest payments on outstanding debt, (ii) expansion and maintenance activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on our long-term debt and (v) distributions to our unitholders and general partner. We generally expect to fund our short-term cash requirements through cash flow generated from operating activities and/or borrowings under our commercial paper program or credit facilities. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions and refinancing our long-term debt, through a variety of sources (either separately or in combination), which may include the sources mentioned above as funding for short-term needs and/or the issuance of additional equity or debt securities. As of December 31, 2014, we had a working capital deficit of $576 million and approximately $2.6 billion of liquidity available to meet our ongoing operating, investing and financing needs as noted below (in millions):

	As of December 31, 2014
Availability under PAA senior unsecured revolving credit facility (1)	$ 1,591
Availability under PAA senior secured hedged inventory facility (1)	1,322
Amounts outstanding under PAA commercial paper program	(734)
Subtotal	2,179
Cash and cash equivalents	403
Total	$ 2,582

(1) Represents availability prior to giving effect to amounts outstanding under the PAA commercial paper program. Borrowings under the PAA commercial paper program reduce available capacity under the facility.

On January 16, 2015, we entered into a new $1.0 billion, 364-day senior unsecured credit agreement. Pursuant to the terms of the agreement, we have up to 364 days to draw on this facility and repay any loans thereunder.

We believe that we have, and will continue to have, the ability to access the commercial paper program and credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a materially adverse effect on our financial condition, results of operations or cash flows. Also, see Item 1A. Risk Factors for further discussion regarding such risks that may impact our liquidity and capital resources. Usage of the credit facilities, which provide the backstop for the commercial paper program, is subject to ongoing compliance with covenants. As of December 31, 2014, we were in compliance with all such covenants.

Cash Flow from Operating Activities

The primary drivers of cash flow from operating activities are (i) the collection of amounts related to the sale of crude oil, NGL and other products, the transportation of crude oil and other products for a fee, and storage and terminalling services provided for a fee and (ii) the payment of amounts related to the purchase of crude oil, NGL and other products and other expenses, principally field operating costs, general and administrative expenses and interest expense.

Cash flow from operating activities can be materially impacted by 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. In the month we pay for the stored crude oil, we borrow under our credit facilities or commercial paper program (or use cash on hand) to pay for the crude oil, which negatively impacts operating cash flow. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored crude oil. Similarly, the level of NGL 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 or commercial paper program 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, regardless of market structure, we may rely on our credit facilities or commercial paper program to pay for the inventory. In addition, we use derivative instruments to manage the risks associated with the purchase and sale of our commodities. Therefore, our cash flow from operating activities may be impacted by the margin deposit requirements related to our derivative activities and/or the timing of settlement of our derivative

Table of Contents

activities. For example, 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. See Note 12 to our Consolidated Financial Statements for a discussion regarding our derivatives and risk management activities.

Net cash provided by operating activities for the years ended December 31, 2014, 2013 and 2012 was approximately $2.0 billion, $1.95 billion and $1.24 billion, respectively, and primarily resulted from earnings from our operations. Additionally, as discussed further below, changes in our inventory levels during these years impacted our cash flow from operating activities.

During 2014, we decreased the volume of our crude oil inventory that we held. The decreased inventory levels were further impacted by lower prices for such inventory stored at the end of the year compared to prior year amounts. In addition, our margin balances fluctuated from a net cash outflow to a net cash inflow. A portion of the net proceeds received from the liquidation of such inventory and the positive cash flow associated with our margin balance activities were used to repay borrowings under our commercial paper program and favorably impacted cash flow from operating activities. These overall decreases were partially offset by an increase in the amount of NGL inventory stored at December 31, 2014 compared to prior year amounts, which was primarily financed through borrowings under our commercial paper program.

During 2013, we decreased the amount of our inventory, primarily due to the sale of crude oil inventory that had been stored during the contango market, as well as the sale of NGL inventory due to end users increased demand for product used for heating and crop drying during the latter half of 2013. The net proceeds received from liquidation of such inventory during the year were used to repay borrowings under our credit facilities or commercial paper program and favorably impacted cash flow from operating activities. These decreases in inventory were partially offset by an increase in natural gas inventory whereby we retained more capacity for our own use. We primarily used borrowings under credit facilities to pay for the stored natural gas, which negatively impacted our cash flow from operating activities. Also, a significant portion of our 2013 natural gas sales occurred in December 2013, with cash collections on these sales occurring in January 2014.

During 2012, we increased the amount of our crude oil inventory, which was primarily financed through borrowings under our credit facilities. This resulted in a negative impact on our cash flow from operating activities for the period. During the year, we also increased the amount of our NGL inventory; however, these volumetric increases were offset by lower prices for such inventory stored at the end of the year compared to prior year amounts.

Credit Agreements, Commercial Paper Program and Indentures

At December 31, 2014, we had three primary credit arrangements. These include a $1.6 billion senior unsecured revolving credit facility maturing in 2019 and a $1.4 billion senior secured hedged inventory facility maturing in 2017. Additionally, we have a $3.0 billion unsecured commercial paper program that is backstopped by our revolving credit facility and our hedged inventory facility. Our credit agreements (which impact our ability to access our commercial paper program because they provide the backstop that supports our short-term credit ratings) and the indentures governing our senior notes contain cross-default provisions. A default under our credit agreements 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 were in compliance with the covenants contained in our credit agreements and indentures as of December 31, 2014.

Additionally, in January 2015, we entered into a new $1.0 billion, 364-day senior unsecured credit agreement. See Note 10 to our Consolidated Financial Statements for additional discussion regarding our credit agreements, commercial paper program and senior notes.

Equity and Debt Financing Activities

Our financing activities primarily relate to funding acquisitions, expansion capital projects and refinancing of our debt maturities, as well as short-term working capital and hedged inventory borrowings related to our NGL 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 or commercial paper program, as well as payment of distributions to our unitholders and general partner.

Registration Statements. We periodically access the capital markets for both equity and debt financing. We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $2.0 billion of debt or equity securities (Traditional Shelf). All issuances of equity securities associated with our continuous offering program have been issued pursuant to the Traditional Shelf. At December 31, 2014, we had approximately $613 million of unsold securities available under the Traditional Shelf. We also have access to a universal shelf registration statement (WKSI Shelf), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. During 2014, we issued four series of senior notes under the WKSI Shelf. See Senior Notes below.

Table of Contents

Equity Offerings. The following table summarizes our issuance of common units in connection with marketed offerings or our Continuous Offering Program during the three years ended December 31, 2014 (net proceeds in millions):

Year	Type of Offering	Units Issued	Net Proceeds (1) (2)
2014 Total	Continuous Offering Program	15,375,810	$ 866(3)
2013 Total	Continuous Offering Program	8,644,807	$ 477(3)
2012	Continuous Offering Program	12,063,707	$ 524(3)
2012	Marketed Offering	11,500,000	455(4)
2012 Total		23,563,707	$ 979

(1) Amounts are net of costs associated with the offerings.

(2) Amounts include our general partner s proportionate capital contributions of $18 million, $9 million and $20 million during 2014, 2013 and 2012, respectively.

(3) We pay commissions to our sales agents in connection with common unit issuances under our Continuous Offering Program. We paid $9 million, $5 million and $6 million of such commissions during 2014, 2013 and 2012, respectively. The net proceeds from these offerings were used for general partnership purposes.

(4) Offering was an underwritten transaction that required us to pay a gross spread. The net proceeds from such offering were used to fund a portion of the BP NGL Acquisition.

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

Year	Description	Maturity	Face Value	Gross Proceeds(1)	Net Proceeds(2)
2014	2.60% Senior Notes issued at 99.813% of face value (3)	December 2019	$ 500	$ 499	$ 495
2014	4.90% Senior Notes issued at 99.876% of face value (3)	February 2045	$ 650	$ 649	$ 643
2014	3.60% Senior Notes issued at 99.842% of face value (4)	November 2024	$ 750	$ 749	$ 743
2014	4.70% Senior Notes issued at 99.734% of face value (4)	June 2044	$ 700	$ 698	$ 691
2013	3.85% Senior Notes issued at 99.792% of face value (4)	October 2023	$ 700	$ 699	$ 693
2012	2.85% Senior Notes issued at 99.752% of face value (4)	January 2023	$ 400	$ 399	$ 396
2012	4.30% Senior Notes issued at 99.925% of face value (4)	January 2043	$ 350	$ 350	$ 346

2012	3.65% Senior Notes issued at 99.823% of face value (5)	June 2022	$	750	$	749	$	742
2012	5.15% Senior Notes issued at 99.755% of face value (5)	June 2042	$	500	$	499	$	494

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

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

(3) We used the net proceeds from this offering to repay outstanding borrowings under our commercial paper program (a portion of which was used to fund the acquisition of a 50% interest in BridgeTex). See Note 8 to our Consolidated Financial Statements for further discussion.

(4) We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities or commercial paper program and for general partnership purposes.

Table of Contents

(5) We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities and for general partnership purposes. In addition, we used a portion of the proceeds to prefund the BP NGL Acquisition. See Note 3 to our Consolidated Financial Statements for a discussion of the BP NGL Acquisition.

In December 2013, our $250 million, 5.63% senior notes matured and were repaid with proceeds from our commercial paper program. In September 2012, our $500 million, 4.25% senior notes matured and were repaid with proceeds from our credit facilities.

Our $150 million, 5.25% senior notes will mature in June 2015, and our $400 million, 3.95% senior notes will mature in September 2015. We intend to use borrowings under our commercial paper program to repay these senior notes when they mature.

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

In addition to operating needs discussed above, we also use cash for our acquisition activities, capital projects and distributions paid to our unitholders, general partner and noncontrolling interests. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations and the financing activities discussed above. See Acquisitions and Capital Projects for further discussion of such capital expenditures.

Acquisitions. The price of 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. On November 14, 2014, we acquired a 50% interest in BridgeTex for $1.088 billion, including $13 million of working capital adjustments.

2015 Capital Projects. We expect the majority of funding for our 2015 capital program will be provided by borrowings under our commercial paper program as well as through our access to the capital markets for equity and debt as we deem necessary. Our capital program is highlighted by a large number of small-to-medium sized projects spread across multiple geographic regions/resource plays. We believe the diversity of our program mitigates the impact of delays, cost overruns or adverse market developments with respect to a particular project or geographic region/resource play. The majority of our 2015 expansion capital program will be invested in our fee-based Transportation and Facilities segments. We expect that our investments will have minimal contributions to our 2015 results, but will provide growth for 2016 and beyond. Our 2015 capital program includes the following projects as of February 2015 with the estimated cost for the entire year (in millions):

Projects	**2015**
Permian Basin Area Projects	$365
Fort Saskatchewan Facility Projects / NGL Line	290
Rail Terminal Projects (1)	240
Diamond Pipeline	165
Eagle Ford JV Project	85
Cactus Pipeline	85
Red River Pipeline (Cushing to Longview)	80
Cowboy Pipeline (Cheyenne to Carr)	50

Eagle Ford Area Projects	35
Line 63 Reactivation	30
Cushing Terminal Expansions	25
Other Projects	400
	$1,850
Potential Adjustments for Timing / Scope Refinement (2)	-$100 + $100
Total Projected Expansion Capital Expenditures	$1,750 - $1,950
Maintenance Capital Expenditures	$205 - $225

(1) Includes railcar purchases and projects located in or near St. James, LA and Kerrobert, Canada.

Table of Contents

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

Distributions to our unitholders and general partner. We distribute 100% of our available cash within 45 days following 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 13, 2015, we paid a quarterly distribution of $0.6750 per limited partner unit. This distribution represents a year-over-year distribution increase of approximately 9.8%. See Note 11 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 regarding distributions.

Although not required to do so, in response to past requests by our management in connection with our acquisition activities, our general partner has, from time to time, agreed to reduce the amounts due to it as incentive distributions. Such modifications were implemented with a view toward enhancing our competitiveness for such acquisitions and managing the overall cost of equity capital while achieving an appropriate balance between short-term and long-term accretion to our limited partners and the holders of our general partner interest and IDRs. Our general partner agreed to reduce the amount of its incentive distribution by $6.75 million for the distribution paid in February 2014, $5.5 million per quarter thereafter through November 2015, $5.0 million per quarter in 2016 and $3.75 million per quarter thereafter. These reductions were agreed to in connection with our BP NGL Acquisition and the PNG Merger. See Note 3 to our Consolidated Financial Statements for further discussion of the BP NGL Acquisition. See Note 11 to our Consolidated Financial Statements for further discussion of the PNG Merger. During 2014 and 2013, our general partner s incentive distributions were reduced by approximately $23 million and $15 million, respectively.

Distributions to noncontrolling interests. We paid $3 million and $49 million for distributions to noncontrolling interests during the years ended December 31, 2014 and 2013, respectively. These amounts represent distributions paid on interests in PNG and SLC Pipeline LLC that were not owned by us. The decrease in amounts paid in 2014 is due to our completion of the PNG Merger on December 31, 2013, through which we purchased all of the noncontrolling interests in PNG. See Note 11 to our Consolidated Financial Statements for further discussion of the PNG Merger.

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

Contingencies

For a discussion of contingencies that may impact us, see Note 17 to our Consolidated Financial Statements.

Commitments

Contractual Obligations. In the ordinary course of doing business, we purchase crude oil and NGL from third parties under contracts, the majority of which range in term from thirty-day evergreen to five years with a limited number of contracts extending up to approximately ten years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between purchases on the one hand and sales and future delivery obligations on the other. In addition, we enter into similar contractual obligations in conjunction with our natural gas operations. The table below includes purchase obligations related to these activities. Where applicable, the amounts presented represent the net obligations associated with our counterparties (including giving effect to netting buy/sell contracts and those subject to a net settlement arrangement). We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to entities that we deem creditworthy or who have provided credit support we consider adequate.

Table of Contents

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, 2014 (in millions):

	2015	2016	2017	2018	2019	2020 and Thereafter	Total
Long-term debt, including current maturities and related interest payments (1)	$ 998	$ 604	$ 799	$ 972	$ 1,188	$ 10,605	$ 15,166
Leases (2)	162	151	127	102	78	373	993
Other obligations (3)	392	146	79	42	28	184	871
Subtotal	1,552	901	1,005	1,116	1,294	11,162	17,030
Crude oil, natural gas, NGL and other purchases (4)	6,617	4,457	3,303	1,991	1,304	3,968	21,640
Total	$ 8,169	$ 5,358	$ 4,308	$ 3,107	$ 2,598	$ 15,130	$ 38,670

(1) Includes debt service payments, interest payments due on senior notes and the commitment fee on assumed available capacity under the PAA revolving credit facilities. Although there may be short-term borrowings under the PAA revolving credit facilities and commercial paper program, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no short-term borrowings were outstanding on the facilities or commercial paper program) in the amounts above.

(2) Leases are primarily for (i) surface rentals, (ii) office rent, (iii) pipeline assets and (iv) trucks, trailers and railcars. Includes both capital and operating leases as defined by FASB guidance.

(3) Includes (i) other long-term liabilities, (ii) storage, processing and transportation agreements and (iii) commitments related to our capital expansion projects, including projected contributions for our share of the capital spending of our equity-method investments. Excludes a non-current liability of approximately $32 million related to derivative activity included in Crude oil, natural gas, NGL and other purchases.

(4) Amounts are primarily based on estimated volumes and market prices based on average activity during December 2014. 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 supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil, NGL and natural gas. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the product is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. Additionally, we issue letters of credit to support insurance programs and construction activities. At December 31, 2014 and 2013, we had outstanding letters of credit of approximately $87 million and $41 million, respectively.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements as defined by Item 303 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, 2014 (unaudited, dollars in millions):

Entity	Type of Operation	Our Ownership Interest	Total Entity Assets	Total Cash and Restricted Cash	Total Entity Debt
Settoon Towing, LLC	Barge Transportation Services	50%	$ 352	$	$ 247
BridgeTex Pipeline Company, LLC	Crude Oil Pipeline	50%	$ 888	$ 46	$
Eagle Ford Pipeline LLC	Crude Oil Pipeline	50%	$ 653	$ 11	$
White Cliffs Pipeline, LLC	Crude Oil Pipeline	36%	$ 540	$ 15	$
Butte Pipe Line Company	Crude Oil Pipeline	22%	$ 29	$ 3	$
Frontier Pipeline Company	Crude Oil Pipeline	22%	$ 25	$ 3	$

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

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

Commodity Price Risk

We use derivative instruments to hedge commodity price risk associated with the following commodities:

- *Crude oil*

We utilize crude oil derivatives to hedge commodity price risk inherent in our Supply and Logistics and Transportation segments. Our objectives for these derivatives include hedging anticipated purchases and sales, stored inventory, and storage capacity utilization. We manage these exposures with various instruments including exchange-traded and over-the-counter futures, forwards, swaps and options.

- *Natural gas*

We utilize natural gas derivatives to hedge commodity price risk inherent in our Supply and Logistics and Facilities segments. Our objectives for these derivatives include hedging anticipated purchases and sales and managing our anticipated base gas requirements. We manage these exposures with various instruments including exchange-traded futures, swaps and options.

- *NGL and other*

We utilize NGL derivatives, primarily butane and propane derivatives, to hedge commodity price risk inherent in our Supply and Logistics segment. Our objectives for these derivatives include hedging anticipated purchases and sales and stored inventory. We manage these exposures with various instruments including exchange-traded and over-the-counter futures, forwards, swaps and options.

See Note 12 to our Consolidated Financial Statements for further discussion regarding our hedging strategies and objectives.

Table of Contents

Our policy is to (i) purchase only product for which we have a market, (ii) hedge our purchase and sales contracts so that price fluctuations do not materially affect our operating income and (iii) not acquire and hold physical inventory or other derivative instruments for the purpose of speculating on outright commodity price changes, as these activities could expose us to significant losses.

The fair value of our commodity derivatives and the change in fair value as of December 31, 2014 that would be expected from a 10% price increase or decrease is shown in the table below (in millions):

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
Crude oil	$ (64)	$ 35	$ (34)
Natural gas	(2)	$ (2)	$ 2
NGL and other	257	$ (23)	$ 23
Total fair value	$ 191		

The fair values presented in the table above reflect the sensitivity of the derivative instruments only and do not include the effect of the underlying hedged commodity. Price-risk sensitivities were calculated by assuming an across-the-board 10% increase or decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10% change in near-term commodity 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

Our use of variable rate debt and any forecasted issuances of fixed rate debt expose us to interest rate risk. Therefore, from time to time we use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and, in certain cases, outstanding debt instruments. All of our senior notes are fixed rate notes and thus are not subject to interest rate risk. The majority of our variable rate debt at December 31, 2014, $734 million, is subject to interest rate re-sets, which range up to three months. The average interest rate of 0.3% is based upon rates in effect during the year ended December 31, 2014. The fair value of our interest rate derivatives is a liability of $70 million as of December 31, 2014. A 10% increase in the forward LIBOR curve as of December 31, 2014 would result in an increase of $50 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of December 31, 2014 would result in a decrease of $50 million to the fair value of our interest rate derivatives. See Note 12 to our Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

Currency Exchange Rate Risk

We use foreign currency derivatives to hedge foreign currency exchange rate risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. The fair value of our foreign currency derivatives is a liability of $12 million as of December 31, 2014. A 10% increase in the exchange rate (USD-to-CAD) would result in a decrease of $15 million to the fair value of our foreign currency derivatives. A 10% decrease in the exchange rate (USD-to-CAD) would result in an increase of $16 million to the fair value of our foreign currency derivatives. See Note 12 to our Consolidated Financial Statements for a discussion of our currency exchange rate risk hedging.

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

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

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

None.

Table of Contents

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

Disclosure Controls and Procedures

We maintain written disclosure controls and procedures, which we refer to as our DCP. Our DCP is designed to ensure that information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 (the Exchange Act) is (i) recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and (ii) 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 our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our DCP as of December 31, 2014, the end of the period covered by this report, and, based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our DCP is effective.

Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, our Chief Executive Officer and our Chief Financial Officer, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Our management, including our Chief Executive Officer and our Chief Financial Officer, has evaluated the effectiveness of our internal control over financial reporting as of December 31, 2014. See Management s Report on Internal Control Over Financial Reporting on page F-2 of our Consolidated Financial Statements.

Our independent registered public accounting firm, PricewaterhouseCoopers LLP, assessed the effectiveness of our internal control over financial reporting, as stated in the firm s report. See Report of Independent Registered Public Accounting Firm on page F-3 of our Consolidated Financial Statements.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting during the fourth quarter of 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Certifications

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a) are filed with this report as Exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. 1350 are furnished with this report as Exhibits 32.1 and 32.2.

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

There was no information that was required to be disclosed in a report on Form 8-K during the fourth quarter of 2014 that has not previously been reported.

Table of Contents

PART III

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

Partnership Management and Governance

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

GP LLC manages our operations and activities; however, PAGP effectively controls our business and affairs through the exercise of its rights as the sole and managing member of GP LLC, including its right to appoint certain members to the board of directors of GP LLC. The business and affairs of GP LLC are managed by or under the direction of its board of directors, which we refer to as our board of directors or board . As provided in the Sixth Amended and Restated Limited Liability Company Agreement of GP LLC (the GP LLC Agreement), our board of directors consists of eight members, appointed as follows:

- Three of the members are the same individuals designated to serve on the board of directors of GP Holdings by the three members of GP Holdings that currently hold board designation rights for the GP Holdings board of directors (affiliates of The Energy & Minerals Group, Kayne Anderson Investment Management Inc. and Occidental Petroleum Corporation);
- Four of the members (three of whom must be independent directors eligible to serve on the audit committee) are elected, and may be removed, by PAGP, acting by majority vote through the board of directors of its general partner, GP Holdings; and
- One of the members is the Chief Executive Officer of GP LLC.

Any member of GP Holdings that accumulates an interest in AAP greater than 20% and does not otherwise have a GP Holdings board designation right may designate a GP Holdings director, except that there may be no more than three designated directors serving on the GP Holdings board at any one time. In the event a designated director ceases to serve as a director of the GP Holdings board of directors, such director will be automatically removed as a director of our board; the replacement for such director shall either be (i) the director appointed to the GP Holdings board by a subsequent designating member of GP Holdings or (ii) if there is no such subsequent designating member, an individual elected by PAGP acting by majority vote through the board of directors of GP Holdings.

Our unitholders are limited partners and do not directly or indirectly participate in our management or operation. Unlike holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business or governance. In addition, our partnership agreement limits any fiduciary duties our general partner might owe to our unitholders. As a general partner, our general partner is liable for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Our general partner has the sole discretion to incur indebtedness or other obligations on our behalf on a non-recourse basis to the general partner. Our general partner has in the past exercised such discretion, in most instances involving payment liability, and intends to exercise such discretion in the future.

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 currently require coincidence of the offices. However, pursuant to the terms of the GP LLC Agreement, if and when our board of directors elects a successor to

Table of Contents

our current CEO, by majority vote our board of directors may determine to separate the offices of CEO and Chairman of the Board. We do not have a lead independent director.

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

Non-Management Executive Sessions and Shareholder Communications

Non-management directors meet in executive session in connection with each regular board meeting. On a rotating basis (determined alphabetically by last name), one of the non-management directors acts as presiding director at each such regularly scheduled executive session.

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

Independence Determinations and Audit Committee

Because we are a limited partnership, the listing standards of the NYSE do not require that we or our general partner have a majority of independent directors on the board, or that we establish or maintain a nominating or compensation committee of the board. We are, however, required to have an audit committee consisting of at least three members, all of whom are required to be independent as defined by the NYSE.

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

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

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

Compensation Committee

Although not required by NYSE listing standards, we have a compensation committee that reviews and makes recommendations to the board regarding the compensation for the executive officers and administers our equity compensation plans for officers and key employees. The charter of our compensation committee is available on our website. See Meetings and Other Information for information on how to access or obtain copies of this charter. The compensation committee currently consists of Messrs. Petersen, Raymond and Sinnott. 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 2014. The compensation committee has delegated

Table of Contents

limited authority to the CEO to administer our long-term incentive plans with respect to employees other than executive officers.

Governance and Other Committees

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

In addition, our partnership agreement allows 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 committee will typically consist of a minimum of two independent, non-employee members of our board. Our partnership agreement provides that 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 Review, Approval or Ratification of Transactions with Related Persons.

Meetings and Other Information

During the last fiscal year, our board of directors had five meetings, our audit committee had ten meetings, our compensation committee had one meeting and our governance committee had one meeting. All directors have access to members of management, and a substantial amount of information transfer and informal communication occurs between meetings. None of our directors attended fewer than 75% of the aggregate number of meetings of the board of directors and committees of the board on which the director served.

As discussed above, GP LLC manages our operations and activities, and GP LLC is managed by or under the direction of its board of directors, whose members are either designated by certain members of GP Holdings or appointed by PAGP, as the sole member of GP LLC acting through the GP Holdings board of directors. 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 regular annual meetings of unitholders for the purpose of electing directors or soliciting approval of any other routine matters.

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 applies to our principal executive officer, principal financial officer and principal accounting officer), are available under the Structure and Governance tab in the Investor Relations section of our Internet website at *http://www.plainsallamerican.com*. We intend to disclose any amendment to or waiver of the Code of Ethics for Senior Financial Officers and any waiver of our Code of Business Conduct on behalf of an executive officer or director either on our Internet website or in an 8-K filing.

Table of Contents

Audit Committee Report

The audit committee of our board of directors 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 Public Company Accounting Oversight Board Auditing Standard No. 16, Communications with Audit Committees. The audit 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, 2014 for filing with the SEC.

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

Directors, Executive Officers and Other Officers

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

Table of Contents

Name	Age (as of 12/31/14)	Position(1)
Greg L. Armstrong*(2)	56	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis*	57	President and Chief Operating Officer
Mark J. Gorman*	60	Executive Vice President Operations and Business Development
Phillip D. Kramer*	58	Executive Vice President
Richard K. McGee*	53	Executive Vice President, General Counsel and Secretary
John R. Rutherford*	54	Executive Vice President
Al Swanson*	50	Executive Vice President and Chief Financial Officer
John P. vonBerg*	60	Executive Vice President Commercial Activities
W. David Duckett*	59	President, Plains Midstream Canada
Lawrence J. Dreyfuss	60	Senior Vice President, General Counsel Commercial & Litigation and Assistant Secretary
Alfred A. Lindseth	45	Senior Vice President Technology, Process & Risk Management
Daniel J. Nerbonne	57	Senior Vice President Engineering
Troy Baker	42	Vice President, Crude Commercial, Plains Midstream Canada
Jason Balasch	46	Executive Vice President, NGL Commercial and Facilities, Plains Midstream Canada
Samuel N. Brown	58	Vice President Pipeline Business Development
Kevin L. Cantrell	54	Vice President Internal Audit
David Craig	57	Executive Vice President and Chief Financial Officer, Plains Midstream Canada
Ralph R. Cross	59	Vice President, Corporate Development, Plains Midstream Canada
Brad Deets	41	Vice President, LPG Commercial, Plains Midstream Canada
Roger D. Everett	69	Vice President Human Resources
James Ferrell	44	Vice President Supply Chain Management
Bill Forward	48	Vice President, Finance, Plains Midstream Canada
James B. Fryfogle	63	Vice President Refinery Supply
M.D. (Mike) Hallahan	54	Vice President, Bulk Commodities Transportation, Plains Midstream Canada
Chris Herbold*	42	Vice President Accounting and Chief Accounting Officer
Jim G. Hester	55	Vice President Natural Gas Gathering and Processing
Keith Jalbert	49	Vice President Commercial Activities
Richard Jensen	61	Executive Vice President, Operations, Plains Midstream Canada
Christopher M. Kean	50	Vice President, Engineering, Plains Midstream Canada
John Keffer	55	Vice President Terminals
Charles Kingswell-Smith	63	Vice President Finance
Sterling Koch	45	Vice President, Health, Safety, Environment & Regulatory, Plains Midstream Canada
Dwayne Koehn	41	Vice President Engineering
Mike Mikuska	46	Vice President, Pipelines Development and Logistics, Plains Midstream Canada
George N. Polydoros	51	Vice President Land and Office Services
Tyler Rimbey	48	Executive Vice President, Crude Oil Commercial and Pipelines, Plains Midstream Canada
Robert M. Sanford	65	Vice President Lease Supply
David Schwarz	45	Vice President, Human Resources, Plains Midstream Canada
Scott Sill	52	Vice President, Operations, Plains Midstream Canada
Phil Smith	56	Vice President Operations
Sharon S. Spurlin	49	Vice President and Treasurer
Troy E. Valenzuela	53	Vice President Environmental, Health and Safety
Walter van Zanten	58	Vice President Tax
Sandi Wingert	44	Vice President, Corporate Services, Plains Midstream Canada
Bernard (Ben) Figlock(2)	54	Director
Everardo Goyanes	70	Director and Member of Audit** Committee

Table of Contents

Gary R. Petersen	68	Director and Member of Compensation and Governance Committees
John T. Raymond(2)	44	Director and Member of Compensation Committee
Robert V. Sinnott(2)	65	Director and Member of Compensation** Committee
J. Taft Symonds	75	Director and Member of Audit and Governance** Committees
Christopher M. Temple	47	Director and Member of Audit Committee

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

** Indicates chairman of committee.

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

(2) The GP LLC Agreement specifies that the Chief Executive Officer of the general partner will be a member of the board of directors. Under the GP LLC Agreement, three of the members of GP Holdings each have the right to appoint one director each to the GP Holdings board of directors and each such appointee is automatically appointed as a member of our board of directors. Mr. Raymond is serving as a member of our board of directors by virtue of his appointment as a member of the board of directors of GP Holdings by EMG Investment, LLC (EMG), of which he is the sole member of the general partner of its manager. Mr. Sinnott is serving as a member of our board of directors by virtue of his appointment as a member of the board of directors of GP Holdings by KAFU Holdings, L.P., which is affiliated with Kayne Anderson Investment Management, Inc., of which he is President. Mr. Figlock is serving as a member of our board of directors by virtue of his appointment as a member of the board of directors of GP Holdings by Occidental Holding Company (Pipeline), Inc., a subsidiary of Occidental Petroleum Corporation (Oxy), of which he is Vice President and Treasurer. The remaining directors were elected by PAGP, as the sole member of GP LLC acting through the board of GP Holdings. See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters Beneficial Ownership of General Partner Interest.

Greg L. Armstrong has served as Chairman of the Board and Chief Executive Officer since our formation in 1998. He has also served as a director of our general partner or former general partner since our formation. In addition, he was President, Chief Executive Officer and director of Plains Resources Inc. from 1992 to May 2001. He previously served Plains Resources as: President and Chief Operating Officer from October to December 1992; Executive Vice President and Chief Financial Officer from June to October 1992; Senior Vice President and Chief Financial Officer from 1991 to 1992; Vice President and Chief Financial Officer from 1984 to 1991; Corporate Secretary from 1981 to 1988; and Treasurer from 1984 to 1987. Mr. Armstrong is a director of the Federal Reserve Bank of Dallas, and a director of National Oilwell Varco, Inc. Mr. Armstrong is also Chairman, Chief Executive Officer and Director of PAA GP Holdings LLC, which is the general partner of Plains GP Holdings, L.P. Mr. Armstrong is also a member of the advisory board of the Maguire Energy Institute at the Cox School of Business at Southern Methodist University, the National Petroleum Council and the Foundation for The Council on Alcohol and Drugs Houston.

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

104

Mark J. Gorman has served as Executive Vice President Operations and Business Development since February 2013 and served as Senior Vice President Operations and Business Development from August 2008 until February 2013. 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, and a managing director of Eagle Ford Pipeline. Mr. Gorman also serves as Executive Vice President Operations and Business Development of PAA GP Holdings LLC, which is the general partner of Plains GP Holdings, L.P.

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. Mr. Kramer also serves as Executive Vice President of PAA GP Holdings LLC, which is the general partner of Plains GP Holdings, L.P.

Richard K. McGee has served as Executive Vice President, General Counsel and Secretary since February 2013. He served as Vice President, General Counsel and Secretary from March 2012 until February 2013 and served as Vice President and Deputy General Counsel from August 2011 through March 2012. He also served as Vice President Legal and Business Development of PAA s natural gas storage business from September 2009 through March 2012. From January 1999 to July 2009, he was employed by Duke Energy, serving as President of Duke Energy International from October 2001 through July 2009 and serving as general counsel of Duke Energy Services from January 1999 through September 2001. He previously spent 12 years at Vinson & Elkins L.L.P., where he was a partner with a focus on acquisitions, divestitures and development work for various clients in the energy industry. Mr. McGee also serves as Executive Vice President, General Counsel and Secretary of PAA GP Holdings LLC, which is the general partner of Plains GP Holdings, L.P.

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

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

Table of Contents

John P. vonBerg has served as Executive Vice President Commercial Activities since February 2014. Previously he served as Senior Vice President Commercial Activities from August 2008 until February 2014, 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. Mr. vonBerg also serves as Executive Vice President Commercial Activities of PAA GP Holdings LLC, which is the general partner of Plains GP Holdings, L.P.

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

Lawrence J. Dreyfuss has served as Senior Vice President, General Counsel Commercial and Litigation and Assistant Secretary since February 2013, and served as Vice President, General Counsel Commercial & Litigation and Assistant Secretary from August 2006 until February 2013. 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.

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.

Daniel J. Nerbonne has served as Senior Vice President Engineering since February 2013 and as Vice President Engineering from February 2005 until February 2013. 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.

Troy Baker has served as Vice President, Crude Commercial of Plains Midstream Canada since September 2014 and is responsible for Crude Oil and Diluent Supply and Trading in addition to trading Crude Oil-by-Rail. Mr. Baker has been with PMC for over seven years, serving most recently as Director of Crude Oil and Diluent Trading. Prior to joining PMC, he worked with Husky Energy for 11 years where he served in various capacities, finishing as Manager of Crude Oil Trading. Mr. Baker also has field experience working in Facility Operations with Amoco Canada Petroleum.

Jason Balasch has served as Executive Vice President, NGL Commercial and Facilities of Plains Midstream Canada since January 2015 and is responsible for overseeing all commercial activities associated with PMC s NGL business including supply, logistics, facilities, business development and joint ventures. He previously served as Senior Vice President, LPG Commercial and Facilities of PMC from September 2013 through December 2014 and as Vice President of LPG of PMC from September 2011 until September 2013. Prior to joining PMC, he was with Enterprise Products Partners L.P. from June 2000 to August 2011, where he served in various capacities, most recently as Vice President, U.S. Gulf Coast Gathering & Processing in their Houston, Texas office. Mr. Balasch has also worked for Chevron and TransCanada Corporation in both engineering and business development roles.

Table of Contents

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

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

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

Ralph R. Cross has served as Vice President, Corporate Development of Plains Midstream Canada since July 2012. He previously served as Vice President Corporate Development and Transportation Services of Plains Midstream Canada from July 2001 until July 2012. Mr. Cross was previously with CANPET since 1992, where he served in various capacities, including most recently as Vice President of Business Development.

Brad Deets has served as Vice President, LPG Commercial of Plains Midstream Canada since September 2013. He served as Vice President of Strategic Planning from June 2013 through August 2013, and previously served as Director of Strategic Planning. He has served in a number of roles at PMC including butane trading, risk management and acquisitions. Prior to joining PMC, Mr. Deets worked with CANPET Energy Group Inc. for a number of years, focusing on crude oil trading.

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

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

Bill Forward has served as Vice President, Finance of Plains Midstream Canada since September 2013. Prior to joining PMC, he held senior management positions in accounting and finance for several midstream energy companies, most recently serving as Corporate Controller for Pembina Pipelines Corp. Previously, he was Vice-President at Provident Energy Ltd. and served in financial reporting and accounting roles at ENMAX, TransCanada and PricewaterhouseCoopers.

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 Plains 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.

Table of Contents

M.D. (Mike) Hallahan has served as Vice President, Bulk Commodities Transportation since August 2014. He previously served as Vice President, Crude Oil and Truck Transportation of Plains Midstream Canada from February 2004 to August 2014 and as Managing Director, Facilities from July 2001 to February 2004. He was previously with CANPET where he served in various capacities since 1996, most recently as General Manager, Facilities.

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

Jim G. Hester has served as Vice President Natural Gas Gathering and Processing since August 2011. He previously served as Vice President Acquisitions since March 2002. Prior to joining PAA, 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.

Keith Jalbert has served as Vice President of Commercial Activities since December 2014. He previously served as Managing Director of Commercial Activities from 2008 until December 2014, and as a Trader from 2002 through 2008. Before joining Plains, he was employed by Genesis Energy as a Crude Oil Trader. Prior to that, he held various analyst, scheduling, trading and management positions with Basis Petroleum and Phibro Energy.

Richard Jensen has served as Executive Vice President, Operations of Plains Midstream Canada since October 2012. Prior to joining PMC, Mr. Jensen worked with Nexen Petroleum for over 27 years, where he served in various leadership capacities, most recently as Vice President, Middle East, South America and Africa. Mr. Jensen has also worked in executive leadership roles at Canadian Occidental Petroleum and Canadian Nexen Chemicals.

Christopher M. Kean has served as Vice President, Engineering of Plains Midstream Canada since September 2012. He has over 25 years of experience in global projects and operations across the oil and gas, chemical and oil sands sectors. Prior to joining PMC, Mr. Kean worked with Enbridge Pipelines for over four years, where he served in various capacities, most recently as Project Director for the Cabin Gas Plant project. Mr. Kean has also worked in both engineering and project management leadership roles for Canadian Natural Resources Limited (11 years), Petro-Canada, and Amoco Chemical and Production Companies.

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

Charles Kingswell-Smith has served as Vice President Finance since October 2014 and served as Vice President and Treasurer from August 2008 until October 2014. 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.

Sterling Koch has served as Vice President, Health, Safety, Environment & Regulatory of Plains Midstream Canada since January 2013. He is responsible for providing strategic direction and oversight to the environment, health & safety, regulatory and land activities of our Canadian operations. Mr. Koch brings over 20 years of energy industry experience, including regulatory and legal affairs, commercial operations, compliance and security. Prior to joining PMC, Mr. Koch worked with TransAlta for over 14 years, where he served in various vice president roles including regulatory and legal affairs, commercial management and business development. He also brings to PMC a background as legal counsel, originating from his days with Western Gas Marketing, Northridge Petroleum and TransCanada.

Dwayne Koehn has served as Vice President Engineering since February 2014. Mr. Koehn previously served as Managing Director of Engineering from July 2008 to February 2014, and as Director of Engineering from September 2005 to June 2008. He initially joined Plains in 2004 in connection with the acquisition of Link Energy where he was a Manager of Engineering. Mr. Koehn has also served in various manager and director roles with Koch Industries and PF Net Construction.

Mike Mikuska has served as Vice President, Pipelines Development and Logistics of Plains Midstream Canada since August 2012. He previously served as Vice President of Business Development Crude Oil of Plains Midstream Canada from September 2008 to August 2012. Mr. Mikuska has been with PMC and its predecessor CANPET since 1995 and has served in various commercial and development roles over that time.

George N. Polydoros has served as Vice President Land and Office Services since February 2013. He served as Managing Director Land and Office Services from April 2011 until February 2013. Prior to joining PAA, Mr. Polydoros was a partner at the law firm of Mayer Brown. Before joining Mayer Brown, he worked as an attorney at American General Corporation (now part of AIG) and Bracewell & Giuliani.

Tyler Rimbey has served as Executive Vice President, Crude Oil Commercial and Pipelines of Plains Midstream Canada since July 2014 and is responsible for overseeing commercial areas of the business including crude oil trading, crude oil business development, pipelines and logistics, acquisitions and rail and truck transportation. Mr. Rimbey brings over 25 years of energy industry experience, including commodity trading, marketing and business development. Prior to joining PMC, Mr. Rimbey worked with Platino Energy Corp., serving as Vice President of Business Development. He has also worked in executive and senior leadership roles with BP Canada Energy Trading Company, BP Energy Company, Goldman Sachs and Shell in Canada, the U.S. and United Kingdom.

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

David Schwarz has served as Vice President, Human Resources of Plains Midstream Canada since October 2012. He previously served as Vice President of Human Resources and Corporate Communications of Plains Midstream Canada from February 2011 to October 2012. He joined Plains Midstream Canada in August 2009 and brings over 18 years of experience to this role. Prior to joining PMC, Mr. Schwarz held various senior human resources roles in Calgary, and most recently served as Senior Manager, Human Resources in the ATCO Group of Companies. He has also gained experience working for such companies as Fluor Daniel, Manalta Coal and Superior Propane.

Scott Sill has served as Vice President, Operations of Plains Midstream Canada since September 2013 and is responsible for PMC s crude oil, NGL and LPG operations. He previously served as Vice President of LPG Operations from March 2010 until September 2013. He joined Plains Midstream Canada in April 2006 through PAA s acquisition of the Shafter gas liquids processing facility. Prior to his most recent role as Managing Director of U.S. and Canadian LPG Operations, Mr. Sill performed the role of West Coast District Superintendent, overseeing an LPG isomerization/hydrotreating facility, salt cavern terminal, fractionation plant and various storage terminals. Mr. Sill brings over 25 years of LPG operations experience to this role.

Table of Contents

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

Sharon S. Spurlin has served as Vice President and Treasurer since October 2014. Before re-joining PAA, Ms. Spurlin served as Chief Financial Officer of PetroLogistics from 2009 until 2014. She originally joined PAA in 2002 and served as Director of Internal Audit and as Assistant Treasurer until 2009.

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.

Walter van Zanten has served as Vice President Tax since February 2013. He served as Director of Tax from December 2008 until February 2013. Before joining PAA, Mr. van Zanten worked in various leadership and functional capacities for Chimerical, Inc., El Paso Corp., Tenneco Energy, The Coastal Corporation, Tangram Transmission Corp. and Arthur Young.

Sandi Wingert has served as Vice President, Corporate Services of Plains Midstream Canada since September 2013. She served as Vice President of Accounting of PMC from February 2008 until September 2013. She has been with PMC and its predecessor CANPET acting as Controller since 2000. Prior to joining our Canadian operations, she held various accounting roles with Koch Petroleum and Ernst & Young.

Bernard (Ben) Figlock has served as a director of our general partner since January 2015. Mr. Figlock currently serves as Vice President and Treasurer at Oxy, where he directs and oversees management of Oxy s treasury and risk management functions including finance, investments, insurance and operational risk, commodities trading credit and market risk, and currencies. Mr. Figlock joined Oxy in 1987, advancing to positions of increasing responsibility in Internal Audit, Corporate Finance Planning & Analysis, Corporate Development, and Treasury. He also serves as a director of PAA GP Holdings LLC, which is the general partner of Plains GP Holdings, L.P. Mr. Figlock holds a BS in Accounting from Wake Forest University and an MBA from Loyola Marymount University. We believe that Mr. Figlock s financial and analytical background provides the board a distinctive and valuable perspective.

Everardo Goyanes has served as a director of our general partner or former general partner since May 1999. He is Founder of Ex Cathedra LLC (a consulting firm). Mr. Goyanes served as Chairman of Liberty Natural Resources from April 2009 until August 2011. From May 2000 to April 2009, he was President and Chief Executive Officer of Liberty Energy Holdings, LLC (an energy investment firm). From 1999 to May 2000, he was a financial consultant specializing in natural resources. From 1989 to 1999, he was Managing Director of the Natural Resources Group of ING Barings Furman Selz (a banking firm). He was a financial consultant from 1987 to 1989 and was Vice President Finance of Forest Oil Corporation from 1983 to 1987. From 1967 to 1982, Mr. Goyanes served in various financial and management capacities at Chase Bank, where his major emphasis was international and corporate finance to large independent and major oil companies. Mr. Goyanes also serves as a director and as chairman of the audit committee of PAA GP Holdings LLC, which is the general partner of Plains GP Holdings, L.P. Mr. Goyanes received a BA in Economics from Cornell University and a Masters degree in Finance (honors) from Babson Institute. The board of directors has determined that Mr. Goyanes is independent under applicable NYSE rules and qualifies as an Audit Committee Financial Expert.   Mr. Goyanes qualifications as an Audit Committee Financial Expert are supplemented by extensive experience comprising direct involvement in the energy sector over a span of more than 30 years. We believe that this experience, coupled with the leadership qualities demonstrated by his executive background bring important experience and skill to the board.

Gary R. Petersen has served as a director of our general partner since June 2001. Mr. Petersen is a Managing Partner 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

Table of Contents

Directors of Nicklos Oil & Gas Company from 1979 to 1984. He served from 1970 to 1971 in the U.S. Army as a First Lieutenant in the Finance Corps and as an Army Officer in the Army Security Agency. He is a member of the Independent Petroleum Association of America, the Houston Producers Forum and the Petroleum Club of Houston. Mr. Petersen holds BBA and MBA degrees in finance from Texas Tech University. The board of directors has determined that Mr. Petersen is independent under applicable NYSE rules. Mr. Petersen has been involved in the energy sector for a period of more than 35 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 $18 billion of energy-related investments. In tandem with the leadership qualities evidenced by his executive background, we believe that Mr. Petersen brings numerous valuable attributes to the board.

John T. Raymond has served as a director of our general partner since December 2010. Mr. Raymond is an owner and founder of The Energy & Minerals Group, which is the management company for a series of specialized private equity funds. EMG was founded in 2006 and focuses on investing across various facets of the global natural resource industry including the upstream and midstream segments of the energy complex. EMG has approximately $17.1 billion of regulatory assets under management and approximately $8.1 billion in commitments have been allocated across the energy sector since inception. Previous to that time, Mr. Raymond held leadership positions with various energy companies, including President and CEO of Plains Resources Inc. (the predecessor entity for Vulcan Energy), President and Chief Operating Officer of Plains Exploration and Production Company and Director of Development for Kinder Morgan, Inc. Mr. Raymond has been a direct or indirect owner of PAA s general partner since 2001 and served on the board of PAA s general partner from 2001 to 2005. Mr. Raymond also serves as a director of PAA GP Holdings LLC, which is the general partner of Plains GP Holdings, L.P. He serves on numerous other boards, including NGL Energy Holdings LLC, the general partner of NGL Energy Partners, L.P., and Tallgrass MLP GP, LLC, the general partner of Tallgrass Energy Partners, L.P. Mr. Raymond received a BSM degree from the A.B. Freeman School of Business at Tulane University with dual concentrations in finance and accounting. We believe that Mr. Raymond s experience with investment in and management of a variety of upstream and midstream assets and operations provides a valuable resource to the board.

Robert V. Sinnott has served as a director of our general partner or former general partner since September 1998. Mr. Sinnott is President, Chief Executive Officer and Chief Investment Officer of Kayne Anderson Capital Advisors, L.P. (an investment management firm). He also served as a Managing Director from 1992 to 1996 and as a Senior Managing Director from 1996 until assuming his CEO role in 2010. He is also President of Kayne Anderson Investment Management, Inc., the general partner of Kayne Anderson Capital Advisors, L.P. Mr. Sinnott served as a director of Kayne Anderson Energy Development Company from 2006 through June 2013. He was Vice President and Senior Securities Officer of the Investment Banking Division of Citibank from 1986 to 1992, and previously held positions with United Energy Resources, a pipeline company, and Bank of America in its oil and gas finance department. Mr. Sinnott also serves as a director of California Resources Corporation and PAA GP Holdings LLC, which is the general partner of Plains GP Holdings, L.P. 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 $23 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.

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 Free Flow Wines LLC. Mr. Symonds previously served as a director of Tetra Technologies Inc. and Schilling Robotics LLC, where he served on the audit committee. 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.

Table of Contents

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

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires directors, executive officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC and the NYSE initial reports of ownership and reports of changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms that they file. Such reports are accessible on or through our Internet website at *http://www.plainsallamerican.com.*

Based solely upon a review of the copies of Forms 3, 4 and 5 furnished to us, or written representations from certain reporting persons that no Forms 5 were required, we believe that our executive officers and directors complied with all filing requirements with respect to transactions in our equity securities during 2014.

Table of Contents

Item 11. *Executive Compensation*

Compensation Committee Report

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

In fulfilling its oversight responsibilities, the compensation committee reviewed and discussed with management the compensation discussion and analysis contained in this Annual Report on Form 10-K. Based on those reviews and discussions, the compensation committee recommended to the board of directors that the compensation discussion and analysis be included in the Annual Report on Form 10-K for the year ended December 31, 2014 for filing with the SEC.

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

Compensation Committee Interlocks and Insider Participation

Messrs. Petersen, Raymond and Sinnott currently serve on the compensation committee and served on the compensation committee throughout 2014. Vicky Sutil, a former director, also served on the compensation committee during 2014. During 2014, none of the members of the compensation committee was an officer or employee of us or any of our subsidiaries, or served as an officer of any company with respect to which any of our executive officers served on such company s board of directors. In addition, none of the members of the compensation committee are former employees of ours or any of our subsidiaries. Mr. Raymond is associated with EMG and Mr. Sinnott is associated with Kayne Anderson and its affiliates, and, during 2014, Ms. Sutil was associated with Oxy. We have relationships with these entities. See Item 13. Certain Relationships and Related Transactions, and Director Independence Transactions with Related Persons Other.

Compensation Discussion and Analysis

Background

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

Objectives

Since our inception, we have employed a compensation philosophy that emphasizes pay for performance, both on an individual and entity level, and places the majority of each Named Executive Officer s (defined in the Summary Compensation Table below) compensation at risk. The primary long-term measure of our performance is our ability to increase our sustainable quarterly distribution to our unitholders. We believe our pay-for-performance approach aligns the interests of our executive officers with that of our equity holders, and at the same time enables us to maintain a lower level of base overhead in the event our operating and financial performance is below expectations. Our executive compensation is designed to attract and retain individuals with the background and skills necessary to successfully execute our business model in a demanding environment, to motivate those individuals to reach near-term and long-term goals in a way that aligns their interest with that of our unitholders, and to reward success in reaching such goals. We use three primary elements of compensation to fulfill that design salary, cash bonus and long-term equity incentive awards. Cash bonuses and equity incentives (as opposed to salary) represent the performance driven elements. They are also flexible in application and can be tailored to meet our objectives. The determination of specific individuals cash bonuses is based on their relative contribution to achieving or exceeding annual goals and the determination of specific individuals long-term incentive awards is based on their expected contribution in respect of longer term performance objectives. We do not maintain a defined benefit or pension plan for our executive officers as we believe such plans primarily reward longevity and not performance. We provide a basic benefits package generally to all employees, which includes a 401(k) plan and health, disability and life insurance. In instances considered necessary for the execution of their job responsibilities, we also reimburse certain of our Named Executive Officers and other employees for club dues and similar expenses. We consider these benefits and reimbursements to be typical of other employers, and we do not believe they are distinctive of our compensation program.

Elements of Compensation

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

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

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

In 2007, the owners of AAP authorized the creation of Class B units of AAP (AAP Management Units), each of which represents a profits interest in AAP, and authorized GP LLC s compensation committee to issue grants of AAP Management Units to create additional long-term incentives for our management designed to attract talent and encourage retention over an extended period of time. The entire economic burden of the AAP Management Units is borne solely by AAP, and does not impact our cash or units outstanding.

The AAP Management Units are subject to restrictions on transfer and generally become incrementally earned (entitled to receive a portion of the distributions that would otherwise be paid to holders of AAP units) upon achievement of certain performance thresholds, which are aligned with the interests of our common unitholders. As of February 17, 2015, 100% of the outstanding AAP Management Units granted in 2007, 2009, 2010 and 2011 had been earned, 75% of the AAP Management Units granted in 2013 had been earned (or will be earned within 180 days), and 25% of the AAP Management Units granted in 2014 will be earned within 180 days. No AAP Management Units were granted in 2008 or 2012.

To encourage retention following achievement of these performance benchmarks, AAP retained a call right to purchase any earned AAP Management Units at a discount to fair market value that is exercisable upon the termination of a holder s employment with GP LLC and its affiliates (other than a termination without cause or by the employee for good reason) prior to certain stated dates. If a holder of an AAP Management Unit remains employed past such designated date (or prior to such date is terminated without cause or quits for good reason), any earned units are no longer subject to the call right and are deemed to have vested. The applicable designated dates for the various AAP Management Unit grants range from January 1, 2016 for AAP Management Units granted in

Table of Contents

2007 to January 1, 2022 for AAP Management Units granted in 2014. In order to encourage retention, the size of the discount to fair market value reflected in the potential call right purchase price decreases over time pursuant to a formula set forth in each AAP Management Unit grant agreement. AAP Management Unit grants also provide that all earned AAP Management Units and a portion of any unearned and unvested AAP Management Units will vest upon a change of control. All earned AAP Management Units will also vest if AAP does not timely exercise its call right.

If at any time after December 31, 2015 the PAGP Class A shares are publicly traded, each vested AAP Management Unit may be converted into AAP units and a like number of PAGP Class B shares based on a conversion ratio calculated in accordance with the AAP limited partnership agreement (which conversion ratio will not be more than one-to-one and was approximately 0.925 AAP units and PAGP Class B shares for each AAP Management Unit as of December 31, 2014 and approximately 0.930 as of February 17, 2015). Following any such conversion, the resulting AAP units and PAGP Class B shares are exchangeable for PAGP Class A shares on a one-for-one basis as provided in the PAGP limited partnership agreement. See Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner AAP Management Units.

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 AAP Management 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 AAP Management Units subject to AAP s call right, serve as near-term retention tools. Longer-term retention is facilitated by the minimum service periods of up to five years associated with phantom unit awards, the long-term vesting profile of the AAP Management 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 GP LLC s compensation committee in reviewing and making recommendations, a compensation tally sheet is prepared by GP LLC s CEO and General Counsel and provided to the compensation committee.

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

We believe our compensation program has been instrumental in our achievement of stated objectives. Over the five-year period ended December 31, 2014, our annual distribution per common unit has grown at a compound annual rate of 7.5% and the total return realized by our unitholders for that period averaged approximately 20.4% per annum. During this period, we have enjoyed a very high rate of retention among executive officers.

Application of Compensation Elements

Salary. We do not make systematic annual adjustments to the salaries of our Named Executive Officers. We do, however, make salary adjustments as necessary to maintain hierarchical relationships among senior management levels after new senior management members are added to keep pace with our overall growth. Since the date of our initial public offering in 1998 (or date of employment, if later) through December 31, 2014,

Table of Contents

Messrs. Armstrong, Pefanis and vonBerg have each received one salary adjustment, Mr. Duckett has received small salary adjustments in line with other Canadian personnel, and Mr. Swanson has received four salary adjustments in connection with taking on increasing responsibilities and promotions.

Annual Discretionary Bonuses. Annual discretionary bonuses are determined based on our performance relative to our annual plan forecast and public guidance (typically provided quarterly in conjunction with release of earnings), our distribution growth targets, and other quantitative and qualitative goals established at the beginning of each year. Such annual objectives are discussed and reviewed with the board of directors in conjunction with the review and authorization of the annual plan.

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

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

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

U.S. Bonus based on Adjusted EBITDA. Mr. vonBerg and certain other members of our U.S.-based senior management team are directly involved in activities that generate partnership earnings. These individuals, along with other employees in our marketing and business development groups participate in a quarterly bonus pool, the size of which is based on adjusted EBITDA, which directly rewards for quarterly performance the commercial and asset managing employees who participate. This quarterly incentive provides a direct incentive to optimize quarterly performance even when, on an annual basis, other factors might negatively affect bonus potential. The size of the bonus pool, and the allocation of quarterly bonus amounts among all participants based on relative contribution, is recommended by Mr. Pefanis and reviewed, modified and approved by Mr. Armstrong, as appropriate. Messrs. Pefanis and Armstrong do not participate in the quarterly bonus pool. The quarterly bonus amounts for

Table of Contents

Mr. vonBerg are taken into consideration in determining the recommended annual discretionary bonus submitted by the CEO to the compensation committee.

Annual Bonus and Quarterly Bonus based on Adjusted EBITDA (Canada). Substantially all of the personnel employed by Plains Midstream Canada (including Mr. Duckett) or involved in Canadian operations participate in a bonus pool under a program established at the time of our entry into Canada in 2001 in connection with the CANPET acquisition. The program encompasses a bonus pool consisting of 10% of adjusted EBITDA for Canadian-based operations (reduced by the carrying cost of inventory in excess of base-level requirements and by the cost of capital associated with growth capital and acquisitions). Participation in the program is recommended by Mr. Duckett and reviewed, adjusted if warranted, and approved by Mr. Pefanis. Mr. Pefanis does not participate in the bonus pool. Mr. Duckett receives a quarterly bonus equal to approximately 40% of his participation level for the first three fiscal quarters of the year. He receives an annual bonus consisting of 60% of his participation in the first three quarters and 100% of his participation in the fourth quarter.

Long-Term Incentive Awards. We do not make systematic annual grants of phantom unit awards to our Named Executive Officers. Instead, our objective is to time the granting of awards such that the creation of new long-term incentives coincides with the satisfaction of performance thresholds under existing awards. Thus, performance is rewarded by relatively greater frequency of awards, and lack of performance by relatively lesser frequency of awards. Generally, we believe that a grant cycle of approximately three years (and extended time-vesting requirements) provides a balance between a meaningful retention period for us and a visible, reachable reward for the executive officer. Achievement of performance targets does not shorten the minimum service period requirement. If top performance targets on outstanding awards are achieved in the early part of this cycle, new awards are granted with higher performance thresholds, and the minimum service periods of the new awards are generally synchronized with the remaining time-vesting requirements of outstanding awards in a manner designed to encourage extended retention of our Named Executive Officers. Accordingly, these new arrangements inherently take into account the value of awards where performance levels have been achieved but have not yet vested due to ongoing service period requirements, but do not take into consideration previous awards that have fully vested.

As an additional means of providing longer-term, performance-based officer incentives that require extended periods of employment to realize the full benefit, in 2007 the owners of AAP authorized the creation of AAP Management Units (each of which represents a profits interest in AAP), which the compensation committee of GP LLC is authorized to administer. See Elements of Compensation Long-Term Incentives. These AAP Management Units are limited to 52,125,935 authorized units, of which approximately 49,172,830 were outstanding as of December 31, 2014 pursuant to individual restricted unit agreements between AAP and certain members of management. As of December 31, 2014 our Named Executive Officers held 28,931,571 of the restricted AAP Management Units. The remaining available AAP Management Units are administered at the discretion of the compensation committee (subject to limited authority delegated to the CEO to approve awards to employees other than executive officers) 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 2014

At the beginning of 2014, we established four public goals with paraphrased versions of these goals overlapping three of our five internal goals.

The four public goals for the year were to:

1. Deliver operating and financial performance in line with or above guidance;

2. Successfully execute our 2014 capital program and set the stage for growth in 2015 and beyond;

3. Increase our November 2014 annualized distribution level by 10% over the November 2013 annualized distribution level; and

4. Selectively pursue strategic and accretive acquisitions.

Table of Contents

Additionally, our internal qualitative goals included (a) advancing multi-year programs and initiatives and preparing the organization for future growth, and (b) continuing to promote a culture of safety and environmental responsibility throughout the organization.

In general, we substantially achieved all of these goals.

- Our adjusted EBITDA slightly exceeded, and our distributable cash flow was in line with, the midpoint of our 2014 guidance furnished in our February 5, 2014 Form 8-K;

- We executed a $2.0 billion expansion capital program timely and cost effectively, and advanced, refined and expanded our portfolio of organic growth projects, setting up a 2015 program of approximately $1.85 billion;

- We completed the acquisition of a 50% interest in BridgeTex Pipeline LLC for $1.1 billion;

- We increased our annualized distribution rate by 10% to $2.64 per common unit, while maintaining distribution coverage of approximately 111%;

- We executed multiple financings that enabled us to fund our expansion capital expenditures while maintaining solid financial strength and liquidity, including raising an aggregate of approximately $3.5 billion of long-term debt and equity capital, extending the maturities of our bank credit facilities, increasing our commercial paper program to $3.0 billion and initiating efforts to arrange a $1.0 billion 364-day credit facility to further enhance liquidity; and

- We executed multiple initiatives to sustain the organization, prepare it for future growth and promote a culture of safety and environmental responsibility.

For 2014, the elements of compensation were applied as described below.

Salary. No salary adjustments for Named Executive Officers were recommended or made in 2014.

Cash Bonuses. Based on the CEO s annual performance review and the individual performance of each of our Named Executive Officers, the compensation committee recommended to the board of directors and the board of directors approved the annual bonuses reflected in the Summary Compensation Table and notes thereto. Such amounts take into account the performance relative to our 2014 goals; areas where performance failed to meet 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 reflected in the Summary Compensation Table for 2014 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 reflected in the Summary Compensation Table for 2014 represented approximately 46% in annual bonus and 54% in quarterly bonus.

Long-Term Incentive Awards. There were no grants of long-term incentive awards to Named Executive Officers in 2014.

Other Compensation Related Matters

Equity Ownership in PAA. Our Named Executive Officers collectively own 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 February 17, 2015, our Named Executive Officers beneficially owned, in the aggregate, (i) approximately 2.2 million of our common units (excluding any unvested equity awards), (ii) through their ownership of interests in PAA Management, L.P., an approximate 2.0% indirect ownership interest (approximate

Table of Contents

1.9% economic interest) in AAP, and (iii) 28,931,571 AAP Management Units, which represent an approximate 4.1% economic interest in AAP. Based on the market price of our common units and PAGP s Class A shares at February 17, 2015 and assuming the conversion of all earned AAP Management Units into AAP units at a conversion factor of approximately 0.930 and the exchange of such AAP units for an equivalent number of PAGP Class A shares, the value of the equity ownership of these individuals was significantly greater than the combined aggregate salaries and bonuses of these individuals for 2014.

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 have reduced the size of such award or payment if previously known.

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

Change in Control Triggers. The employment agreements for Messrs. Armstrong and Pefanis, the long-term incentive plan grants to our Named Executive Officers, and the AAP Management Unit grant agreements to which our Named Executive Officers are a party include severance payment provisions or accelerated vesting triggered upon a change of control, as defined in the respective agreements. In the case of the long-term incentive plan grants, the provision becomes operative only if the change in control is accompanied by a change in status (such as the termination of employment by GP LLC). We believe this double trigger arrangement is appropriate because it provides assurance to the executive, but does not offer a windfall to the executive when there has been no real change in employment status. The provisions in the employment agreements for Messrs. Armstrong and Pefanis become operative only if the executive terminates employment within three months of the change in control. Messrs. Armstrong and Pefanis agreed to a conditional waiver of these provisions with respect to Vulcan Energy Corporation s (Vulcan Energy) sale of its 50.1% general partner interest in December 2010 and with respect to the completion of the initial public offering of PAGP in October 2013. The AAP Management Unit grant 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 AAP Management Units would be forfeited (unless waived at the discretion of the general partner or acquirer as the case may be). As a result of significant participation by existing general partner owners or their affiliates in the December 2010 sale of Vulcan Energy s 50.1% ownership in the general partner, the change of control provisions of the AAP Management Unit grant agreements were not triggered. In addition, the completion of the initial public offering of PAGP in October 2013 did not constitute a change of control pursuant to the terms of the AAP Management Unit grant agreements. See Employment Contracts and Potential Payments upon Termination or Change-in-Control. The provision of severance or equity acceleration for certain terminations and change of control help to create a retention tool by assuring the executive that the benefit of the employment arrangement will be at least partially realized despite the occurrence of an event that would materially alter the employment arrangement.

Relation of Compensation Policies and Practices to Risk Management

Our compensation policies and practices are designed to provide rewards for short-term and long-term performance, both on an individual basis and at the entity level. In general, optimal financial and operational performance, particularly in a competitive business, requires some degree of risk-taking. Accordingly, the use of compensation as an incentive for performance can foster the potential for management and others to take unnecessary or excessive risks to reach the performance thresholds. For us, such risks would primarily attach to certain commercial activities conducted in our supply and logistics segment as well as to the execution of capital expansion projects and acquisitions and the realization of associated returns.

From a risk management perspective, our policy is to conduct our commercial activities within pre-defined risk parameters that are closely monitored and are structured in a manner intended to control and minimize the potential for unwarranted risk-taking. See Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model Risk Management in Part I of this annual report. We also routinely monitor and measure the execution and performance of our capital projects and acquisitions relative to expectations.

Table of Contents

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 Business Conduct. In addition, our long-term incentive awards typically include vesting criteria based on payment of distributions from currently available cash. See Compensation Discussion and Analysis Relation of Compensation Elements to Compensation Objectives.

In combination with our risk-management practices, we do not believe that risks arising from our compensation policies and practices for our employees are reasonably likely to have a material adverse effect on us.

Summary Compensation Table

The following table sets forth certain compensation information for our Chief Executive Officer, Chief Financial Officer, and the three other most highly compensated executive officers in 2014 (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 AAP Management Units).

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)(1)	All Other Compensation ($)(2)	Total ($)
Greg L. Armstrong	2014	375,000	3,900,000		17,040	4,292,040
Chairman and Chief Executive	2013	375,000	4,400,000	2,662,378	16,740	7,454,118
Officer	2012	375,000	5,200,000		16,320	5,591,320
Harry N. Pefanis	2014	300,000	3,800,000		17,040	4,117,040
President and Chief Operating	2013	300,000	4,250,000	2,396,140	16,740	6,962,880
Officer	2012	300,000	5,000,000		16,320	5,316,320
Al Swanson	2014	250,000	1,650,000		17,040	1,917,040
Executive Vice President and	2013	250,000	1,800,000	1,774,919	16,740	3,841,659
Chief Financial Officer	2012	250,000	2,000,000		16,320	2,266,320
W. David Duckett(3)	2014	257,571	3,244,686		101,472	3,603,729
President Plains Midstream	2013	276,666	3,887,652	1,774,919	102,936	6,042,173
Canada	2012	285,380	4,080,876		115,433	4,481,689
John P. vonBerg	2014	250,000	4,175,000(4)		17,040	4,442,040
Executive Vice President	2013	250,000	5,255,000(4)	1,331,189	16,740	6,852,929
Commercial Activities	2012	250,000	6,315,000(4)		16,320	6,581,320

(1) Grant date fair values are presented for LTIP phantom unit grants awarded to Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg in 2013. Dollar amounts in the table represent the aggregate grant date fair value of phantom units awarded based on the probable outcome of underlying performance conditions pursuant to FASB ASC Topic 718. The performance threshold for the first tranche of vesting was deemed probable of occurring on the grant date. The maximum grant date fair values of phantom unit grants awarded in 2013 assuming that the highest level of performance conditions will be met are: $7,562,664 for Mr. Armstrong; $6,806,398 for Mr. Pefanis;

$5,041,776 for Mr. Swanson; $5,041,776 for Mr. Duckett and $3,781,332 for Mr. vonBerg. See Note 16 to our Consolidated Financial Statements for further discussion regarding the calculation of grant date fair values.

Table of Contents

(2) 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 $15,600 in such contributions for 2014. 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 2014, employer contributions to the Plains Midstream Canada savings plan of $33,484, group term life insurance premiums of $31,751, automobile lease payments of $29,571 and club dues of $6,666.

(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 $2,275,000, $3,355,000 and $4,115,000 and annual bonuses of $1,900,000, $1,900,000 and $2,200,000 in 2014, 2013 and 2012, respectively. The annual bonuses are payable 60% at the time of award and 20% in each of the two succeeding years.

Grants of Plan-Based Awards Table

There were no grants of plan-based awards to our Named Executive Officers during the fiscal year ended December 31, 2014.

Narrative Disclosure to Summary Compensation Table

A narrative description of all material factors necessary to an understanding of the information included in the above Summary Compensation Table is included in Compensation Discussion and Analysis and in the footnotes to such tables.

Employment Contracts

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

Mr. Pefanis is employed as President and Chief Operating Officer. The initial three-year term of Mr. Pefanis employment agreement commenced on June 30, 2001, and is automatically extended for one year on June 30 of each year (such that the term is reset to three years) unless Mr. Pefanis receives notice from the Chairman of the Board that the board of directors has elected not to extend the agreement. Mr. Pefanis has agreed, during the term of the agreement and for one year thereafter, not to disclose (subject to typical exceptions) any confidential information obtained by him while employed under the agreement. The agreement provided for a base salary of $235,000 per year, subject to annual review. In 2005, Mr. Pefanis annual salary was increased to $300,000.

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

Table of Contents

Outstanding Equity Awards at Fiscal Year-End

The following table sets forth certain information regarding outstanding equity awards at December 31, 2014 with respect to our Named Executive Officers:

	Unit Awards			
Name	**Number of Shares or Units of Stock That Have Not Vested (#)**	**Market Value of Shares or Units of Stock That Have Not Vested ($)(1)**	**Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(1)**
Greg L. Armstrong	10,425,791(2)	247,683,292		
	120,000(3)	6,158,400		
	100,000(4)	5,132,000	50,000(4)	2,566,000
Harry N. Pefanis	7,819,344(2)	185,762,495		
	80,000(3)	4,105,600		
	90,000(4)	4,618,800	45,000(4)	2,309,400
Al Swanson	2,606,448(2)	61,920,823		
	40,000(3)	2,052,800		
	66,667(4)	3,421,350	33,333(4)	1,710,650
W. David Duckett	4,430,961(2)	105,265,402		
	50,000(3)	2,566,000		
	66,667(4)	3,421,350	33,333(4)	1,710,650
John P. vonBerg	3,649,027(2)	86,689,157		
	36,000(3)	1,847,520		
	50,000(4)	2,566,000	25,000(4)	1,283,000

(1) Market value of phantom units reported in these columns is calculated by multiplying the closing market price ($51.32) of our common units at December 31, 2014 (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. Market value of AAP Management Units is calculated by (i) assuming that such AAP Management Units are converted into AAP units based on the December 31, 2014 conversion factor of approximately 0.925 AAP units and PAGP Class B shares for each AAP Management Unit, (ii) assuming the exchange of the resulting AAP units and PAGP Class B shares for PAGP Class A shares on a one-for-one basis, and (iii) multiplying such resulting number of PAGP Class A shares by the closing market price ($25.68) of PAGP s Class A shares at December 31, 2014 (the last trading day of the fiscal year).

(2) Represents the pre-conversion number of AAP Management Units held by the applicable individual, each of which represents a profits interest in AAP, entitling the holder to participate in future profits and losses from operations, current distributions from operations, and an interest in future appreciation or depreciation in AAP s asset values, but does not represent an interest in the capital of AAP on

the applicable grant date of the AAP Management Units. Despite the fact that 100% of the AAP Management Units held by our Named Executive Officers had been earned as of December 31, 2014 (i.e., all relevant performance benchmarks have been satisfied), all such AAP Management Units are treated as stock that has not vested for purposes of this table due to the fact that, as of December 31, 2014, they remained subject to a call right held by AAP. Such call right gives AAP the right to purchase such AAP Management Units for an amount equal to 75% of the fair market value of such AAP Management Units upon the termination of the applicable Named Executive Officer s employment with GP LLC and its

Table of Contents

affiliates prior to January 1, 2016 (subject to certain exceptions as set forth in the AAP Management Unit grant agreements). If at any time after December 31, 2015 the PAGP Class A shares are publicly traded, each vested AAP Management Unit may be converted into AAP units and a like number of PAGP Class B shares based on a conversion ratio calculated in accordance with the AAP limited partnership agreement (which conversion ratio will not be more than one-to-one and was approximately 0.925 AAP units and PAGP Class B shares for each AAP Management Unit as of December 31, 2014). Following any such conversion, the resulting AAP units and PAGP Class B shares are exchangeable for PAGP Class A shares on a one-for-one basis as provided in the PAGP limited partnership agreement. For additional information regarding the AAP Management Units, please read Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner AAP Management Units.

(3) Represents phantom units granted in 2010 under our Long-Term Incentive Plan. As of December 31, 2014, all of these phantom units had been earned and will vest on the May 2015 distribution date. All of the DERs associated with these phantom units are currently payable.

(4) Represents phantom units granted in 2013 under our Long-Term Incentive Plan. These phantom units will vest as follows: (i) one-third will vest on the August 2016 distribution date as the quarterly distribution threshold of $0.5875 ($2.35 annualized) has already been satisfied, (ii) one third will vest on the August 2017 distribution date as the quarterly distribution threshold of $0.6250 ($2.50 annualized) has already been satisfied, and (iii) one-third will vest on the August 2018 distribution date as the quarterly distribution threshold of $0.6625 ($2.65 annualized) will have been satisfied as of the February 2015 distribution date. Upon vesting, the phantom units are payable on a one-for-one basis in PAA common units. All of the DERs associated with these phantom units are currently payable. The DERs expire when the associated phantom units vest. Any of these phantom units (and all associated DERs) that have not vested as of the August 2019 distribution date will be forfeited.

Option Exercises and Units Vested

The following table sets forth certain information regarding the vesting of phantom units during the fiscal year ended December 31, 2014 with respect to our Named Executive Officers.

	Unit Awards	
Name	**Number of Units Acquired on Vesting (#)**	**Value Realized on Vesting ($)**
Greg L. Armstrong	120,000(1)	6,831,600(2)
Harry N. Pefanis	80,000(1)	4,554,400(2)
Al Swanson	40,000(1)	2,277,200(2)
W. David Duckett	50,000(1)	2,846,500(2)
John P. vonBerg	36,000(1)	2,049,480(2)

(1) Represents the gross number of phantom units that vested during the year ended December 31, 2014. The actual number of units delivered was net of income tax withholding.

(2) Consistent with the terms of our Long-Term Incentive Plan, the value realized upon vesting is computed by multiplying the closing market price ($56.93) of our common units on May 14, 2014 (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, 2014.

	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	11,150,000(1)	11,150,000(1)	11,150,000(1)	11,150,000(1)	16,725,000(2)
Equity Compensation	11,290,400(3)	11,290,400(3)	13,856,400(4)	13,856,400(4)	13,856,400(5)
Health Benefits	N/A	30,624(6)	30,624(6)	30,624(6)	30,624(6)
Tax Gross-up	N/A	N/A	N/A	N/A	987,337(7)
AAP Management Units	N/A	N/A	61,920,823(8)	61,920,823(8)	61,920,823(9)
Total	22,440,400	22,471,024	86,957,847	86,957,847	93,520,184
Harry N. Pefanis					
Salary and Bonus	10,600,000(1)	10,600,000(1)	10,600,000(1)	10,600,000(1)	15,900,000(2)
Equity Compensation	8,724,400(3)	8,724,400(3)	11,033,800(4)	11,033,800(4)	11,033,800(5)
Health Benefits	N/A	47,620(6)	47,620(6)	47,620(6)	47,620(6)
Tax Gross-up	N/A	N/A	N/A	N/A	1,370,724(7)
AAP Management Units	N/A	N/A	46,440,624(8)	46,440,624(8)	46,440,624(9)
Total	19,324,400	19,372,020	68,122,044	68,122,044	74,792,768
Al Swanson (10)					
Equity Compensation	5,474,150(3)	5,474,150(3)	5,474,150(4)	N/A	7,184,800(5)
AAP Management Units	N/A	N/A	15,480,206(8)	15,480,206(8)	15,480,206(9)
Total	5,474,150	5,474,150	20,954,356	15,480,206	22,665,006
W. David Duckett (10)					
Equity Compensation	5,987,350(3)	5,987,350(3)	5,987,350(4)	N/A	7,698,000(5)

AAP Management Units	N/A	N/A	26,316,350(8)	26,316,350(8)	26,316,350(9)
Total	5,987,350	5,987,350	32,303,700	26,316,350	34,014,350
John P. vonBerg (10)					
Equity Compensation	4,413,520(3)	4,413,520(3)	4,413,520(4)	N/A	5,696,520(5)
AAP Management Units	N/A	N/A	21,672,289(8)	21,672,289(8)	21,672,289(9)
Total	4,413,520	4,413,520	26,085,809	21,672,289	27,368,809

(1) The employment agreements between GP LLC and Messrs. Armstrong and Pefanis provide that if (i) their employment with GP LLC is terminated as a result of their death, (ii) they terminate their employment with 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) 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, 2014, and also assumes a highest annual base salary of $375,000 and highest annual bonus of $5,200,000 for Mr. Armstrong, and a highest annual base salary of $300,000 and highest annual bonus of $5,000,000 for Mr. Pefanis.

The employment agreements between 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 GP LLC or otherwise likely to result in no material injury to GP LLC. However, neither Mr. Armstrong nor 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 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, 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 GP LLC and Messrs. Armstrong and Pefanis define good reason as the occurrence of any of the following circumstances: (i) removal by 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 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 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 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 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, 2014, and also assumes a highest annual base salary of $375,000 and highest annual bonus of $5,200,000 for Mr. Armstrong, and a highest annual base salary of $300,000 and highest annual bonus of $5,000,000 for Mr. Pefanis.

Change in control was originally 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 GP LLC or (ii) the owners of the membership interests of GP LLC on June 30, 2001 ceasing to beneficially own, directly or indirectly, more than 50% of the membership interests of GP LLC.

In August 2005, Vulcan Energy increased its interest in GP LLC from approximately 44% to greater than 50%. The consummation of the transaction constituted a change in control under the employment agreements with Messrs. Armstrong and Pefanis. However, Messrs. Armstrong and Pefanis entered into agreements with GP LLC waiving their rights to payments under their employment agreements in connection with the change in control, contingent on the execution and performance by Vulcan Energy of a voting agreement with GP LLC that restricted certain of Vulcan s voting rights. The December 2010 sale by Vulcan Energy of its interest in our general partner also constituted a change in control under the employment agreements and resulted in the termination of the voting agreement. Messrs. Armstrong and

Table of Contents

Pefanis executed new agreements waiving their rights to payments under their employment agreements with respect to the December 2010 transaction and voting agreement termination.

The initial public offering of PAGP and certain related transactions also would have constituted a change in control under the employment agreements, which would have allowed Messrs. Armstrong and Pefanis to terminate their employment and become entitled to certain separation benefits. Messrs. Armstrong and Pefanis executed agreements waiving their rights to terminate employment and receive such benefits. In connection with such waiver, the definition of Change in Control in the employment agreements was also modified to mean, and will be deemed to occur upon, one or more of the following events: (i) any person (other than PAGP or its wholly owned subsidiaries), 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, becomes the beneficial owner, directly or indirectly, of 50% or more of the membership interest in GP LLC or 50% or more of the outstanding limited partnership interests of PAGP; (ii) any person (other than PAGP or its wholly owned subsidiaries), 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, becomes the beneficial owner, directly or indirectly, of 50% or more of the membership interest in PAA GP Holdings LLC; (iii) PAGP ceases to beneficially own, directly or indirectly, more than 50% of the membership interest in GP LLC; (iv) KAFU Holdings, L.P. and its affiliates, Lynx Holdings I, LLC and its affiliates, Oxy Holding Company (Pipeline), Inc. and its affiliates, Mark Strome and his affiliates, Windy, LLC and its affiliates, PAA Management, L.P. and its affiliates, PAGP and its affiliates, and various individual investors (collectively, the Owner Affiliates), cease to beneficially own, directly or indirectly, more than 50% of the membership interest in PAGP GP; or (v) there has been a direct or indirect 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 PAGP or Plains All American Pipeline, L.P. to one or more persons who are not affiliates of PAGP (third party or parties), other than a transaction in which the Owner Affiliates continue to beneficially own, directly or indirectly, more than 50% of the issued and outstanding voting securities of such third party or parties immediately following such transaction.

(3) The letters evidencing phantom unit grants to our Named Executive Officers in 2010 and 2013 provide that in the event of their death or disability (as defined below), all of their then outstanding phantom units and associated DERs will be deemed nonforfeitable, and (i) any unvested phantom units that had satisfied all of the vesting criteria as of the date of their termination but for the passage of time would vest on the next following distribution date and (ii) the remaining unvested outstanding phantom units will vest on the distribution date on which the vesting criteria is met. For this purpose disability means a physical or mental infirmity that impairs the ability substantially to perform duties for a period of eighteen (18) months or that the general partner otherwise determines constitutes a disability.

Assuming death or disability occurred on December 31, 2014, all of the 2010 phantom unit grants and associated DERs and two-thirds of the 2013 phantom unit grants and associated DERs of our Named Executive Officers would have become nonforfeitable effective as of December 31, 2014, and would vest on the February 2015 distribution date. For the 2013 grants, any units not vested by August 2019 would expire. That portion of the dollar value given that is attributable to PAA phantom units is based on the market value of PAA s common units on December 31, 2014 ($51.32 per unit) without discount for service period.

(4) Pursuant to the phantom unit grants to our Named Executive Officers in 2010 and 2013, in the event their employment is terminated other than in connection with a change of control (as defined in footnote 5 below) or by reason of death, disability (as defined in footnote 3 above) or retirement, all of the phantom units and associated DERs (regardless of vesting) then outstanding under such phantom unit grants would automatically be forfeited as of the date of termination; provided, however, that if GP LLC terminated their employment other than for cause (as defined in footnote 5 below), any unvested phantom units that had satisfied all of the vesting criteria as of the date of their termination but for the passage of time would be deemed nonforfeitable and would vest on the next following distribution date. The dollar value amount provided assumes that our Named Executive Officers were terminated without cause on December 31, 2014. As a result, all of the 2010 phantom unit grants and two-thirds of the 2013 phantom unit grants held

Table of Contents

by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg would be deemed nonforfeitable and would vest on the February 2015 distribution date. That portion of the dollar value given that is attributable to PAA phantom units is based on the market value of PAA s common units on December 31, 2014 ($51.32 per unit), without discount for service period. In addition to the foregoing, under Canadian law, Mr. Duckett could have a claim for additional payment if inadequate notice were given for a termination without cause.

Under the waiver signed in 2010 by Mr. Armstrong and Mr. Pefanis (see footnote 2 above), upon a termination of employment by GP LLC 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 2005 Long-Term Incentive Plan would immediately vest.

(5) The letters evidencing the phantom unit grants to our Named Executive Officers in 2010 and 2013 provide that in the event of a change in status (as defined below), all of the then outstanding phantom units and associated DERs will be deemed nonforfeitable, and such phantom units will vest in full (i.e., the phantom units will become payable in the form of one common unit per phantom unit) upon the next following distribution date. Assuming the change in status occurred on December 31, 2014, all outstanding phantom units and the associated DERs would have become nonforfeitable as of December 31, 2014, and such phantom units would vest on the February 2015 distribution date. That portion of the dollar value given that is attributable to PAA phantom units is based on the market value of PAA s common units on December 31, 2014 ($51.32 per unit), without discount for service period.

The phrase change in status means, with respect to a Named Executive Officer, the occurrence, during the period beginning two and a half months prior to and ending one year following a change of control (as defined below), of any of the following: (A) the termination of employment by 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 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) 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 GP LLC to any person and/or its affiliates, other than to us or 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 GP LLC and (B) us, GP LLC or both; (iv) the persons who own membership interests in GP LLC as of the grant date ceasing to beneficially own, directly or indirectly, more than 50% of the membership interests of 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 GP LLC. Notwithstanding the definition of change of control, no change of control is deemed to have occurred in connection with a restructuring or reorganization related to the securitization and sale to the public of direct or indirect equity interests in the general partner if (x) GP LLC retains direct or indirect control over the general partner and (y) the current members of GP LLC continue to own more than 50% of the member interest in GP LLC. The initial public offering of PAGP did not constitute a change of control under the phantom unit grant letters. The term cause means (i) the failure to perform the duties and responsibilities of a position at an acceptable level as reasonably determined in good faith by the CEO of GP LLC (or by the board in the case of the CEO), or (ii) the violation of 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 GP LLC, if Messrs. Armstrong or Pefanis are terminated other than (i) for cause (as defined in footnote 1 above), (ii) by reason of death or (iii) by resignation (unless such resignation is due to a disability or for good reason (each as defined in footnote 1 above)), then they are entitled to continue to participate, for a period which is the lesser of two years from the date of

termination or the remaining term of the employment agreement, in such health and accident plans or arrangements as are made available by GP LLC to its executive officers generally. The amounts provided in the table assume a termination date of December 31, 2014.

(7) Pursuant to their employment agreements, Messrs. Armstrong and Pefanis will be reimbursed for any excise tax due under Section 4999 of the Code as a result of compensation (parachute) payments made under their respective employment agreements. The values provided for this benefit assume that Messrs. Armstrong and Pefanis were terminated in connection with a change in control effective as of December 31, 2014.

(8) Pursuant to the AAP Management Unit grant agreements of each of our Named Executive Officers, to encourage retention following the achievement of applicable performance benchmarks, AAP retained a call right to purchase any earned AAP Management Units for an amount equal to 75% of fair market value (which is referred to in the AAP Management Unit grant agreements as the Call Value as defined below) of such AAP Management Units, which call right is exercisable upon the termination of such Named Executive Officer s employment with GP LLC and its affiliates prior to January 1, 2016; provided, however, that such call right is not applicable in the case of the termination of such Named Executive Officer s employment without cause (defined below) or in the event of a resignation by such Named Executive Officer with good reason (defined below). In either such event, or if such Named Executive Officer remains employed past December 31, 2015, any earned AAP Management Units are no longer subject to the call right and are deemed to have vested. As of December 31, 2014, 100% of the AAP Management Units held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg had been earned, but all of such AAP Management Units remained subject to AAP s call right. Assuming a termination of employment without cause or for good reason on December 31, 2014, all of the AAP Management Units held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg would become vested and would no longer be subject to the call right. Because the call right provides for a discounted purchase price equal to 75% of fair market value, in such event the applicable Named Executive Officer would benefit by virtue of the fact that such officer s AAP Management Units could no longer be purchased by AAP at a 25% discount. The value reflected in the table above represents the implied value of such benefit to the applicable Named Executive Officer, calculated as of December 31, 2014 by (i) assuming that such officer s AAP Management Units are converted into AAP units based on the December 31, 2014 conversion factor of approximately 0.925 AAP units and PAGP Class B shares for each AAP Management Unit, (ii) assuming the exchange of the resulting AAP units and PAGP Class B shares for PAGP Class A shares on a one-for-one basis, and (iii) multiplying such resulting number of PAGP Class A shares by an amount equal to 25% of the closing market price ($25.68) of PAGP s Class A shares at December 31, 2014 (the last trading day of the fiscal year). The entire economic burden of the AAP Management Units is borne solely by AAP.

Cause is defined in the AAP Management Unit grant agreements as (i) a finding by the board of GP LLC that the executive has substantially failed to perform the duties and responsibilities of his position at an acceptable level and after written notice specifying such failure in detail and after a reasonable period under the circumstances (determined by the board in good faith) such failure has continued without full correction by the executive, (ii) the executive s conviction of or guilty plea to the committing of an act or acts constituting a felony under the laws of the United States or any state thereof or any misdemeanor involving moral turpitude, or (iii) any action by the executive involving personal dishonesty, theft or fraud in connection with executive s duties as an employee of GP LLC or its affiliates.

Good Reason is defined in the AAP Management Unit grant agreements as (i) any material breach by AAP of executive s AAP Management Unit grant agreement, (ii) the failure of any successor of AAP to assume executive s AAP Management Unit grant agreement, or (iii) any material overall reduction the executive s authority, responsibilities or duties.

Call Value is defined in the AAP Management Unit grant agreements as the product of the applicable conversion factor and the closing sales price of the PAGP Class A shares on the applicable date.

(9) Pursuant to the AAP Management Unit grant agreements, upon the occurrence of a Change in Control, any earned AAP Management Units (and any AAP Management Units that will become earned in less than 180 days) become vested units and, to the extent any AAP Management Units remain unearned, an incremental 25% of the number of AAP Management Units originally granted becomes vested. As of December 31, 2014, 100% of the AAP Management Units held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg had been earned. Accordingly, assuming a Change in Control on December 31, 2014, all of the AAP Management Units held by Messrs. Armstrong, Pefanis, Swanson, Duckett and vonBerg would become vested and would no longer be subject to the call right. Because the call right provides for a discounted purchase price equal to 75% of fair market value as described above, the applicable Named Executive Officer would benefit from a Change in Control by virtue of the fact that such officer s AAP Management Units could no longer be purchased by AAP at a 25% discount. The value reflected in the table above represents the implied value of such benefit to the applicable Named Executive Officer, calculated as of December 31, 2014 by (i) assuming that such officer s AAP Management Units are converted into AAP units based on the December 31, 2014 conversion factor of approximately 0.925 AAP units and PAGP Class B shares for each AAP Management Unit, (ii) assuming the exchange of the resulting AAP units and PAGP Class B shares for PAGP Class A shares on a one-for-one basis, and (iii) multiplying such resulting number of PAGP Class A shares by an amount equal to 25% of the closing market price ($25.68) of PAGP s Class A shares at December 31, 2014 (the last trading day of the fiscal year). The entire economic burden of the AAP Management Units is borne solely by AAP.

Change in Control means the determination by the board that one of the following events has occurred: (i) the Persons who own member interests in PAA GP Holdings LLC immediately following the closing of the GP IPO, including PAGP, and the respective Affiliates of such Persons (such owners and Affiliates being referred to as the Owner Affiliates), cease to own directly or indirectly at least 50% of the membership interests of such entity; (ii) (x) a person or group other than the Owner Affiliates becomes the beneficial owner directly or indirectly of 25% or more of the member interest in the general partner of PAGP, and (y) the member interest beneficially owned by such person or group exceeds the aggregate member interest in the general partner of PAGP beneficially owned, directly or indirectly, by the Owner Affiliates; or (iii) a direct or indirect transfer, sale, exchange or other disposition in a single transaction or series of transaction (whether by merger or otherwise) of all or substantially all of the assets of PAGP or PAA to one or more Persons who are not Affiliates of PAGP (third party or parties), other than a transaction in which the Owner Affiliates continues to beneficially own, directly or indirectly, more than 50% of the issued and outstanding voting securities of such third party or parties immediately following such transaction.

(10) If Messrs. Swanson, Duckett or vonBerg were terminated for cause, 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.

Table of Contents

Compensation of Directors

The following table sets forth a summary of the compensation paid to each person who served as a non-employee director of GP LLC in 2014:

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)(1)	Total ($)
Everardo Goyanes	75,000	290,100	365,100
Gary R. Petersen	45,000	145,050	190,050
John T. Raymond	45,000	145,050	190,050
Robert V. Sinnott	47,000	145,050	192,050
Vicky Sutil (2)	45,000	n/a	45,000
J. Taft Symonds	62,000	290,100	352,100
Christopher M. Temple	60,000	290,100	350,100

(1) The dollar value of LTIPs granted during 2014 is based on the grant date fair value computed in accordance with FASB ASC Topic 718. See Note 16 to our Consolidated Financial Statements for additional discussion regarding the calculation of grant date fair values. In connection with the August 2014 vesting of director LTIP awards, Messrs. Goyanes, Symonds and Temple each were granted 5,000 units, and Messrs. Petersen, Raymond and Sinnott each were granted 2,500 units by virtue of the automatic re-grant feature of the vested awards. Upon vesting of the director LTIP awards in August 2014 (other than the incremental audit committee awards), a cash payment of $132,850 was made to Oxy as directed by Ms. Sutil. Such cash payment was based on the unit value of Mr. Sinnott s award on the previous year s vesting date. As of December 31, 2014, the number of outstanding LTIPs held by our directors was as follows: Goyanes - 20,000; Petersen - 10,000; Raymond - 10,000; Sinnott - 10,000; Symonds - 20,000; and Temple - 20,000.

(2) Ms. Sutil s compensation was assigned to Oxy. Ms. Sutil departed the board in January 2015.

Each director of GP LLC who is not an employee of 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; however, the annual retainer fee for the director designated by Oxy is paid to Oxy. 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 2014, Messrs. Sinnott, Goyanes and Symonds served as chairmen of the compensation, audit and governance committees, respectively.

Our non-employee directors receive LTIP awards or cash equivalent awards as part of their compensation. The LTIP awards vest annually in 25% increments over a four-year period and have an automatic re-grant feature such that as they vest, an equivalent amount is granted. The awards have associated distribution equivalent rights that are payable quarterly. The three non-employee directors who serve on the audit committee (Messrs. Goyanes, Symonds and Temple) each have outstanding a grant of 20,000 units (vesting 5,000 units per year). Messrs. Petersen, Raymond and Sinnott each have outstanding a grant of 10,000 units (vesting 2,500 units per year). Upon vesting of the director LTIPs (other than the incremental audit committee awards), a cash payment will be made to Oxy as directed by the Oxy designee. Such cash payment is based on the unit value of Mr. Sinnott s award on the previous year s vesting date.

All LTIP awards held by a director vest in full upon the next following distribution date after the death or disability (as determined in good faith by the board) of the director. For audit committee grants, the awards also vest in full if such director (i) retires (no longer with full-time employment and no longer serving as an officer or director

Table of Contents

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.

Messrs. Figlock, Goyanes, Raymond and Sinnott also serve as directors of GP Holdings, and Mr. Goyanes also serves as chairman of the GP Holdings audit committee. Messrs. Figlock, Raymond and Sinnott do not receive additional compensation for their service on the GP Holdings board. Mr. Goyanes does not receive additional cash compensation for his service as a director and chairman of the audit committee of the GP Holdings board, but he received initial equity compensation in the form of an LTIP award for 19,200 phantom Class A shares of PAGP that, subject to continued service as a GP Holdings director, vests in 25% increments over a four-year period and includes an automatic re-grant equal to 25% of the initial award. Mr. Goyanes LTIP award has associated distribution equivalent rights that are payable quarterly and entitle Mr. Goyanes to receive a cash payment for each phantom Class A share equal in amount to the distribution paid by PAGP on its Class A shares.

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 AAP Management Units) 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 17, 2015.

Name of Beneficial Owner	Common Units	Percentage of Common Units
Tortoise Capital Advisors, L.L.C.(1) 11550 Ash Street, Suite 300 Leawood, Kansas 66211	24,086,246	6.4%
Richard Kayne/Kayne Anderson Capital Advisors, L.P.	12,890,512(2)	3.4%
Greg L. Armstrong	1,197,690(3)	*
Harry N. Pefanis	771,381(3)	*
W. David Duckett	(3)	
John P. vonBerg	122,359(3)	*
Al Swanson	123,429(3)	*
Ben Figlock		
Everardo Goyanes	78,400(3)	*
Gary R. Petersen	34,450(3)	*
John T. Raymond	1,426,933(3)	*
Robert V. Sinnott	341,393(3)(4)	*
J. Taft Symonds	94,050(3)	*
Christopher M. Temple	21,250(3)	*
All directors and executive officers as a group (17 persons)	4,836,772(3)(5)	1.3%

* Less than 1%.

(1) This information has been derived from a Schedule 13G filed with the SEC on February 10, 2015.

(2) 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 12,290,598 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 599,914 common units. Mr. Kayne disclaims beneficial ownership of any of our partner interests other than units held by him or interests attributable to him by virtue of his interests in the accounts that own our partner interests. The address for Mr. Kayne and Kayne Anderson Investment Management, Inc. is 1800 Avenue of the Stars, 3rd Floor, Los Angeles, California 90067.

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

(4) Pursuant to the GP LLC Agreement, Mr. Sinnott is one of our directors by virtue of his designation as a member of the board of directors of GP Holdings by KAFU Holdings, L.P., which is controlled by Kayne Anderson Investment Management, Inc., of which he is President. Mr. Sinnott disclaims any deemed beneficial ownership of the interests owned by KAFU Holdings, L.P. or its affiliates, beyond his pecuniary interest therein, if any. Mr. Sinnott has a non-controlling ownership interest in KACALP, which is the general partner of KAFU Holdings, L.P. KACALP is entitled to a percentage of the profits earned by the funds invested in KAFU Holdings, L.P. The address for KAFU Holdings, L.P. is 1800 Avenue of the Stars, 3rd Floor, Los Angeles, California 90067.

(5) As of February 17, 2015, 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 17, 2015.

Table of Contents

Beneficial Ownership of General Partner Interest

AAP owns all of our incentive distribution rights and, through its 100% member interest in PAA GP LLC, our 2% general partner interest. GP LLC owns a non-economic general partner interest in AAP. Thus, GP LLC has responsibility for conducting our business and managing our operations and the Class A limited partners of AAP, together with the holders of the AAP Management Units, collectively own 100% of the economic interests in AAP. The following table sets forth the percentage ownership of each of the Class A limited partners of AAP and the resulting economic interest of each such limited partner and the holders of the AAP Management Units as a group, in each case as of February 17, 2015:

Name of Owner and Address (in the case of Owners of more than 5%)	Percentage Ownership of Plains AAP, L.P. Class A LP Interest	Economic Interest in Plains AAP, L.P. (1)
Plains GP Holdings, L.P. 333 Clay Street, Suite 1600 Houston, TX 77002	34.81%	32.37%
EMG Investment, LLC 811 Main, Suite 4200 Houston, TX 77002	20.05%	18.64%
KAFU Holdings, L.P. and Affiliates 1800 Avenue of the Stars, 3rd Floor Los Angeles, CA 90067	18.23%	16.95%
KA First Reserve XII, LLC	1.82%	1.70%
Oxy Holding Company (Pipeline), Inc. 5 Greenway Plaza Houston, TX 77046	13.17%	12.25%
PAA Management, L.P. (2)	3.60%	3.35%
Strome PAA, L.P. and Affiliate	3.38%	3.14%
Windy, L.L.C.	3.00%	2.79%
Lynx Holdings I, LLC	1.40%	1.30%
Various Individual Investors	0.54%	0.50%
AAP Management Unitholders(3)		7.01%

(1) AAP owns a 100% member interest in PAA GP LLC, which owns our 2% general partner interest. AAP has pledged its member interest, as well as its interest in our incentive distribution rights, as security for its obligations under the Second Amended and Restated Credit Agreement dated as of September 26, 2013 among AAP, Citibank, N.A. and the lenders party thereto (the Plains AAP Credit Agreement). A default by AAP under the Plains AAP Credit Agreement could result in a change in control of our general partner.

(2) PAA Management, L.P. is owned entirely by certain current and former members of senior management, including Messrs. Armstrong (approximately 25%), Pefanis (approximately 14%), Duckett (approximately 6%), vonBerg (approximately 4%) and Swanson (approximately 5%). Other than Mr. Armstrong, none of our directors own any interest in PAA Management, L.P. Executive officers as a group own approximately 65% of PAA Management, L.P. Mr. Armstrong disclaims any beneficial ownership of the general partner interest owned by AAP, except to the extent of his ownership interest in PAA Management, L.P.

(3) Represents profits interest in AAP in the form of AAP Management Units owned by certain members of management. Named Executive Officers and executive officers as a group own the following AAP Management Units: Mr. Armstrong 10,425,791; Mr. Pefanis 7,819,344; Mr. Swanson 2,606,448; Mr. Duckett 4,430,961; Mr. vonBerg 3,649,027, and executive officers as a group 37,793,493. None of our directors own any AAP Management Units.

Table of Contents

Equity Compensation Plan Information

The following table sets forth certain information with respect to our equity compensation plans as of December 31, 2014. 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:			
2013 Long Term Incentive Plan	3,299,354(1)	N/A(2)	9,294,381(1)(3)
Equity compensation plans not approved by unitholders:			
PNG Successor LTIP	224,690(4)	N/A(2)	977,461(3)(4)

(1) The 2013 Long-Term Incentive Plan (the 2013 Plan), which was approved by our unitholders in November 2013, consolidated three prior plans (the Plains All American GP LLC 1998 Long-Term Incentive Plan (the 1998 Plan), the Plains All American GP LLC 2005 Long-Term Incentive Plan (the 2005 Plan), and the PPX Successor Long-Term Incentive Plan (the PPX Successor Plan)). The 2013 Plan contemplates the issuance or delivery of up to 13,074,686 common units to satisfy awards under the plan, which amount is net of 4,774,932 common units previously issued under the prior plans. The number of units presented in column (a) assumes that all remaining grants will be satisfied by the issuance of new units upon vesting unless such grants are by their terms payable only in cash. In fact, a substantial number of phantom units that have vested were satisfied without the issuance of units. These phantom units were settled in cash or withheld for taxes. Any units not issued upon vesting will become available for future issuance under column (c).

(2) Phantom unit awards under the 2013 Plan and PNG Successor Plan 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) In December 2013, in connection with the PNG Merger, we adopted and assumed the PAA Natural Gas Storage, L.P. 2010 Long Term Incentive Plan (the PNG Legacy Plan), and all outstanding awards of PNG phantom units were converted into comparable awards of PAA phantom units by applying the merger exchange ratio of 0.445 PAA common units for each PNG common unit and rounding down for any fractions. The GP LLC board of directors amended and restated the PNG Legacy Plan, which is now known as the PNG Successor Long-Term Incentive Plan (the PNG Successor Plan). The PNG Successor Plan contemplates the issuance or delivery of up to 1,319,983 units to satisfy awards under the plan, which amount is net of 15,017 common units previously issued under the PNG Legacy Plan. The number of units presented in column (a) assumes that all outstanding grants will be satisfied by the issuance of new units upon vesting unless such LTIPs are by

their terms payable only in cash. In fact, some portion of the phantom units may be settled in cash and some portion will be withheld for taxes. Any units not issued upon vesting will become available for future issuance under column (c).

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, Plains Midstream Canada). We do not pay our general partner a management fee, but we do reimburse our general partner for all expenses incurred on our behalf (other than expenses related to the AAP Management Units). Total costs reimbursed by us to our general partner for the year ended December 31, 2014 were approximately $598 million.

Our general partner owns the 2% general partner interest and all of the incentive distribution rights. 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 distribution provisions, generally our general partner is entitled, without duplication and except for the agreed upon adjustments discussed below, to 2% of amounts we distribute up to $0.2250 ($0.90 annualized) per unit, 15% of amounts we distribute in excess of $0.2250 ($0.90 annualized) per unit, 25% of the amounts we distribute in excess of $0.2475 ($0.99 annualized) per unit and 50% of amounts we distribute in excess of $0.3375 ($1.35 annualized) per unit. Our general partner s incentive distributions were reduced by approximately $11 million, $15 million and $23 million in 2012, 2013 and 2014, respectively. These reductions were agreed to in connection with the BP NGL Acquisition and the PNG Merger. In addition, our general partner has agreed to reduce the amount of its incentive distributions by $5.5 million per quarter during 2015, $5 million per quarter in 2016 and $3.75 million per quarter thereafter.

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

Annual LP Distribution Per Unit	Distribution to LP Unitholders(1)	Distribution to GP(1)(2)	Total Distribution(1)(2)	GP % of Total Distribution
$ 0.90	$ 337,500	$ 6,888	$ 344,388	2.0%
$ 0.99	$ 371,250	$ 12,844	$ 384,094	3.3%
$ 1.35	$ 506,250	$ 57,844	$ 564,094	10.3%
$ 2.65	$ 993,750	$ 545,344	$ 1,539,094	35.4%
$ 2.85	$ 1,068,750	$ 620,344	$ 1,689,094	36.7%
$ 3.00	$ 1,125,000	$ 676,594	$ 1,801,594	37.6%
$ 3.10	$ 1,162,500	$ 714,094	$ 1,876,594	38.1%

(1) Assumes 375,000,000 units outstanding. The actual number of units outstanding as of December 31, 2014 was 375,107,793. An increase in the number of units outstanding would increase both the distribution to unitholders and the distribution to the general partner for any given level of distribution per unit.

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

Equity-Based Long-Term Incentive Plans

In November 2013, our unitholders approved the adoption of the 2013 Plan, which consolidated three prior plans (the 1998 LTIP, the 2005 LTIP, and the PPX Successor Plan). In December 2013, in connection with the PNG Merger, we adopted and assumed the PNG Legacy Plan, and all outstanding awards of PNG phantom units were converted into comparable awards of PAA phantom units by applying the merger exchange ratio of 0.445 PAA common units for each PNG common unit and rounding down for any fractions. The GP LLC board of directors amended and restated the PNG Legacy Plan, which is now known as the PNG Successor Plan (together with the 2013 Plan, the Plans). The provisions of the PNG Successor Plan are substantially the same as the 2013 Plan, except that new awards under the PNG Successor Plan may only be made to employees hired after the date of the PNG Merger. Awards contemplated by the Plans include phantom units, distribution equivalent rights (DERs), unit

Table of Contents

appreciation rights, restricted units, and unit options. The 2013 Plan authorizes the grant of awards covering an aggregate of 13,074,686 common units deliverable upon vesting or exercise (as applicable) of such awards. The PNG Successor Plan authorizes the grant of awards covering an aggregate of 1,319,983 common units deliverable upon vesting or exercise (as applicable) of such awards. Our general partner s board of directors has the right to alter or amend the Plans from time to time, including, subject to any applicable NYSE listing requirements, increasing the number of common units with respect to which awards may be granted; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of such participant.

Common units to be delivered upon the vesting of rights may be common units acquired in the open market or, common units acquired from us, any of our affiliates or any other person, 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 Plans 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). 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.

As of December 31, 2014, grants of approximately 4,097,655 and 269,645 unvested phantom units were outstanding under the 2013 Plan and PNG Successor Plan, respectively, and approximately 9,294,381 and 977,461 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.

Unit Appreciation Rights. A unit appreciation right is an award that, upon exercise, entitles the holder to receive the excess, if any, of the fair market value of a common unit on the exercise date over the grant price of the unit appreciation right. The excess may be paid in cash and/or common units as determined by the plan administrator in its discretion. No unit appreciation rights have been granted under the Plans to date.

Restricted Unit Awards. A restricted unit is a common unit granted under the Plan that is subject to a risk of forfeiture, restrictions on transferability, and any other restrictions that may be imposed by the plan administrator in its discretion. No restricted unit awards have been granted under the Plans to date.

Unit Options. Options may be granted under the Plan to purchase a specific number of common units at a set exercise price. The exercise price of each option granted under the Plan will be determined by the plan administrator at the time the option is granted, provided that each option may not have an exercise price that is less than the fair market value of the common units on the date of grant. No options have been granted under the Plans to date.

AAP Management Units

In August 2007, the owners of AAP authorized the creation and issuance of AAP Management Units and authorized the compensation committee of GP LLC to issue grants of AAP Management Units to create long-term incentives for our management. The entire economic burden of the AAP Management Units, which are equity classified, is borne solely by AAP and does not impact our cash or units outstanding. We are not obligated to reimburse AAP for any costs attributable to the AAP Management Units, and any distributions made on the AAP Management Units will not reduce the amount of cash available for distribution to our unitholders. Each AAP Management Unit represents a profits interest in AAP, 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 AAP s asset values. Up to 52,125,935 AAP Management Units are authorized for issuance. As of December 31, 2014, 49,172,830 AAP Management Units were issued and outstanding.

The outstanding AAP Management Units are subject to restrictions on transfer and generally become earned (entitled to receive a portion of the distributions that would otherwise be paid to holders of AAP units) in percentage increments when the annualized quarterly distributions on our common units equal or exceed certain thresholds. Upon achievement of these performance thresholds (or, in some cases, within six months thereafter), the AAP Management Units will be entitled to their proportionate share of all quarterly cash distributions made by AAP in excess of $11 million per quarter (as adjusted for debt service costs and excluding special distributions funded by debt). Assuming all authorized AAP Management Units are issued, the maximum participation would be approximately 8% of the amount in excess of $11 million per quarter, as adjusted. As of February 17, 2015, approximately 98% of the outstanding AAP Management Units had been earned or will be earned within 180 days. The remaining AAP Management Units will be earned in 25% increments 180 days after payment of annualized quarterly distributions of $2.85, $3.00 and $3.10 per unit, respectively.

To encourage retention following achievement of these performance benchmarks, AAP retained a call right to purchase any earned AAP Management Units at a discount to fair market value that is exercisable upon the termination of a holder s employment with GP LLC and its affiliates (other than a termination without cause or by the employee for good reason) prior to certain stated dates. If a holder of an AAP Management Unit remains employed past such designated date (or prior to such date is terminated without cause or quits for good reason), any earned units are no longer subject to the call right and are deemed to have vested. The applicable designated dates for the various AAP Management Unit grants range from January 1, 2016 for AAP Management Units granted in 2007 to January 1, 2022 for AAP Management Units granted in 2014. If the call right of AAP becomes exercisable, in order to encourage retention, the size of the discount to fair market value reflected in the purchase price decreases over time pursuant to a formula set forth in each AAP Management Unit grant agreement. AAP Management Unit grants also provide that all earned AAP Management Units and a portion of any unearned and unvested AAP Management Units will vest upon a change of control. All earned AAP Management Units will also vest if AAP does not timely exercise its call right.

If at any time after December 31, 2015 the PAGP Class A shares are publicly traded, each vested AAP Management Unit may be converted into AAP units and a like number of PAGP Class B shares based on a conversion ratio calculated in accordance with the AAP limited partnership agreement (which conversion ratio will not be more than one-to-one and was approximately 0.930 AAP units and PAGP Class B shares for each AAP Management Unit as of February 17, 2015). Following any such conversion, the resulting AAP units and PAGP Class B shares are exchangeable for PAGP Class A shares on a one-for-one basis as provided in the PAGP limited partnership agreement.

Administrative Agreement

In connection with the closing of the initial public offering of PAGP, PAA entered into an administrative agreement (the Administrative Agreement) with PAGP, GP Holdings, AAP, PAA GP LLC and GP LLC to address, among other things, potential conflicts with respect to business opportunities that may arise among PAGP, GP Holdings, AAP, PAA, PAA GP LLC and GP LLC. The agreement provides that if any business opportunity is presented to PAGP, GP Holdings, AAP, PAA, PAA GP LLC or GP LLC, then PAA will have the first right to pursue such business opportunity. PAGP will have the right to pursue and/or participate in such business opportunity if invited to do so by PAA, or if PAA abandons the business opportunity and GP LLC so notifies GP Holdings.

Pursuant to the Administrative Agreement, all of PAGP s officers and other personnel necessary for its business to function (to the extent not out-sourced) are employed by GP LLC, and AAP pays GP LLC an annual fee for general and administrative services performed on behalf of PAGP. The initial fee of $1.5 million per year is subject to adjustment on an annual basis based on the Consumer Price Index. The fee is also subject to adjustment if a material event occurs that impacts the general and administrative services provided to PAGP, such as acquisitions, entering into new lines of business or changes in laws, regulations, listing requirements or accounting rules.

In addition, the Administrative Agreement provides that any direct expenses incurred by PAGP, GP Holdings and AAP (other than income taxes payable by PAGP) are borne by AAP. These direct expenses include costs related to (i) compensation for new directors, (ii) incremental director and officer liability insurance, (iii) listing on the NYSE, (iv) investor relations, (v) legal, (vi) tax and (vii) accounting.

Table of Contents

In addition to the fee and expenses described above, the Administrative Agreement requires AAP to reimburse GP LLC for any additional expenses incurred by GP LLC and certain of its affiliates (i) on PAGP s behalf, (ii) on behalf of GP Holdings, or (iii) for any other purpose related to PAGP s business and activities or those of GP Holdings. AAP is also required to reimburse GP Holdings for any additional expenses incurred by it on PAGP s behalf or to maintain PAGP s legal existence and good standing. There is no limit on the amount of fees and expenses AAP may be required to pay to affiliates of GP Holdings on PAGP s behalf pursuant to the Administrative Agreement.

Pursuant to the Administrative Agreement, PAA has also granted PAGP a license to use the names PAA and Plains and any associated or related marks.

Transactions with Related Persons

On November 14, 2014, we acquired a 50% interest in BridgeTex Pipeline Company, LLC (BridgeTex) from Occidental for $1.088 billion, including working capital adjustments of $13 million. BridgeTex owns a 300,000 barrel-per-day crude oil pipeline that extends from Colorado City in West Texas to a crude oil terminal in East Houston and is complementary to our existing West Texas assets. Occidental is the primary shipper on the BridgeTex pipeline.

During 2014, we recognized sales and transportation and storage revenues of approximately $1.2 billion from companies affiliated with Occidental. During 2014, we also purchased approximately $0.9 billion of petroleum products from companies affiliated with Occidental. These transactions were conducted at posted tariff rates or prices that we believe approximate market. These amounts do not include revenues from unconsolidated equity investments.

During 2014, we purchased approximately $6.2 million 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.

An employee in our marketing department is the son of Phil Kramer, one of our executive officers. His total compensation for 2014 (which amount includes the grant date fair value of LTIPs awarded to him on terms consistent with all eligible employees) was approximately $318,000.

An employee with our Canadian operations is the son of W. David Duckett, one of our executive officers. His total compensation for 2014 (which amount includes the grant date fair value of LTIPs awarded to him on terms consistent with all eligible employees) was approximately $312,000.

Review, Approval or Ratification of Transactions with Related Persons

Pursuant to our Governance Guidelines, a director is expected to bring to the attention of the CEO or the board any conflict or potential conflict of interest that may arise between the director or any affiliate of the director, on the one hand, and the Partnership 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 of directors of our general partner 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 of our general partner.

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 board approval 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 of such committee.

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 for services provided to us and to our consolidated subsidiaries (in millions):

	Year Ended December 31, 2014		2013	
Audit fees (1)	$	4.4	$	4.4
Audit-related fees (2)		0.1		0.1
Tax fees (3)		1.8		1.5
All other fees (4)				0.2
Total	$	6.3	$	6.2

(1) Audit fees include those related to (a) our annual audit (including internal control evaluation and reporting); (b) the annual audit of PNG; (c) the audit of certain joint ventures of which we are the operator, and (d) work performed on our registration of publicly held debt and equity.

(2) Audit-related fees are for an audit of our benefit plan.

(3) Tax fees are related to tax processing as well as the preparation of Forms K-1 for our unitholders and international tax planning work associated with the structure of our Canadian investment.

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

Pre-Approval Policy

As discussed above, we have an audit committee that reviews our external financial reporting, engages our independent auditors and reviews the adequacy of our internal accounting controls. Prior to the PNG Merger on December 31, 2013, our consolidated subsidiary, PNG, also had an audit committee that performed similar functions on PNG s behalf. All services provided by our independent auditor are subject to pre-approval by our audit committee (or the audit committee of PNG (for services provided to PNG)). The audit committees have instituted policies that describe certain pre-approved non-audit services. We believe that the descriptions of services are designed to be sufficiently detailed as to particular services provided, such that (i) management is not required to exercise judgment as to whether a proposed service fits within the description and (ii) the audit committee knows what services it is being asked to pre-approve. The audit committees are informed of each engagement of the independent auditor to provide services under the respective policy. All services provided by our independent auditor during the years ended December 31, 2014 and 2013 were approved in advance by the applicable audit committee.

Table of Contents

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) **(1)** *Financial Statements*

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

(2) *Financial Statement Schedules*

All schedules are omitted because they are either not applicable or the required information is shown in the Consolidated Financial Statements or notes thereto.

(3) *Exhibits*

The exhibits listed on the accompanying Exhibit Index are filed or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

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 25, 2015		
	By:	/s/ Al Swanson **Al Swanson,** ***Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)***
February 25, 2015		
	By:	/s/ Chris Herbold **Chris Herbold,** ***Vice President Accounting and Chief Accounting Officer of Plains All American GP LLC (Principal Accounting Officer)***
February 25, 2015		

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 25, 2015
/s/ Harry N. Pefanis Harry N. Pefanis	President and Chief Operating Officer of Plains All American GP LLC	February 25, 2015
/s/ Al Swanson Al Swanson	Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)	February 25, 2015
/s/ Chris Herbold Chris Herbold	Vice President Accounting and Chief Accounting Officer of Plains All American GP LLC (Principal Accounting Officer)	February 25, 2015
/s/ Bernard Figlock Bernard Figlock	Director of Plains All American GP LLC	February 25, 2015
/s/ Everardo Goyanes Everardo Goyanes	Director of Plains All American GP LLC	February 25, 2015
/s/ Gary R. Petersen Gary R. Petersen	Director of Plains All American GP LLC	February 25, 2015
/s/ John T. Raymond John T. Raymond	Director of Plains All American GP LLC	February 25, 2015
/s/ Robert V. Sinnott Robert V. Sinnott	Director of Plains All American GP LLC	February 25, 2015
/s/ J. Taft Symonds J. Taft Symonds	Director of Plains All American GP LLC	February 25, 2015
/s/ Christopher M. Temple Christopher M. Temple	Director of Plains All American GP LLC	February 25, 2015

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, 2014 and 2013	F-4
Consolidated Statements of Operations for the years ended December 31, 2014, 2013 and 2012	F-5
Consolidated Statements of Comprehensive Income for the years ended December 31, 2014, 2013 and 2012	F-6
Consolidated Statements of Changes in Accumulated Other Comprehensive Income / (Loss) for the years ended December 31, 2014, 2013 and 2012	F-6
Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012	F-7
Consolidated Statements of Changes in Partners Capital for the years ended December 31, 2014, 2013 and 2012	F-8
Notes to the Consolidated Financial Statements:	F-9
1. Organization and Basis of Presentation	F-9
2. Summary of Significant Accounting Policies	F-10
3. Acquisitions and Dispositions	F-14
4. Net Income Per Limited Partner Unit	F-15
5. Inventory, Linefill and Base Gas and Long-term Inventory	F-17
6. Property and Equipment	F-18
7. Goodwill	F-20
8. Investments in Unconsolidated Entities	F-21
9. Other Assets, Net	F-22
10. Debt	F-23
11. Partners Capital and Distributions	F-26
12. Derivatives and Risk Management Activities	F-28
13. Income Taxes	F-36
14. Major Customers and Concentration of Credit Risk	F-37
15. Related Party Transactions	F-38
16. Equity-Indexed Compensation Plans	F-39
17. Commitments and Contingencies	F-42
18. Quarterly Financial Data (Unaudited)	F-45
19. Operating Segments	F-45

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 has 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 (2013) 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, 2014.

The effectiveness of the Partnership s internal control over financial reporting as of December 31, 2014 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on Page F-3.

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

/s/ Al Swanson
Al Swanson
Executive Vice President and Chief Financial Officer of Plains All American GP LLC
(Principal Financial Officer)

February 24, 2015

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 comprehensive income, of changes in accumulated other comprehensive income / (loss), of changes in partners capital, and of cash flows present fairly, in all material respects, the financial position of Plains All American Pipeline, L.P. and its subsidiaries at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 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, 2014, based on criteria established in *Internal Control Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Partnership s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP
Houston, Texas
February 24, 2015

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in millions, except unit data)

	December 31, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 403	$ 41
Trade accounts receivable and other receivables, net	2,615	3,638
Inventory	891	1,065
Other current assets	270	220
Total current assets	4,179	4,964
PROPERTY AND EQUIPMENT	14,178	12,473
Accumulated depreciation	(1,906)	(1,654)
Property and equipment, net	12,272	10,819
OTHER ASSETS		
Goodwill	2,465	2,503
Investments in unconsolidated entities	1,735	485
Linefill and base gas	930	798
Long-term inventory	186	251
Other, net	489	540
Total assets	$ 22,256	$ 20,360
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 2,986	$ 3,983
Short-term debt	1,287	1,113
Other current liabilities	482	315
Total current liabilities	4,755	5,411
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discount of $18 and $15, respectively	8,757	6,710
Other long-term debt	5	5
Other long-term liabilities and deferred credits	548	531
Total long-term liabilities	9,310	7,246
COMMITMENTS AND CONTINGENCIES (NOTE 17)		
PARTNERS CAPITAL		
Common unitholders (375,107,793 and 359,133,200 units outstanding, respectively)	7,793	7,349
General partner	340	295
Total partners capital excluding noncontrolling interests	8,133	7,644
Noncontrolling interests	58	59
Total partners capital	8,191	7,703
Total liabilities and partners capital	$ 22,256	$ 20,360

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, 2014	2013	2012
REVENUES			
Supply and Logistics segment revenues	$ 42,114	$ 40,692	$ 36,438
Transportation segment revenues	774	701	623
Facilities segment revenues	576	856	736
Total revenues	43,464	42,249	37,797
COSTS AND EXPENSES			
Purchases and related costs	39,500	38,465	34,368
Field operating costs	1,456	1,322	1,180
General and administrative expenses	325	359	342
Depreciation and amortization	392	375	482
Total costs and expenses	41,673	40,521	36,372
OPERATING INCOME	1,791	1,728	1,425
OTHER INCOME/(EXPENSE)			
Equity earnings in unconsolidated entities	108	64	38
Interest expense (net of capitalized interest of $48, $38 and $36, respectively)	(340)	(303)	(288)
Other income/(expense), net	(2)	1	6
INCOME BEFORE TAX	1,557	1,490	1,181
Current income tax expense	(71)	(100)	(53)
Deferred income tax benefit/(expense)	(100)	1	(1)
NET INCOME	1,386	1,391	1,127
Net income attributable to noncontrolling interests	(2)	(30)	(33)
NET INCOME ATTRIBUTABLE TO PAA	$ 1,384	$ 1,361	$ 1,094
NET INCOME ATTRIBUTABLE TO PAA:			
LIMITED PARTNERS	$ 884	$ 967	$ 789
GENERAL PARTNER	$ 500	$ 394	$ 305
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 2.39	$ 2.82	$ 2.41
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 2.38	$ 2.80	$ 2.40
BASIC WEIGHTED AVERAGE LIMITED PARTNER UNITS OUTSTANDING	367	341	325
DILUTED WEIGHTED AVERAGE LIMITED PARTNER UNITS OUTSTANDING	369	343	328

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, 2014	2013	2012
Net income	$ 1,386	$ 1,391	$ 1,127
Other comprehensive income/(loss)	(370)	(177)	26
Comprehensive income	1,016	1,214	1,153
Comprehensive income attributable to noncontrolling interests	(2)	(30)	(30)
Comprehensive income attributable to PAA	$ 1,014	$ 1,184	$ 1,123

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN ACCUMULATED

OTHER COMPREHENSIVE INCOME / (LOSS)

(in millions)

	Derivative Instruments	Translation Adjustments	Total
Balance at December 31, 2011	$ (102)	$ 156	$ 54
Reclassification adjustments	(62)		(62)
Deferred gain on cash flow hedges, net of tax	44		44
Currency translation adjustments		44	44
2012 Activity	(18)	44	26
Balance at December 31, 2012	$ (120)	$ 200	$ 80
Reclassification adjustments	(66)		(66)
Deferred gain on cash flow hedges, net of tax	109		109
Currency translation adjustments		(220)	(220)
2013 Activity	43	(220)	(177)
Balance at December 31, 2013	$ (77)	$ (20)	$ (97)
Reclassification adjustments	4		4
Deferred loss on cash flow hedges, net of tax	(86)		(86)
Currency translation adjustments		(288)	(288)
2014 Activity	(82)	(288)	(370)
Balance at December 31, 2014	$ (159)	$ (308)	$ (467)

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, 2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 1,386	$ 1,391	$ 1,127
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization	392	375	482
Equity-indexed compensation expense	98	116	101
Inventory valuation adjustments	289	7	128
Deferred income tax (benefit)/expense	100	(1)	1
Gain on sales of linefill and base gas	(8)	(7)	(19)
(Gain)/loss on foreign currency revaluation	13	(1)	2
Settlement of terminated interest rate hedging instruments	(7)	8	(112)
Equity earnings in unconsolidated entities	(108)	(64)	(38)
Distributions from unconsolidated entities	105	54	40
Other	11	2	(6)
Changes in assets and liabilities, net of acquisitions:			
Trade accounts receivable and other	1,177	(186)	218
Inventory	(129)	134	(180)
Accounts payable and other current liabilities	(1,315)	126	(504)
Net cash provided by operating activities	2,004	1,954	1,240
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid in connection with acquisitions, net of cash acquired (Note 3)	(10)	(28)	(2,156)
Additions to property, equipment and other	(1,932)	(1,613)	(1,204)
Cash received for sales of linefill and base gas	24	40	65
Cash paid for purchases of linefill and base gas	(161)	(122)	(109)
Investment in unconsolidated entities (Note 8)	(1,246)	(133)	(76)
Proceeds from sales of assets	28	200	22
Cash received upon formation of equity-method investment			59
Other investing activities	1	3	7
Net cash used in investing activities	(3,296)	(1,653)	(3,392)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings/(repayments) under PAA senior secured hedged inventory facility (Note 10)		(660)	591
Net borrowings/(repayments) under PAA senior unsecured revolving credit facility (Note 10)		(92)	59
Net borrowings/(repayments) under PNG credit agreement		(382)	61
Net borrowings/(repayments) under PAA commercial paper program (Note 10)	(366)	1,110	
Proceeds from the issuance of PAA senior notes (Note 10)	2,595	699	1,996
Repayments of PAA senior notes (Note 10)		(250)	(500)
Net proceeds from the issuance of common units (Note 11)	848	465	959
Contributions from general partner	18	25	20
Net proceeds from the issuance of PNG common units		40	
Distributions paid to common unitholders (Note 11)	(934)	(791)	(684)
Distributions paid to general partner (Note 11)	(473)	(369)	(285)

Distributions paid to noncontrolling interests		(3)		(49)		(48)
Other financing activities		(28)		(27)		(18)
Net cash provided by/(used in) financing activities		1,657		(281)		2,151
Effect of translation adjustment on cash		(3)		(3)		(1)
Net increase/(decrease) in cash and cash equivalents		362		17		(2)
Cash and cash equivalents, beginning of period		41		24		26
Cash and cash equivalents, end of period	$	403	$	41	$	24
Cash paid for:						
Interest, net of amounts capitalized	$	334	$	305	$	295
Income taxes, net of amounts refunded	$	159	$	37	$	71

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	Total Partners
	Units	Amount	Partner	Interests	Interests	Capital
Balance at December 31, 2011	310.8	$ 5,249	$ 201	$ 5,450	$ 524	$ 5,974
Net income		789	305	1,094	33	1,127
Distributions		(684)	(285)	(969)	(48)	(1,017)
Issuance of common units	23.5	959	20	979		979
Issuance of common units under LTIP, net of units tendered by employees to satisfy tax withholding obligations	1.0	33	1	34		34
Equity-indexed compensation expense		18	6	24	4	28
Distribution equivalent right payments		(4)		(4)	(1)	(5)
Other comprehensive income/(loss)		28	1	29	(3)	26
Balance at December 31, 2012	335.3	$ 6,388	$ 249	$ 6,637	$ 509	$ 7,146
Net income		967	394	1,361	30	1,391
Distributions		(791)	(369)	(1,160)	(49)	(1,209)
Issuance of common units	8.6	468	9	477		477
Issuance of common units under LTIP, net of units tendered by employees to satisfy tax withholding obligations	0.5	(11)	1	(10)		(10)
Equity-indexed compensation expense		33	5	38	1	39
Distribution equivalent right payments		(5)		(5)	(1)	(6)
Other comprehensive loss		(173)	(4)	(177)		(177)
Issuance of PNG common units		8		8	32	40
PNG Merger (Note 11)	14.7	465	10	475	(463)	12
Balance at December 31, 2013	359.1	$ 7,349	$ 295	$ 7,644	$ 59	$ 7,703
Net income		884	500	1,384	2	1,386
Distributions		(934)	(473)	(1,407)	(3)	(1,410)
Issuance of common units	15.4	848	18	866		866
Issuance of common units under LTIP, net of units tendered by employees to satisfy tax withholding obligations	0.6	(17)	1	(16)		(16)
Equity-indexed compensation expense		32	7	39		39
Distribution equivalent right payments		(6)		(6)		(6)
Other comprehensive loss		(362)	(8)	(370)		(370)
Other		(1)		(1)		(1)
Balance at December 31, 2014	375.1	$ 7,793	$ 340	$ 8,133	$ 58	$ 8,191

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 and unless the context indicates otherwise, the terms Partnership, Plains, PAA, we, us, our, ours and similar terms refer to Plains All American Pipeline, L.P. and its subsidiaries.

We own and operate midstream energy infrastructure and provide logistics services for crude oil, natural gas liquids (NGL), natural gas and refined products. The term NGL includes ethane and natural gasoline products as well as products commonly referred to as liquefied petroleum gas (LPG), such as propane and butane. When used in this Form 10-K, NGL refers to all NGL products including LPG. We own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. Our business activities are conducted through three operating segments: Transportation, Facilities and Supply and Logistics. See Note 19 for further discussion of our 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. (AAP), a Delaware limited partnership. In addition to its ownership of PAA GP LLC, AAP also owns all of our incentive distribution rights (IDRs). Plains All American GP LLC (GP LLC), a Delaware limited liability company, is AAP s general partner. Plains GP Holdings, L.P. (PAGP) is the sole member of GP LLC, and at December 31, 2014, owned an approximate 34.1% limited partner interest in AAP.

GP LLC manages our operations and activities and employs our domestic officers and personnel. Our Canadian officers and personnel are employed by our subsidiary, Plains Midstream Canada ULC (PMC). References to our general partner, as the context requires, include any or all of PAA GP LLC, AAP and GP LLC.

Definitions

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

AOCI	=	Accumulated other comprehensive income / (loss)
Bcf	=	Billion cubic feet

Btu	=	British thermal unit
CAD	=	Canadian dollar
CERCLA	=	Federal Comprehensive Environmental Response, Compensation and Liability Act, as amended
DERs	=	Distribution equivalent rights
EBITDA	=	Earnings before interest, taxes, depreciation and amortization
FASB	=	Financial Accounting Standards Board
GAAP	=	Generally accepted accounting principles in the United States
ICE	=	Intercontinental Exchange
IPO	=	Initial public offering
LIBOR	=	London Interbank Offered Rate
LTIP	=	Long-term incentive plan
Mcf	=	Thousand cubic feet
MLP	=	Master limited partnership
MQD	=	Minimum quarterly distribution
NYMEX	=	New York Mercantile Exchange
NYSE	=	New York Stock Exchange
Oxy	=	Occidental Petroleum Corporation or its subsidiaries
PLA	=	Pipeline loss allowance
PNG	=	PAA Natural Gas Storage, L.P.
RCRA	=	Federal Resource Conservation and Recovery Act, as amended
USD	=	United States dollar
WTI	=	West Texas Intermediate

Table of Contents

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present and discuss our consolidated financial position as of December 31, 2014 and 2013, and the consolidated results of our operations, cash flows, changes in partners capital, comprehensive income and changes in accumulated other comprehensive income / (loss) for the years ended December 31, 2014, 2013 and 2012. All significant intercompany transactions have been eliminated in consolidation, and certain reclassifications have been made to information from previous years to conform to the current presentation. These reclassifications do not affect net income attributable to PAA. The accompanying consolidated financial statements include PAA and all of its wholly owned subsidiaries.

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

PNG Merger

On December 31, 2013, with the approval of PNG s common unitholders, PNG became our wholly-owned subsidiary through a unit-for-unit exchange (referred to herein as the PNG Merger). See Note 11 for further discussion. Since we historically consolidated PNG for financial reporting purposes, the PNG Merger did not change the basis of consolidation of our historical financial statements.

Two-for-One Unit Split

A two-for-one split of our common units was completed on October 1, 2012. The effect of the two-for-one split has been retroactively applied to all unit and per-unit data presented in this Form 10-K. In addition, our partnership agreement was amended to modify certain definitions related to target distribution amounts and minimum distribution amounts to reflect the unit split.

Note 2 Summary of Significant Accounting Policies

Use of Estimates

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

Revenue Recognition

Supply and Logistics Segment Revenues. Revenues from sales of crude oil, NGL and natural gas are recognized at the time title to the product sold transfers to the purchaser, which occurs upon delivery of the product to the purchaser or its designee. Sales of crude oil and NGL consist of outright sales contracts. Inventory purchases and sales under buy/sell transactions are treated as inventory exchanges. The sales under these exchanges are netted to zero in 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 in AOCI and recognized in revenues in the periods during which the underlying physical hedged transaction impacts earnings. Also, the ineffective portion of the change in fair value of cash flow hedges is recognized in revenues each period along with the change in fair value of derivatives that do not qualify for or are not designated for hedge accounting.

Table of Contents

Transportation Segment Revenues. Our Transportation segment operations generally consist of fee-based activities associated with transporting crude oil and NGL on pipelines, gathering systems, trucks and barges. Revenues from pipeline tariffs and fees are associated with the transportation of crude oil and NGL at a published tariff, as well as revenues associated with agreements for committed space on various assets. 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 fees are recognized in the month to which the fee applies. The majority of our pipeline tariff and fee revenues are based on actual volumes and rates. As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor that is intended to offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. In addition, we have certain agreements that require counterparties to ship a minimum volume over an agreed upon period. Revenue is recognized at the latter of when the volume is shipped (pursuant to specifications outlined in the tariffs) or when the counterparty s ability to make up the minimum volume has expired.

Facilities Segment Revenues. Our Facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products, NGL and natural gas, as well as NGL fractionation and isomerization services and natural gas and condensate processing services. Revenues generated in this segment include (i) fees that are generated from storage capacity agreements, (ii) terminal throughput fees that are generated when we receive crude oil, refined products or NGL from one connecting source and deliver the applicable product to another connecting carrier, (iii) loading and unloading fees at our rail terminals, (iv) fees from NGL fractionation and isomerization, (v) fees from natural gas and condensate processing services and (vi) fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing services.

We generate revenue through a combination of month-to-month and multi-year agreements 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 (including throughput and rail fees) are recognized as the crude oil, NGL or refined product enters or exits the terminal and is received from or delivered to the connecting carrier or third-party terminal, as applicable. Hub service fees are recognized in the period the natural gas moves across our header system. Fees from NGL fractionation, isomerization services and gas processing services are recognized in the period when the services are performed. 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, NGL and natural gas obtained in outright purchases, (ii) fees incurred for third-party storage and transportation, whether by pipeline, truck, rail, ship or barge, (iii) interest cost attributable to borrowings for inventory stored in a contango market and (iv) performance-related bonus costs. These costs are recognized when incurred except in the case of products purchased, which are recognized at the time title transfers to us. Purchases that are part of exchanges under buy/sell transactions are netted with the related sales, with any margin presented in Purchases and related costs in our Consolidated Statements of Operations.

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

Foreign Currency Transactions/Translation

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

Table of Contents

Certain of our subsidiaries also enter into transactions and have monetary assets and liabilities that are denominated in a currency other than the entities respective functional currencies. Gains and losses from the revaluation of foreign currency transactions and monetary assets and liabilities are included in the Consolidated Statements of Operations. The revaluation of foreign currency transactions and monetary assets and liabilities resulted in a loss of $13 million for the year ended December 31, 2014, a gain of $1 million for the year ended December 31, 2013 and a loss of $2 million for the year ended December 31, 2012.

Cash and Cash Equivalents

Cash and cash equivalents consist of all unrestricted demand deposits and funds invested in highly liquid instruments with original maturities of three months or less and typically exceed federally insured limits. We periodically assess the financial condition of the institutions where these funds are held and believe that our credit risk is minimal. We used the cash on hand at December 31, 2014 to repay $400 million of commercial paper borrowings during the first week of January 2015.

In accordance with our policy, outstanding checks are classified as accounts payable rather than negative cash. As of December 31, 2014 and 2013, accounts payable included $94 million and $70 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 NGL and natural gas storage. These purchasers include, but are not limited to, refiners, 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 late 2014 and early 2015, commodity prices dropped significantly. This volatility has caused liquidity issues impacting many energy companies, which in turn has increased the potential credit risks associated with certain counterparties with which we do business. To mitigate credit risk related to our accounts receivable, we have in place a rigorous credit review process. We closely monitor market conditions to make a determination with respect to the amount, if any, of open 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 advance cash payments, standby letters of credit or parental guarantees. As of December 31, 2014 and 2013, we had received $180 million and $117 million, respectively, of advance cash payments from third parties to mitigate credit risk. Furthermore, as of December 31, 2014 and 2013, we had received $198 million and $426 million, respectively, of standby letters of credit to support obligations due from third parties, a portion of which applies to future business. In addition, in an effort to mitigate credit risk, a significant portion of our transactions with counterparties are settled on a net-cash basis. Further, we enter into netting agreements (contractual agreements that allow us to offset receivables and payables with those counterparties against each other on our balance sheet) for a majority of such arrangements.

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. We do not apply actual balances against the reserve until we have exhausted substantially all collection efforts. At December 31, 2014 and 2013, substantially all of our accounts receivable (net of allowance for doubtful accounts) were less than 30 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled $4 million and $5 million at December 31, 2014 and 2013, respectively. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

Noncontrolling Interests

We account for noncontrolling interests in subsidiaries in accordance with FASB guidance, which requires all entities to report noncontrolling interests in subsidiaries as a component of equity in the consolidated financial statements. Noncontrolling interest represents the portion of assets and liabilities in a consolidated subsidiary that is owned by a third-party. See Note 11 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.

Table of Contents

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 $36 million and $34 million, respectively, at December 31, 2014 and 2013.

Fair Value Measurements

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which affects the placement of assets and liabilities within the fair value hierarchy levels. The determination of the fair values includes not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit) but also the impact of our nonperformance risk on our liabilities. The fair value of our commodity derivatives, interest rate derivatives and foreign currency derivatives includes adjustments for credit risk. Our credit adjustment methodology uses market observable inputs and requires judgment. There were no changes to any of our valuation techniques during the period. See Note 12 for further discussion.

Other Significant Accounting Policies

See the respective footnotes for our accounting policies regarding (i) acquisitions, (ii) net income per limited partner unit, (iii) inventory, linefill and base gas and long-term inventory, (iv) property and equipment, (v) goodwill, (vi) investments in unconsolidated entities, (vii) other assets, net, (viii) derivatives and risk management activities, (ix) income taxes, (x) equity-indexed compensation and (xi) legal and environmental matters.

Recent Accounting Pronouncements

In January 2015, as part of its initiative to reduce complexity in accounting standards, the FASB issued guidance to eliminate the concept of extraordinary items from GAAP. This guidance will become effective for interim and annual periods beginning after December 15, 2015. We expect to adopt this guidance on January 1, 2016. We do not believe our adoption will have a material impact on our financial position, results of operations or cash flows.

In May 2014, the FASB issued guidance regarding the recognition of revenue from contracts with customers with the underlying principle that an entity will recognize revenue to reflect amounts expected to be received in exchange for the provision of goods and services to customers upon the transfer of those goods or services. The guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue and the related cash flows. This guidance becomes effective for interim and annual periods beginning after December 15, 2016 and can be adopted either with a full retrospective approach or a modified retrospective approach with a cumulative-effect adjustment as of the date of adoption. We are currently evaluating which transition approach to apply and the effect that adopting this guidance will have on our financial position, results of operations and cash flows.

In April 2014, the FASB issued guidance that modifies the criteria under which assets to be disposed of are evaluated to determine if such assets qualify as a discontinued operation and requires new disclosures for both discontinued operations and certain other disposals that do not meet the definition of a discontinued operation. This guidance is effective prospectively for annual and interim reporting periods beginning after December 15, 2014. Early adoption is permitted but only for disposals (or classifications as held for sale) that have not been reported in financial statements previously issued or available for issue. We adopted this guidance on January 1, 2015. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

Table of Contents

In March 2013, the FASB issued guidance regarding the release of cumulative translation adjustments into net income when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets that is a business within a foreign entity. This guidance became effective beginning after December 15, 2013. We adopted this guidance on January 1, 2014. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

Note 3 Acquisitions and Dispositions

2014 Acquisitions

Acquisition of Interest in BridgeTex Pipeline Company, LLC

On November 14, 2014, we acquired a 50% interest in BridgeTex Pipeline Company, LLC (BridgeTex) from Oxy. We account for this investment under the equity method of accounting. See Note 8 for additional discussion.

The following acquisitions were accounted for using the acquisition method of accounting and the determination of the fair value of the assets and liabilities acquired has been estimated in accordance with the applicable accounting guidance.

Other 2014 Acquisitions

During the year ended December 31, 2014, we completed two additional acquisitions for aggregate consideration of $11 million. The assets acquired primarily included a crude oil terminal and a propane terminal included in our Facilities segment. We recognized goodwill of $1 million related to these acquisitions.

2013 Acquisitions

During the year ended December 31, 2013, we completed an acquisition for aggregate consideration of $19 million. The assets acquired included a trucking business included in our Transportation segment. We recognized goodwill of $6 million related to this acquisition.

2012 Acquisitions

BP NGL Acquisition

On April 1, 2012, we acquired all of the outstanding shares of BP Canada Energy Company, a wholly owned subsidiary of BP Corporation North America Inc. from Amoco Canada International Holdings B.V. Total consideration for this acquisition (referred to herein as the BP NGL Acquisition), which was based on an October 1, 2011 effective date, was approximately $1.68 billion in cash, including $17 million of imputed interest.

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

Description		**Amount**	**Average Depreciable Life (in years)**
Working capital	$	241	N/A
Property and equipment		1,081	5 - 70
Linefill		85	N/A
Long-term inventory		165	N/A
Intangible assets (contract)		130	13
Goodwill		236	N/A
Deferred tax liability		(236)	N/A
Environmental liability		(14)	N/A
Other long-term liabilities		(5)	N/A
Total	$	1,683	

Table of Contents

The purchase price was equal to the fair value of the net tangible and intangible assets acquired, excluding the resulting deferred tax liability and goodwill. The deferred tax liability is determined by the difference between the fair value of the acquired assets and liabilities and the tax basis for those assets and liabilities. The resulting liability gives rise to an equal and offsetting goodwill balance for this transaction.

The BP NGL Acquisition was pre-funded through various means, including the issuance of common units and senior notes in March 2012 for net proceeds of approximately $1.69 billion. During the year ended December 31, 2012, we incurred $13 million of acquisition-related costs associated with the BP NGL Acquisition. Such costs are reflected as a component of General and administrative expenses in our Consolidated Statement of Operations.

USD Rail Terminal Acquisition

On December 12, 2012, we completed a transaction with U.S. Development Group (referred to herein as the USD Rail Terminal Acquisition) for an aggregate consideration of $503 million, paid in cash. Through the USD Rail Terminal Acquisition, we acquired four operating crude oil rail terminals and one terminal under development. The determination of the fair value of the assets and liabilities acquired was $1 million of working capital, $76 million of property and equipment and $426 million of goodwill. The goodwill arising from the USD Rail Terminal Acquisition represents anticipated opportunities to generate future cash flows from the rail facilities by utilizing them to reduce capacity constraints in certain geographic market areas.

Other 2012 Acquisitions

During the year ended December 31, 2012, we completed several additional acquisitions for an aggregate consideration of $150 million. The assets acquired primarily included crude oil and condensate gathering pipelines, a truck unloading terminal and trailers that are utilized in our Transportation segment, and terminal facilities included in our Facilities segment. We recognized goodwill of $10 million related to these acquisitions.

Pro Forma Results

Disclosure of the revenues and earnings from the BP NGL Acquisition, USD Rail Terminal Acquisition and our other 2012 acquisitions in our results for the year ended December 31, 2012 is not practicable as they were not operated as standalone subsidiaries. Selected unaudited pro forma results of operations for the year ended December 31, 2012, assuming our 2012 acquisitions had occurred on January 1, 2012, are presented below (in millions, except per unit data):

		Year Ended December 31, 2012
Total revenues	$	38,729
Net income attributable to PAA	$	1,149
Limited partner interest in net income attributable to PAA	$	846

Net income per limited partner unit:		
Basic	$	2.57
Diluted	$	2.55

Dispositions

During 2014, 2013 and 2012, we sold various property and equipment for proceeds totaling $28 million, $200 million and $22 million, respectively. Gains of $1 million, less than $1 million and $6 million were recognized in 2014, 2013 and 2012, respectively, related to these sales.

Our 2013 dispositions primarily included the sale of certain refined products pipeline systems and related assets included in our Transportation segment. We closed a portion of the transaction in July 2013 and the balance in November 2013.

Note 4 Net Income Per Limited Partner Unit

Basic and diluted net income per limited partner unit is determined pursuant to the two-class method for MLPs as prescribed in FASB guidance. The two-class method is an earnings allocation formula that is used to determine earnings to our general partner, common unitholders and participating securities according to distributions pertaining to the current period s net income and participation rights in undistributed earnings. Under this method, all earnings are allocated to our general

Table of Contents

partner, common unitholders and participating securities based on their respective rights to receive distributions, regardless of whether those earnings would actually be distributed during a particular period from an economic or practical perspective.

We calculate basic and diluted net income per limited partner unit by dividing net income attributable to PAA (after deducting the amount allocated to the general partner s interest, IDRs and participating securities) by the basic and diluted weighted-average number of limited partner units outstanding during the period. Participating securities include LTIP awards that have vested DERs, which entitle the grantee to a cash payment equal to the cash distribution paid on our outstanding common units.

Diluted net income per limited partner unit is computed based on the weighted average number of units plus the effect of dilutive potential units outstanding during the period using the two-class method. Our LTIP awards 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. See Note 16 for a complete discussion of our LTIP awards including specific discussion regarding DERs.

The following table sets forth the computation of basic and diluted net income per limited partner unit for the years ended December 31, 2014, 2013 and 2012 (in millions, except per unit data):

	Year Ended December 31,					
	2014		2013		2012	
Basic Net Income per Limited Partner Unit						
Net income attributable to PAA	$	1,384	$	1,361	$	1,094
Less: General partner s incentive distribution (1)		(482)		(375)		(289)
Less: General partner 2% ownership (1)		(18)		(19)		(16)
Net income available to limited partners		884		967		789
Less: Undistributed earnings allocated and distributions to participating securities (1)		(6)		(7)		(5)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$	878	$	960	$	784
Basic weighted average limited partner units outstanding		367		341		325
Basic net income per limited partner unit	$	2.39	$	2.82	$	2.41
Diluted Net Income per Limited Partner Unit						
Net income attributable to PAA	$	1,384	$	1,361	$	1,094
Less: General partner s incentive distribution (1)		(482)		(375)		(289)
Less: General partner 2% ownership (1)		(18)		(19)		(16)
Net income available to limited partners		884		967		789
Less: Undistributed earnings allocated and distributions to participating securities (1)		(6)		(6)		(4)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$	878	$	961	$	785
Basic weighted average limited partner units outstanding		367		341		325
Effect of dilutive securities: Weighted average LTIP units		2		2		3

Diluted weighted average limited partner units outstanding		369		343		328
Diluted net income per limited partner unit	$	2.38	$	2.80	$	2.40

---

(1) We calculate net income available to limited partners based on the distributions pertaining to the current period s net income. After adjusting for the appropriate period s distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner, limited partners and participating securities in accordance with the contractual terms of the partnership agreement and as further prescribed under the two-class method.

Table of Contents

Pursuant to the terms of our partnership agreement, the general partner s incentive distribution is limited to a percentage of available cash, which, as defined in the partnership agreement, is net of reserves deemed appropriate. As such, IDRs are not allocated undistributed earnings or distributions in excess of earnings in the calculation of net income per limited partner unit. If, however, undistributed earnings were allocated to our IDRs beyond amounts distributed to them under the terms of the partnership agreement, basic and diluted net income per limited partner unit as reflected in the table above would be impacted as follows:

	Year Ended December 31,		
	2014	2013	2012
Basic net income per limited partner unit impact	$	$ (0.20)	$ (0.11)
Diluted net income per limited partner unit impact	$	$ (0.20)	$ (0.11)

Note 5 Inventory, Linefill and Base Gas and Long-term Inventory

Inventory primarily consists of crude oil, NGL and natural gas in pipelines, storage facilities and railcars 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. Any resulting adjustments are a component of Purchases and related costs on our accompanying Consolidated Statements of Operations. During the years ended December 31, 2014, 2013 and 2012, we recorded charges of $289 million, $7 million and $128 million, respectively, related to the writedown of our crude oil, NGL and natural gas inventory due to declines in prices. The year ended December 31, 2014 included the writedown of our natural gas inventory that was purchased in conjunction with managing natural gas storage deliverability requirements during the extended period of severe cold weather in the first quarter of 2014. A portion of these adjustments were offset by the recognition of gains on derivative instruments being utilized to hedge the future sales of our crude oil and NGL inventory. Substantially all of such gains were recorded to Supply and Logistics segment revenues in our accompanying Consolidated Statement of Operations. In 2014, we recognized $160 million of such gains. A majority of the inventory subject to writedown in the 2013 and 2012 periods had been liquidated and the applicable derivative instruments had been settled by the end of each year. See Note 12 for discussion of our derivative and risk management activities.

Linefill and base gas and minimum working inventory requirements in assets we own are recorded at historical cost and consist of crude oil, NGL and natural gas. We classify as linefill or base gas (i) our proportionate share of barrels used to fill a pipeline that we own such that when an incremental barrel is pumped into or enters a pipeline it forces product out at another location, (ii) barrels that represent the minimum working requirements in tanks and caverns that we own and (iii) natural gas required to maintain the minimum operating pressure of natural gas storage facilities we own. Linefill and base gas carrying amounts are reviewed for impairment in accordance with FASB guidance with respect to accounting for the impairment or disposal of long-lived assets. Carrying amounts that are not expected to be recoverable through future cash flows are written down to estimated fair value. See Note 6 for further discussion regarding impairment of long-lived assets. During 2014, 2013 and 2012, we did not recognize any impairments of linefill and base gas, but we did recognize gains of $8 million, $7 million and $19 million, respectively, on the sale of linefill and base gas for proceeds of $24 million, $40 million and $65 million, respectively.

Minimum working inventory requirements in third-party assets and other working inventory in our assets that are 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 the average cost of the applicable inventory pools, and into long-term inventory, which is reflected as a separate line item in Other assets on our Consolidated Balance Sheet.

Table of Contents

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

	December 31, 2014					December 31, 2013				
	Volumes	Unit of Measure	Carrying Value		Price/ Unit (1)	Volumes	Unit of Measure	Carrying Value		Price/ Unit (1)
Inventory										
Crude oil	6,465	barrels	$ 304	$	47.02	6,951	barrels	$ 540	$	77.69
NGL	13,553	barrels	454	$	33.50	8,061	barrels	352	$	43.67
Natural gas	32,317	Mcf	102	$	3.16	40,505	Mcf	150	$	3.70
Other	N/A		31		N/A	N/A		23		N/A
Inventory subtotal			891					1,065		
Linefill and base gas										
Crude oil	11,810	barrels	744	$	63.00	10,966	barrels	679	$	61.92
NGL	1,212	barrels	52	$	42.90	1,341	barrels	62	$	46.23
Natural gas	28,612	Mcf	134	$	4.68	16,615	Mcf	57	$	3.43
Linefill and base gas subtotal			930					798		
Long-term inventory										
Crude oil	2,582	barrels	136	$	52.67	2,498	barrels	202	$	80.86
NGL	1,681	barrels	50	$	29.74	1,161	barrels	49	$	42.20
Long-term inventory subtotal			186					251		
Total			$ 2,007					$ 2,114		

(1) Price per unit of measure is comprised of a weighted average associated with various grades, qualities and locations. Accordingly, these prices may not coincide with any published benchmarks for such products.

Note 6 Property and Equipment

In accordance with our capitalization policy, expenditures made to expand the existing operating and/or earnings capacity of our assets are capitalized. We also capitalize certain costs directly related to the construction of such assets, including related internal labor costs, engineering costs and interest costs. For the years ended December 31, 2014, 2013 and 2012, capitalized interest was $48 million, $38 million and $36 million, respectively. We also capitalize expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets. Repair and maintenance expenditures incurred in order to maintain the day to day operation of our existing assets are expensed as incurred.

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

	Estimated Useful Lives (Years)	December 31, 2014	2013
Pipelines and related facilities	10 - 70	$ 7,003	$ 6,113
Storage, terminal and rail facilities	30 - 70	4,853	4,704
Trucking equipment and other	3 - 15	198	150
Construction in progress	-	1,545	1,008
Office property and equipment	2 - 50	156	125
Land and other	N/A	423	373
		14,178	12,473
Accumulated depreciation		(1,906)	(1,654)
Property and equipment, net		$ 12,272	$ 10,819

We calculate our depreciation using the straight-line method, based on estimated useful lives and salvage values of our assets. Depreciation expense for the years ended December 31, 2014, 2013 and 2012 was $319 million, $259 million and $222 million, respectively. We also classify gains and losses on sales of assets and asset impairments as a component of Depreciation and amortization in our Consolidated Statements of Operations. See Note 3 for additional information regarding dispositions. See Impairment of Long-Lived Assets below for a discussion of our policy for the recognition of asset impairments.

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

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

During the years ended December 31, 2014 and 2013 we recognized impairments of $10 million and $20 million, respectively, related predominantly to assets taken out of service.

During the year ended December 31, 2012, we recognized losses on impairments of long-lived assets of $168 million, primarily related to our Pier 400 terminal project, which is reflected in Depreciation and amortization on our Consolidated Statement of Operations. This project, which we acquired in late 2006 by virtue of our merger with Pacific Energy Partners, L.P., was 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 feedstock. During the third quarter of 2012, we decided not to proceed with the development of this project. A number of factors contributed to the uncertainties with respect to financial returns and the determination not to proceed with the project, including project delays, the economic downturn, regulatory and permitting hurdles, a challenging refining environment in California and an industry shift in the outlook for availability of domestic crude oil.

We assessed the recoverability of these long-lived assets and, where necessary, performed further analysis based on a projected discounted cash flow methodology. As a result of this impairment review, we wrote off a substantial portion of the carrying amount of these long-lived assets, except for the portion that we anticipate we will recover. These project assets were included in our Facilities segment.

Also in 2012, we recognized a loss on impairment as a result of our decision to sell certain refined products pipeline systems and related assets included in the Transportation segment. In accordance with GAAP, we wrote their book value down to their expected sales price. In 2013, we sold these systems and related assets.

Table of Contents

Note 7 Goodwill

Goodwill represents the future economic benefits arising from assets acquired in a business combination that are not individually identified and separately recognized.

In accordance with FASB guidance, we test goodwill at least annually (as of June 30) and on an interim basis if a triggering event occurs, such as an adverse change in business climate, to determine whether 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, quantitative approach to testing goodwill for impairment; however, we may first assess certain qualitative factors to determine whether it is necessary to perform the two-step goodwill impairment test. We did not elect to apply this qualitative assessment during our 2014 annual goodwill impairment test, but proceeded directly to the two-step, quantitative test. In Step 1, we compare the fair value of the reporting unit with the respective book values, including goodwill, by using an income approach based on a discounted cash flow analysis. This approach requires us to make long-term forecasts of future revenues, expenses and other expenditures. Those forecasts require the use of various assumptions and estimates, the most significant of which are net revenues (total revenues less purchases and related costs), operating expenses, general and administrative expenses and the weighted average cost of capital. Fair value of the reporting units is determined using significant unobservable inputs, or Level 3 inputs in the fair value hierarchy. When the fair value is greater than book value, then the reporting unit s goodwill is not considered impaired. If the book value is greater than fair value, then we proceed to Step 2. In Step 2, we compare the implied fair value of the reporting unit s goodwill with the book value. A goodwill impairment loss is recognized if the carrying amount exceeds its fair value.

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

The following table reflects our goodwill by segment and changes in goodwill during the years ended December 31, 2014 and 2013 (in millions):

	Transportation	Facilities	Supply and Logistics	Total
Balance at December 31, 2012	$ 897	$ 1,171	$ 467	$ 2,535
Acquisitions	6			6
Foreign currency translation adjustments	(20)	(9)	(4)	(33)
Purchase price accounting adjustments and other	(5)			(5)
Balance at December 31, 2013	$ 878	$ 1,162	$ 463	$ 2,503
Acquisitions (1)		1		1
Foreign currency translation adjustments	(24)	(11)	(4)	(39)
Balance at December 31, 2014	$ 854	$ 1,152	$ 459	$ 2,465

(1) Goodwill is recorded at the acquisition date based on a preliminary fair value determination. This preliminary goodwill balance may be adjusted when the fair value determination is finalized. See Note 3 for additional discussion of our acquisitions.

Table of Contents

Note 8 Investments in Unconsolidated Entities

Investments in entities over which we have significant influence but not control are accounted for by the equity method. 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 our Consolidated Statements of Operations entitled Equity earnings in unconsolidated entities and will increase or decrease, as applicable, the carrying value of our investments in unconsolidated entities on the balance sheet. In addition, as applicable, 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. We evaluate our equity investments for impairment in accordance with FASB guidance with respect to the equity method of accounting for investments in common stock. An impairment of an equity investment results when factors indicate that the investment s fair value is less than its carrying value and the reduction in value is other than temporary in nature.

We consider distributions received from unconsolidated entities as returns on investment in those entities to the extent of cumulative net operating cash flows, and therefore classify these distributions as cash flows from operating activities in our Consolidated Statement of Cash Flows. We define cumulative net operating cash flows as cumulative net income adjusted for certain non-cash items such as depreciation and amortization expense. Other distributions received from unconsolidated entities would be considered a return of the investment and classified as cash flows from investing activities on the Consolidated Statement of Cash Flows. Our contributions to these entities will increase the carrying value of our investments and are reflected in our Consolidated Statements of Cash Flows in investing activities. During the years ended December 31, 2014, 2013 and 2012, we made cash contributions to Eagle Ford Pipeline LLC and White Cliffs Pipeline, LLC to support construction and expansion activities of such entities.

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

Entity	**Type of Operation**	**Our Ownership Interest**
Settoon Towing, LLC	Barge Transportation Services	50%
BridgeTex Pipeline Company, LLC	Crude Oil Pipeline	50%
Eagle Ford Pipeline LLC	Crude Oil Pipeline	50%
White Cliffs Pipeline, LLC	Crude Oil Pipeline	36%
Butte Pipe Line Company	Crude Oil Pipeline	22%
Frontier Pipeline Company	Crude Oil Pipeline	22%

In August 2012, we formed Eagle Ford Pipeline LLC with Enterprise Products Partners L.P. (Enterprise) for the purpose of developing a crude oil pipeline system in the Eagle Ford Area of South Texas. In conjunction with the formation, we and Enterprise contributed fixed assets with estimated book values of $134 million and $15 million, respectively. In addition, Enterprise contributed cash of $59 million, which we received from Eagle Ford Pipeline LLC.

On November 14, 2014, we acquired a 50% interest in BridgeTex from Oxy. BridgeTex owns a 300,000 barrel-per-day crude oil pipeline that extends from Colorado City in West Texas to a crude oil terminal in East Houston, which we believe is complementary to our existing West Texas assets. We paid cash of $1.088 billion, including working capital adjustments of $13 million, for our interest in BridgeTex.

Our investments in unconsolidated entities exceeded our share of the underlying equity in the net assets of such entities by $763 million and $78 million at December 31, 2014 and 2013, respectively. Such basis differences are included in the carrying values of our investments on our Consolidated Balance Sheets. The portion of the basis differences attributable to depreciable or amortizable assets is amortized on a straight-line basis over the estimated useful life of the related assets, which reduces Equity earnings in unconsolidated entities on our Consolidated Statements of Operations. The portion of the basis differences attributable to goodwill is not amortized. The increase in basis differences in 2014 was primarily due to our acquisition of an interest in BridgeTex.

Table of Contents

Summarized Financial Information of Unconsolidated Entities

Combined summarized financial information for all of our unconsolidated entities is shown in the tables below (in millions):

	December 31, 2014	December 31, 2013
Current assets	$ 184	$ 177
Noncurrent assets	$ 2,303	$ 1,067
Current liabilities	$ 142	$ 57
Noncurrent liabilities	$ 222	$ 211

	Year Ended December 31, 2014	2013	2012
Revenues	$ 531	$ 344	$ 257
Operating income	$ 301	$ 181	$ 132
Net income	$ 285	$ 172	$ 118

Note 9 Other Assets, Net

Other assets, net of accumulated amortization, consisted of the following as of the dates indicated (in millions):

	December 31, 2014	December 31, 2013
Intangible assets	$ 676	$ 674
Debt issue costs	92	70
Fair value of derivative instruments	27	30
Other	19	37
	814	811
Accumulated amortization	(325)	(271)
	$ 489	$ 540

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 $24 million and $9 million in 2014 and 2013, respectively. Gross debt issue costs of $2 million and $8 million were removed from our Consolidated Balance Sheet during 2014 and 2013, respectively.

Amortization expense related to other assets (including finite-lived intangible assets) for the three years ended December 31, 2014, 2013 and 2012 was $64 million, $96 million and $99 million, respectively. Amortization expense for finite-lived intangible assets for the years ended December 31, 2014, 2013 and 2012 was $57 million, $85 million and $90 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 consisted of the following as of the dates indicated (in millions):

		December 31, 2014			December 31, 2013		
	Estimated Useful Lives (Years)	Cost	Accumulated Amortization	Net	Cost	Accumulated Amortization	Net
Customer contracts and relationships	1 - 20	$ 593	$ (288)	$ 305	$ 591	$ (237)	$ 354
Property tax abatement	7 - 13	38	(18)	20	38	(14)	24
Other agreements	25 - 70	37	(4)	33	37	(3)	34
Emission reduction credits (1)	N/A	8		8	8		8
		$ 676	$ (310)	$ 366	$ 674	$ (254)	$ 420

(1) Emission reduction credits, once surrendered in exchange for environmental permits, are finite-lived.

Table of Contents

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

2015	$ 52
2016	$ 44
2017	$ 41
2018	$ 36
2019	$ 33

Note 10 Debt

Debt consisted of the following as of the dates indicated (in millions):

	December 31, 2014	December 31, 2013
SHORT-TERM DEBT		
PAA commercial paper notes, bearing a weighted-average interest rate of 0.46% and 0.33%, respectively (1)	$ 734	$ 1,109
PAA senior notes:		
5.25% senior notes due June 2015	150	
3.95% senior notes due September 2015	400	
Other	3	4
Total short-term debt	1,287	1,113
LONG-TERM DEBT		
PAA senior notes:		
5.25% senior notes due June 2015		150
3.95% senior notes due September 2015		400
5.88% senior notes due August 2016	175	175
6.13% senior notes due January 2017	400	400
6.50% senior notes due May 2018	600	600
8.75% senior notes due May 2019	350	350
2.60% senior notes due December 2019	500	
5.75% senior notes due January 2020	500	500
5.00% senior notes due February 2021	600	600
3.65% senior notes due June 2022	750	750
2.85% senior notes due January 2023	400	400
3.85% senior notes due October 2023	700	700
3.60% senior notes due November 2024	750	
6.70% senior notes due May 2036	250	250
6.65% senior notes due January 2037	600	600
5.15% senior notes due June 2042	500	500
4.30% senior notes due January 2043	350	350
4.70% senior notes due June 2044	700	
4.90% senior notes due February 2045	650	
Unamortized discounts	(18)	(15)
PAA senior notes, net of unamortized discounts	8,757	6,710
Other	5	5
Total long-term debt	8,762	6,715

Total debt (2)	$ 10,049	$ 7,828

(1) At December 31, 2014 and 2013, we classified all of the borrowings under our commercial paper program as short-term as these borrowings are primarily designated as working capital borrowings, must be repaid within one year and are primarily for hedged NGL and crude oil inventory and NYMEX and ICE margin deposits.

(2) Our fixed-rate senior notes (including current maturities) had a face value of approximately $9.3 billion and $6.7 billion as of December 31, 2014 and 2013, respectively. We estimated the aggregate fair value of these notes as of December 31, 2014 and 2013 to be approximately $9.9 billion and $7.2 billion, respectively. Our fixed-rate senior notes are traded among

Table of Contents

institutions, and these trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near year end. We estimate that the carrying value of outstanding borrowings under our credit facilities and commercial paper program approximates fair value as interest rates reflect current market rates. The fair value estimates for our senior notes, credit facilities and commercial paper program are based upon observable market data and are classified within Level 2 of the fair value hierarchy.

Commercial Paper Program

In August 2013, we established a commercial paper program under which we may issue, from time to time, privately placed, unsecured commercial paper notes. Such notes are backstopped by the PAA senior unsecured revolving credit facility and the PAA senior secured hedged inventory facility; as such, any borrowings under our commercial paper program reduce the available capacity under these facilities. In October 2014, the maximum aggregate borrowing capacity was increased from $1.5 billion to $3.0 billion.

Credit Facilities

PAA senior secured hedged inventory facility. The PAA senior secured hedged inventory facility has a committed borrowing capacity of $1.4 billion, of which $400 million is available for the issuance of letters of credit. Subject to obtaining additional or increased lender commitments, the committed amount of the facility may be increased to $1.9 billion. Proceeds from the facility are primarily used to finance purchased or stored hedged inventory, including NYMEX and ICE margin deposits. Such obligations under the committed facility are secured by the financed inventory and the associated accounts receivable and are repaid from the proceeds of the sale of the financed inventory. Borrowings accrue interest based, at our election, on either the Eurocurrency Rate or the Base Rate, in each case plus a margin based on our credit rating at the applicable time. The agreement also provides for one or more one-year extensions, subject to applicable approval. In August 2014, we extended the maturity date of the facility by one year to August 2017 through the exercise of the option included in the current credit agreement.

PAA senior unsecured revolving credit facility. The PAA senior unsecured revolving credit facility has a committed borrowing capacity of $1.6 billion and contains an accordion feature that enables us to increase the committed capacity to $2.1 billion, subject to obtaining additional or increased lender commitments. The credit agreement also provides for the issuance of letters of credit. Borrowings accrue interest based, at our election, on the Eurocurrency Rate, the Base Rate or the Canadian Prime Rate, in each case plus a margin based on our credit rating at the applicable time. The agreement also provides for one or more one-year extensions, subject to applicable approval. In August 2014, we extended the maturity date of the facility by one year to August 2019 through the exercise of the option included in the current credit agreement.

PAA senior unsecured 364-day revolving credit facility. In January 2015, we entered into a 364-day senior unsecured credit agreement with a borrowing capacity of $1.0 billion. Borrowings will accrue interest based, at our election, on either the Eurocurrency Rate or the Base Rate, in each case plus a margin based on our credit rating at the applicable time. The covenants, restrictions and events of default in the credit agreement are substantially the same as those in the PAA senior unsecured revolving credit facility agreement. See -Covenants and Compliance below.

Senior Notes

Our senior notes are co-issued, jointly and severally, by Plains All American Pipeline, L.P. and a 100%-owned consolidated finance subsidiary (neither of which have independent assets or operations) and are unsecured senior obligations of such entities and rank equally in right of payment with existing and future senior indebtedness of the issuers. We may, at our option, redeem any series of senior notes at any time in whole or from time to time in part, prior to maturity, at the redemption prices described in the indentures governing the senior notes. Our senior notes are not guaranteed by any of our subsidiaries.

Table of Contents

Senior Notes Issuances

The table below summarizes our issuances of senior unsecured notes during 2014, 2013 and 2012 (in millions):

Year	Description	Maturity	Face Value		Interest Payment Dates
2014	2.60% Senior Notes issued at 99.813% of face value	December 2019	$	500	June 15 and December 15
2014	4.90% Senior Notes issued at 99.876% of face value	February 2045	$	650	February 15 and August 15
2014	3.60% Senior Notes issued at 99.842% of face value	November 2024	$	750	May 1 and November 1
2014	4.70% Senior Notes issued at 99.734% of face value	June 2044	$	700	June 15 and December 15
2013	3.85% Senior Notes issued at 99.792% of face value	October 2023	$	700	April 15 and October 15
2012	2.85% Senior Notes issued at 99.752% of face value	January 2023	$	400	January 31 and July 31
2012	4.30% Senior Notes issued at 99.925% of face value	January 2043	$	350	January 31 and July 31
2012	3.65% Senior Notes issued at 99.823% of face value	June 2022	$	750	June 1 and December 1
2012	5.15% Senior Notes issued at 99.755% of face value	June 2042	$	500	June 1 and December 1

Senior Note Repayments

On December 13, 2013, we repaid our $250 million, 5.63% senior notes. We utilized cash on hand and available capacity under our commercial paper program to repay these notes.

On September 4, 2012, we repaid our $500 million, 4.25% senior notes. We utilized cash on hand and available capacity under our credit facilities to repay these notes.

Maturities

The weighted average life of our senior notes outstanding at December 31, 2014 was approximately 13 years and the aggregate maturities for the next five years and thereafter are as follows (in millions):

Calendar Year	Payment	
2015	$	550
2016		175
2017		400
2018		600
2019		850
Thereafter		6,750
Total (1)	$	9,325

(1) Excludes aggregate unamortized net discount of $18 million.

Covenants and Compliance

Our credit agreements (which impact our ability to access our commercial paper program because they provide the backstop that supports our short-term credit ratings) and the indentures governing our senior notes contain cross-default provisions. Our credit agreements prohibit declaration or payments of distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, the agreements contain various covenants limiting our ability to, among other things:

- grant liens on certain property;
- incur indebtedness, including capital leases;
- sell substantially all of our assets or enter into a merger or consolidation;
- engage in certain transactions with affiliates; and

- enter into certain burdensome agreements.

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

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

A default under our credit facilities would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit agreements, our ability to make distributions of available cash is not restricted. As of December 31, 2014, we were in compliance with the covenants contained in our credit agreements and indentures.

Borrowings and Repayments

Total borrowings under our credit agreements and commercial paper program for the years ended December 31, 2014, 2013 and 2012 were approximately $70.9 billion, $31.0 billion and $12.9 billion, respectively. Total repayments under our credit agreements and commercial paper program were approximately $71.3 billion, $31.0 billion and $12.2 billion for the years ended December 31, 2014, 2013 and 2012, respectively. The variance in total gross borrowings and repayments is impacted by various business and financial factors including, but not limited to, the timing, average term and method of general partnership borrowing activities.

Letters of Credit

In connection with our supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil, NGL and natural gas. These letters of credit are issued under the PAA senior unsecured revolving credit facility and the PAA senior secured hedged inventory 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, NGL or natural gas is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. Additionally, we issue letters of credit to support insurance programs and construction activities. At December 31, 2014 and 2013, we had outstanding letters of credit of $87 million and $41 million, respectively.

Note 11 Partners Capital and Distributions

Units Outstanding

Partners capital at December 31, 2014 consisted of 375,107,793 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 following 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.

General Partner Distributions. Our general partner is entitled to receive (i) distributions representing its 2% general partner interest and (ii) incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly distribution provisions, the general partner is entitled, without duplication, to 2% of amounts we distribute up to $0.2250 per unit, referred to as our MQD, 15% of amounts we distribute in excess of $0.2250 per unit, 25% of the amounts we distribute in excess of $0.2475 per unit and 50% of amounts we distribute in excess of $0.3375 per unit.

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

Table of Contents

	Year					
	2014		2013		2012	
	Distribution (1)	Excess over MQD	Distribution (1)	Excess over MQD	Distribution (1)	Excess over MQD
First Quarter	$ 0.6150	$ 0.3900	$ 0.5625	$ 0.3375	$ 0.5125	$ 0.2875
Second Quarter	$ 0.6300	$ 0.4050	$ 0.5750	$ 0.3500	$ 0.5225	$ 0.2975
Third Quarter	$ 0.6450	$ 0.4200	$ 0.5875	$ 0.3625	$ 0.5325	$ 0.3075
Fourth Quarter	$ 0.6600	$ 0.4350	$ 0.6000	$ 0.3750	$ 0.5425	$ 0.3175

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

During the years ended December 31, 2014, 2013 and 2012, our general partner s incentive distributions were reduced by approximately $23 million, $15 million and $11 million, respectively. These reductions were agreed to in connection with the BP NGL Acquisition and the PNG Merger. In addition, our general partner has agreed to reduce the amount of its incentive distribution by $5.5 million per quarter during 2015, $5.0 million per quarter in 2016 and $3.75 million per quarter thereafter. See Note 3 for further discussion of the BP NGL Acquisition.

Total cash distributions, net of reductions in our general partner s incentive distributions, paid during the years ended December 31, 2014, 2013 and 2012 were as follows (in millions, except per unit data):

		Distributions Paid			
		General Partner			Distributions
Year	Common Units	2%	Incentive	Total	per limited partner unit
2014	$ 934	$ 19	$ 454	$ 1,407	$ 2.55
2013	$ 791	$ 16	$ 353	$ 1,160	$ 2.33
2012	$ 684	$ 14	$ 271	$ 969	$ 2.11

On January 8, 2015, we declared a cash distribution of $0.6750 per unit on our outstanding common units. The distribution was paid on February 13, 2015 to unitholders of record on January 30, 2015, for the period October 1, 2014 through December 31, 2014. The total distribution paid was $390 million, with $254 million paid to our common unitholders and $5 million and $131 million paid to our general partner for its 2% general partner and incentive distribution interests, respectively.

PAA Equity Offerings

During 2014, 2013 and 2012, we entered into several equity distribution agreements under our Continuous Offering Program, pursuant to which we may offer and sell, through sales agents, common units representing limited partner interests having aggregate offering prices ranging from $300 million to up to $900 million. Sales of such common units are made by means of ordinary brokers transactions on the NYSE at market prices, in block transactions or as otherwise agreed upon by our sales agent and us. In addition to our Continuous Offering Program, we may sell common units through overnight or marketed offerings.

The following table summarizes our issuance of common units in connection with marketed offerings and our Continuous Offering Program during the three years ended December 31, 2014 (net proceeds in millions):

Year	Type of Offering	Units Issued	Net Proceeds (1) (2)	
2014 Total	Continuous Offering Program	15,375,810	$	866(3)
2013 Total	Continuous Offering Program	8,644,807	$	477(3)
2012	Continuous Offering Program	12,063,707	$	524(3)
2012	Marketed Offering	11,500,000		455(4)
2012 Total		23,563,707	$	979

(1) Amounts are net of costs associated with the offerings.

Table of Contents

(2) Amounts include our general partner s proportionate capital contributions of $18 million, $9 million and $20 million during 2014, 2013 and 2012, respectively.

(3) We pay commissions to our sales agents in connection with common unit issuances under our Continuous Offering Program. We paid $9 million, $5 million and $6 million of such commissions during 2014, 2013 and 2012, respectively.

(4) Offering was an underwritten transaction that required us to pay a gross spread. The net proceeds from such offering were used to fund a portion of the BP NGL Acquisition.

Noncontrolling Interests in Subsidiaries

As of December 31, 2014, noncontrolling interests in our subsidiaries consisted of a 25% interest in SLC Pipeline LLC.

PNG Merger

Prior to the PNG Merger, which was completed on December 31, 2013, we owned 100% of the outstanding subordinated units of PNG and approximately 46% of the 61.2 million outstanding common units of PNG. Under the terms of the PNG Merger Agreement, we issued 0.445 PAA common units for each outstanding PNG common unit (the Merger Exchange Ratio) held by unitholders other than us, plus cash in lieu of any fractional PAA common units otherwise issuable in the PNG Merger. Also in conjunction with the PNG Merger, our general partner agreed to reduce the amount of its incentive distributions. See the subsection ***Distributions*** above.

As a result of the PNG Merger, we purchased the noncontrolling interests in PNG for consideration of approximately 14.7 million PAA common units valued at $760 million. Such purchase resulted in an equity-classified loss of $290 million, which we recorded as a decrease to our partners capital. In addition, in conjunction with the PNG Merger, our general partner made a proportional contribution of $16 million associated with our issuance of PAA common units and we incurred transaction costs of $4 million resulting in a net increase in partners capital associated with the PNG Merger of $12 million.

Issuance of PNG Common Units

PNG issued approximately 1.9 million common units during the year ended December 31, 2013. As a result of PNG s common unit issuances, we recorded an increase in noncontrolling interest of $32 million and an increase to our partners capital of $8 million in 2013. These increases represent the portion of the proceeds attributable to the respective ownership interests in PNG, adjusted for the impact of the dilution of our ownership interest. PNG did not issue any common units during the year ended December 31, 2012.

The following table as required by GAAP sets forth the impact on net income attributable to PAA giving effect to the changes in our ownership interest in PNG during 2013 discussed above, which was recognized in partners capital (in millions):

	Year Ended December 31, 2013
Net income attributable to PAA	$ 1,361
Transfers to/from noncontrolling interests:	
Increase in capital from sale of PNG common units	8
Decrease in capital from purchase of PNG common units in conjunction with the PNG Merger	(290)
Net transfers to/from noncontrolling interests	(282)
Change from net income attributable to PAA and transfers to/from noncontrolling interests	$ 1,079

Note 12 Derivatives and Risk Management Activities

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

Commodity Price Risk Hedging

Our core business activities involve certain commodity price-related risks that we manage in various ways, including through the use of derivative instruments. Our policy is to (i) only purchase inventory for which we have a market, (ii) structure our sales contracts so that price fluctuations do not materially affect our operating income and (iii) not acquire and hold physical inventory or derivatives for the purpose of speculating on commodity price changes. The material commodity-related risks inherent in our business activities can be divided into the following general categories:

Commodity Purchases and Sales In the normal course of our operations, we purchase and sell commodities. We use derivatives to manage the associated risks and to optimize profits. As of December 31, 2014, net derivative positions related to these activities included:

- An average of 269,400 barrels per day net long position (total of 8.4 million barrels) associated with our crude oil purchases, which was unwound ratably during January 2015 to match monthly average pricing.

- A net short time spread position averaging approximately 20,500 barrels per day (total of 10.0 million barrels), which hedges a portion of our anticipated crude oil lease gathering purchases through June 2016.

- An average of 33,600 barrels per day (total of 11.2 million barrels) of crude oil grade spread positions through December 2015. These derivatives allow us to lock in grade basis differentials.

- A net short position of approximately 28.1 Bcf through April 2016 related to anticipated sales of natural gas inventory and base gas requirements.

- A net short position of approximately 9.3 million barrels through March 2017 related to the anticipated sales of our crude oil, NGL and refined products inventory.

- A long position of 32,400 barrels per day (total of 1.0 million barrels) through February 2015 related to anticipated crude oil linefill requirements.

Pipeline Loss Allowance Oil As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor that is intended to 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, 2014, our PLA hedges included a net short position for an average of approximately 1,300 barrels per day (total of 0.4 million barrels) through December 2015 and a long call position of approximately 0.8 million barrels through December 2016.

Natural Gas Processing/NGL Fractionation We purchase natural gas for processing and operational needs. Additionally, we purchase NGL mix for fractionation and sell the resulting individual specification products (including ethane, propane, butane and condensate). In conjunction with these activities, we hedge the price risk associated with the purchase of the natural gas and the subsequent sale of the individual specification products. As of December 31, 2014, we had a long natural gas position of approximately 26.1 Bcf through December 2016, a short propane position of approximately 4.1 million barrels through December 2016, a short butane position of approximately 1.2 million barrels through December 2016 and a short WTI position of approximately 0.4 million barrels through December 2016. In addition, we had a long power position of 0.4 million megawatt hours which hedges a portion of our power supply requirements at our natural gas processing and fractionation plants through December 2016.

To the extent they qualify and we decide to make the election, all of our commodity derivatives for which we elect hedge accounting are designated as cash flow hedges. Physical commodity contracts that meet the definition of a derivative but are ineligible, or not designated, for the normal purchases and normal sales scope exception are recorded on the balance sheet at fair value, with changes in fair value recognized in earnings.We have determined that substantially all of our physical purchase and sale agreements qualify for the normal purchases and normal sales scope exception.

Interest Rate Risk Hedging

We use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and outstanding debt instruments. The derivative instruments we use to manage this risk consist primarily of interest rate swaps and treasury locks. As of December 31, 2014, AOCI includes deferred losses of $161 million that relate to open and terminated interest rate derivatives that were designated for hedge accounting. The terminated interest rate derivatives were cash-settled in connection with the issuance or refinancing of debt agreements. The deferred loss related to these instruments is being amortized to interest expense over the terms of the hedged debt instruments.

Table of Contents

We have entered into forward starting interest rate swaps to hedge the underlying benchmark interest rate related to forecasted debt issuances through 2018. The following table summarizes the terms of our forward starting interest rate swaps as of December 31, 2014 (notional amounts in millions):

Hedged Transaction	Number and Types of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Anticipated debt offering	10 forward starting swaps (30-year)	$ 250	6/15/2015	3.60%	Cash flow hedge
Anticipated debt offering	8 forward starting swaps (30-year)	$ 200	6/15/2016	3.06%	Cash flow hedge
Anticipated debt offering	8 forward starting swaps (30-year)	$ 200	6/15/2017	3.14%	Cash flow hedge
Anticipated debt offering	8 forward starting swaps (30-year)	$ 200	6/15/2018	3.20%	Cash flow hedge

Additionally, we entered into eight forward starting interest rate swaps in January 2015 with an aggregate notional amount of $200 million, locking in a weighted average interest rate of 2.83% for an anticipated debt offering. The expected termination date on these swaps is June 14, 2019.

The following table summarizes activity related to terminated interest rate derivatives (all of which were designated as cash flow hedges) for the years ended December 31, 2014, 2013 and 2012 (notional amounts and cash received/(paid) in millions):

Hedged Transaction	Number and Types of Derivatives Terminated	Notional Amount	Cash Received/(Paid)	Average Rate Locked
April 2014 senior note issuance	5 treasury lock agreements	$ 250	$ (7)	3.62%
August 2013 senior note issuance (1)	5 forward starting swaps (30-year)	$ 125	$ 11	3.39%
December 2012 senior note issuance	6 forward starting swaps (30-year)	$ 250	$ (89)	4.24%
March 2012 senior note issuance (2)	4 forward starting swaps (10-year)	$ 200	$ (24)	3.46%

(1) A gain of approximately $3 million was immediately recognized in interest expense attributable to the ineffective portion of these swaps upon termination.

(2) A loss of approximately $1 million was immediately recognized in interest expense attributable to the ineffective portion of these swaps upon termination.

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use foreign currency derivatives to minimize the risk of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts and forwards.

As of December 31, 2014, our outstanding foreign currency derivatives include derivatives we use to (i) hedge currency exchange risk associated with USD-denominated commodity purchases and sales in Canada and (ii) hedge currency exchange risk created by the use of USD-denominated commodity derivatives to hedge commodity price risk associated with CAD-denominated commodity purchases and sales.

Table of Contents

The following table summarizes our open forward exchange contracts as of December 31, 2014 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD
Forward exchange contracts that exchange CAD for USD:				
	2015	$ 460	$ 535	$1.00 - $1.16
Forward exchange contracts that exchange USD for CAD:				
	2015	$ 345	$ 387	$1.00 - $1.12

Summary of Financial Impact

We record all open derivatives on the balance sheet as either assets or liabilities measured at fair value. Changes in the fair value of derivatives are recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives that qualify as cash flow hedges, changes in fair value of the effective portion of the hedges are deferred in AOCI and recognized in earnings in the periods during which the underlying physical transactions are recognized in earnings. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that are not highly effective in offsetting changes in cash flows of the hedged items are recognized in earnings each period. Cash settlements associated with our derivative activities are reflected as cash flows from operating activities in our Consolidated Statements of Cash Flows.

A summary of the impact of our derivative activities recognized in earnings for the years ended December 31, 2014, 2013 and 2012 is as follows (in millions):

	Year Ended December 31, 2014			
	Derivatives in Hedging Relationships			
Location of gain/(loss)	**Gain/(loss) reclassified from AOCI into income (1) (2)**	**Other gain/(loss) recognized in income**	**Derivatives Not Designated as a Hedge**	**Total**
Commodity Derivatives				
Supply and Logistics segment revenues	$ (1)	$	$ 206	$ 205
Field operating costs			(21)	(21)
Interest Rate Derivatives				
Interest expense	(5)			(5)
Foreign Currency Derivatives				
Supply and Logistics segment revenues			(28)	(28)
Other income/(expense), net	2			2
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (4)	$	$ 157	$ 153

Table of Contents

	Year Ended December 31, 2013			
	Derivatives in Hedging Relationships			
Location of gain/(loss)	Gain/(loss) reclassified from AOCI into income (1)	Other gain/(loss) recognized in income	Derivatives Not Designated as a Hedge	Total
Commodity Derivatives				
Supply and Logistics segment revenues	$ 78	$ (1)	$ (116)	$ (39)
Facilities segment revenues	(10)	(1)		(11)
Field operating costs			8	8
Interest Rate Derivatives				
Interest expense	(7)	3		(4)
Foreign Currency Derivatives				
Other income/(expense), net	5			5
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ 66	$ 1	$ (108)	$ (41)

	Year Ended December 31, 2012			
	Derivatives in Hedging Relationships			
Location of gain/(loss)	Gain/(loss) reclassified from AOCI into income (1)	Other gain/(loss) recognized in income	Derivatives Not Designated as a Hedge	Total
Commodity Derivatives				
Supply and Logistics segment revenues	$ 12	$	$ 60	$ 72
Facilities segment revenues	3	(1)	1	3
Purchases and related costs	45		1	46
Field operating costs			1	1
Interest Rate Derivatives				
Interest expense	(4)	1		(3)
Foreign Currency Derivatives				
Supply and Logistics segment revenues			(1)	(1)
Other income/(expense), net	6			6
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ 62	$	$ 62	$ 124

Table of Contents

---

(1) During the years ended December 31, 2014 and 2012, all of our hedged transactions were probable of occurring. During the year ended December 31, 2013, we reclassified gains of $3 million and losses of $1 million from AOCI to Supply and Logistics segment revenues and Facilities segment revenues, respectively, as a result of anticipated hedged transactions that were probable of not occurring.

(2) During the year ended December 31, 2014 we reclassified gains of $7 million from AOCI to Supply and Logistics segment revenues associated with inventory valuation adjustments on the related hedged inventory.

The following table summarizes the derivative assets and liabilities on our Consolidated Balance Sheet on a gross basis as of December 31, 2014 (in millions):

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location		**Fair Value**	**Balance Sheet Location**		**Fair Value**
Derivatives designated as hedging instruments:						
Commodity derivatives	Other current assets	$	23	Other current assets	$	(12)
	Other long-term assets		8	Other long-term assets		(1)
Interest rate derivatives				Other current liabilities		(44)
				Other long-term liabilities		(26)
Total derivatives designated as hedging instruments		$	31		$	(83)
Derivatives not designated as hedging instruments:						
Commodity derivatives	Other current assets	$	439	Other current assets	$	(246)
	Other long-term assets		23	Other long-term assets		(3)
				Other current liabilities		(35)
				Other long-term liabilities		(5)
Foreign currency derivatives				Other current liabilities		(12)
Total derivatives not designated as hedging instruments		$	462		$	(301)
Total derivatives		$	493		$	(384)

The following table summarizes the derivative assets and liabilities on our Consolidated Balance Sheet on a gross basis as of December 31, 2013 (in millions):

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location		**Fair Value**	**Balance Sheet Location**		**Fair Value**

Derivatives designated as hedging instruments:						
Commodity derivatives	Other current assets	$	36	Other current assets	$	(24)
	Other long-term assets		5			
Interest rate derivatives	Other long-term assets		26			
Total derivatives designated as hedging instruments		$	67		$	(24)
Derivatives not designated as hedging instruments:						
Commodity derivatives	Other current assets	$	60	Other current assets	$	(117)
	Other long-term assets		5	Other long-term assets		(6)
	Other current liabilities		1	Other current liabilities		(5)
				Other long-term liabilities		(1)
Foreign currency derivatives				Other current liabilities		(4)
Total derivatives not designated as hedging instruments		$	66		$	(133)
Total derivatives		$	133		$	(157)

Our derivative transactions are governed through ISDA (International Swaps and Derivatives Association) master agreements and clearing brokerage agreements. These agreements include stipulations regarding the right of set off in the event that we or our

Table of Contents

counterparty default on our performance obligations. If a default were to occur, both parties have the right to net amounts payable and receivable into a single net settlement between parties.

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting arrangement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through clearing brokerage accounts and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of December 31, 2014, we had a net broker payable of $133 million (consisting of initial margin of $126 million reduced by $259 million of variation margin that had been returned to us). As of December 31, 2013, we had a net broker receivable of $161 million (consisting of initial margin of $85 million increased by $76 million of variation margin that had been posted by us).

The following tables present information about derivatives and financial assets and liabilities that are subject to offsetting, including enforceable master netting arrangements as of the dates indicated (in millions):

	December 31, 2014		December 31, 2013	
	Derivative Asset Positions	**Derivative Liability Positions**	**Derivative Asset Positions**	**Derivative Liability Positions**
Netting Adjustments:				
Gross position - asset/(liability)	$ 493	$ (384)	$ 133	$ (157)
Netting adjustment	(262)	262	(148)	148
Cash collateral paid/(received)	(133)		161	
Net position - asset/(liability)	$ 98	$ (122)	$ 146	$ (9)
Balance Sheet Location After Netting Adjustments:				
Other current assets	$ 71	$	$ 116	$
Other long-term assets	27		30	
Other current liabilities		(91)		(8)
Other long-term liabilities		(31)		(1)
	$ 98	$ (122)	$ 146	$ (9)

As of December 31, 2014, there was a net loss of $159 million deferred in AOCI including tax effects. The deferred net loss recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the earnings recognition of the underlying hedged commodity transaction or (ii) interest expense accruals associated with underlying debt instruments. Of the total net loss deferred in AOCI at December 31, 2014, we expect to reclassify a net gain of $14 million to earnings in the next twelve months. The remaining deferred loss of $173 million is expected to be reclassified to earnings through 2048. A portion of these amounts are based on market prices as of December 31, 2014; thus, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

The net deferred gain/(loss), including tax effects, recognized in AOCI for derivatives for the three years ended December 31, 2014 are as follows (in millions):

Year Ended December 31,

	2014	2013	2012
Commodity derivatives, net	$ 15	$ 37	$ 56
Interest rate derivatives, net	(103)	72	(12)
Foreign currency derivatives, net	2		
Total	$ (86)	$ 109	$ 44

At December 31, 2014 and December 31, 2013, 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. Although we may be required to post margin on our cleared derivatives as described above, we do not require our non-cleared derivative counterparties to post collateral with us.

Table of Contents

Recurring Fair Value Measurements

Derivative Financial Assets and Liabilities

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2014 and December 31, 2013 (in millions):

	Fair Value as of December 31, 2014				Fair Value as of December 31, 2013			
Recurring Fair Value Measures (1)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivatives	$ (85)	$ 261	$ 15	$ 191	$ 16	$ (59)	$ (3)	$ (46)
Interest rate derivatives		(70)		(70)		26		26
Foreign currency derivatives		(12)		(12)		(4)		(4)
Total net derivative asset/(liability)	$ (85)	$ 179	$ 15	$ 109	$ 16	$ (37)	$ (3)	$ (24)

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

Level 1

Level 1 of the fair value hierarchy includes exchange-traded commodity derivatives such as futures and options. The fair value of exchange-traded commodity derivatives is based on unadjusted quoted prices in active markets.

Level 2

Level 2 of the fair value hierarchy includes exchange-cleared commodity derivatives and over-the-counter commodity, interest rate and foreign currency derivatives that are traded in active markets. In addition, it includes certain physical commodity contracts. The fair value of these derivatives is based on broker price quotations which are corroborated with market observable inputs.

Level 3

Level 3 of the fair value hierarchy includes certain physical commodity contracts. The fair value of our Level 3 physical commodity contracts is based on a valuation model utilizing broker-quoted forward commodity prices, and timing estimates, which involve management judgment. The significant unobservable inputs used in the fair value measurement of our Level 3 derivatives are forward prices obtained from brokers. A significant increase or decrease in these forward prices could result in a material change in fair value to our Level 3 derivatives.

Rollforward of Level 3 Net Asset/(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, 2014		2013	
Beginning Balance	$	(3)	$	4
Total gains/(losses) for the period:				
Included in earnings (1)				(1)
Included in other comprehensive income				
Settlements		3		(3)
Derivatives entered into during the period		15		(3)
Transfers out of Level 3				
Ending Balance	$	15	$	(3)
Change in unrealized gains/(losses) included in earnings relating to Level 3 derivatives still held at the end of the periods	$	15	$	(4)

(1) We reported unrealized gains and losses associated with Level 3 commodity derivatives in our Consolidated Statements of Operations as Supply and Logistics segment revenues.

Table of Contents

Note 13 Income Taxes

Income tax expense is estimated using the tax rate in effect or to be in effect during the relevant periods in the jurisdictions in which we operate. Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes and are stated at enacted tax rates expected to be in effect when taxes are actually paid or recovered. To the extent we do not consider it more likely than not that a deferred tax asset will be recovered, a valuation allowance is established. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. We review contingent tax liabilities for estimated exposures on a more likely than not standard related to our current tax positions.

Pursuant to FASB guidance related to accounting for uncertainty in income taxes, 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, 2014 and 2013, we had not recognized any material amounts in connection with uncertainty in income taxes.

U.S. Federal and State Taxes

As an MLP, we are not subject to U.S. federal income taxes; rather the tax effect of our operations is passed through to our unitholders. Although we are subject to state income taxes in some states, the impact to the years ended December 31, 2014, 2013, and 2012 was immaterial.

Canadian Federal and Provincial Taxes

All of our Canadian operations are conducted within entities that are treated as corporations for Canadian tax purposes (flow through for U.S. tax purposes) and that are subject to Canadian federal and provincial taxes. Additionally, payments of interest and dividends from our Canadian entities to other Plains entities are subject to Canadian withholding tax that is treated as income tax expense.

Tax Components

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

	Year Ended December 31,		
	2014	**2013**	**2012**
Current tax expense:			
State income tax	$ 1	$ 1	$ 2
Canadian federal and provincial income tax	70	99	51

Total current tax expense	$	71	$	100	$	53
Deferred tax (benefit)/expense:						
Canadian federal and provincial income tax	$	100	$	(1)	$	1
Total deferred tax (benefit)/expense	$	100	$	(1)	$	1
Total income tax expense	$	171	$	99	$	54

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

Table of Contents

	Year Ended December 31, 2014		2013		2012	
Income before tax	$	1,557	$	1,490	$	1,181
Partnership earnings not subject to current Canadian tax		(976)		(1,187)		(1,046)
	$	581	$	303	$	135
Canadian federal and provincial corporate tax rate		25%		25%		25%
Income tax at statutory rate	$	145	$	76	$	34
Canadian withholding tax	$	16	$	19	$	18
Canadian permanent differences and rate changes		9		3		
State income tax		1		1		2
Total income tax expense	$	171	$	99	$	54

Deferred tax assets and liabilities are aggregated by the applicable tax paying entity and jurisdiction and result from the following (in millions):

	December 31, 2014		2013	
Deferred tax assets:				
Book accruals in excess of current tax deductions	$	29	$	41
Net operating losses		2		
Derivative instruments				15
Total deferred tax assets		31		56
Deferred tax liabilities:				
Derivative instruments		(71)		
Property and equipment in excess of tax values		(322)		(332)
Other		(49)		(66)
Total deferred tax liabilities		(442)		(398)
Net deferred tax assets / (liabilities)	$	(411)	$	(342)
Balance sheet classification of deferred tax assets / (liabilities):				
Other, net	$	2	$	
Other current liabilities		(64)		
Other long-term liabilities and deferred credits		(349)		(342)
	$	(411)	$	(342)

As of December 31, 2014, we had foreign net operating loss carryforwards of $8 million, which will expire in 2034.

Generally, tax returns for our Canadian entities are open to audit from 2008 through 2014. Our U.S. and state tax years are generally open to examination from 2011 to 2014.

Note 14 Major Customers and Concentration of Credit Risk

Marathon Petroleum Corporation and its subsidiaries accounted for approximately 17%, 15% and 16% of our revenues for the years ended December 31, 2014, 2013 and 2012, respectively. ExxonMobil Corporation and its subsidiaries accounted for approximately 15% of our revenues for the year ended December 31, 2014 and approximately 13% of our revenues for each of the years ended December 31, 2013 and 2012. Phillips 66 and its subsidiaries accounted for approximately 11% of our revenues for the year ended December 31, 2013. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2014. The majority of revenues from these customers pertain to our supply and logistics operations. The sales to these customers occur at multiple locations and 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 and, to a lesser extent, purchasers of NGL and natural gas storage. 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 15 Related Party Transactions

Reimbursement of Expenses of Our General Partner and its Affiliates

We do not pay our general partner a management fee, but we do reimburse our general partner for all direct and indirect costs of services provided to us or incurred on our behalf, including the costs of employee, officer and director compensation and benefits allocable to us as well as all other expenses necessary or appropriate to the conduct of our business (other than expenses related to grants of AAP Management 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, 2014, 2013 and 2012 were $598 million, $567 million and $535 million, respectively.

Transactions with Oxy

On November 14, 2014, we purchased Oxy s 50% interest in BridgeTex. See Note 8 for further discussion. Also on November 14, 2014, Oxy exchanged a portion of its interest in our general partner for Class A shares of PAGP and immediately sold such shares through a secondary public offering completed by PAGP. As of December 31, 2014, Oxy owned approximately 13.2% of the limited partner interests in our general partner and had a representative on the board of directors of GP LLC.

During the three years ended December 31, 2014, we recognized sales and transportation revenues and purchased petroleum products from Oxy. These transactions were conducted at posted tariff rates or prices that we believe approximate market. See detail below (in millions):

	Year Ended December 31,		
	2014	2013	2012
Revenues	$ 1,212	$ 1,309	$ 1,636
Purchases and related costs	$ 925	$ 863	$ 557

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

	December 31,	
	2014	2013
Trade accounts receivable and other receivables	$ 489	$ 133
Accounts payable	$ 441	$ 181

Transactions with Equity Method Investees

We also have transactions with companies in which we hold an investment accounted for under the equity method of accounting (see Note 8 for information related to these investments). We recorded revenues of $3 million, $33 million and $18 million during the years ended December 31, 2014, 2013 and 2012, respectively. The revenues for the years ended December 31, 2013 and 2012 were primarily associated with sales of crude oil to Eagle Ford Pipeline LLC for its linefill requirements. These sales did not result in any gain for us. During the three years ended December 31, 2014, we utilized transportation services and purchased petroleum products provided by these companies. Costs related to these services totaled $75 million, $79 million and $42 million for the years ended December 31, 2014, 2013 and 2012, respectively. These transactions were conducted at posted tariff rates or contracted rates or prices that we believe approximate market. Receivables from our equity method investees totaled less than $1 million at December 31, 2014 and $2 million at December 31, 2013. Accounts payable to our equity method investees were $6 million at both December 31, 2014 and December 31, 2013.

In 2014, we sold land to Eagle Ford Pipeline LLC for proceeds of $25 million. Such proceeds are included in Proceeds from sales of assets on our Consolidated Statement of Cash Flows. We did not recognize any gain in connection with this transaction.

Table of Contents

Note 16 Equity-Indexed Compensation Plans

PAA Long-Term Incentive Plan Awards

Plains All American 2013 Long-Term Incentive Plan. In November 2013, our common unitholders approved the Plains All American 2013 Long-Term Incentive Plan (the PAA 2013 LTIP), which consolidated our three previous long-term incentive plans (the Plains All American GP LLC 1998 Long-Term Incentive Plan, as amended, the Plains All American 2005 Long-Term Incentive Plan, as amended, and the Plains All American PPX Successor Long-Term Incentive Plan, as amended) into a single plan. The PAA 2013 LTIP authorizes the issuance of an aggregate of approximately 13.1 million PAA common units deliverable upon vesting. Although other types of awards are contemplated under the PAA 2013 LTIP, currently outstanding awards are limited to phantom units, which mature into the right to receive common units of PAA (or cash equivalent) upon vesting. Some awards also include DERs, which, subject to applicable vesting criteria, entitle the grantee to a cash payment equal to the cash distribution paid on an outstanding PAA common unit.

Plains All American PNG Successor Long-Term Incentive Plan. In conjunction with the PNG Merger on December 31, 2013, our general partner adopted and assumed the PAA Natural Gas Storage, L.P. 2010 Long-Term Incentive Plan (the PNG 2010 LTIP) and changed the plan name to the Plains All American PNG Successor Long-Term Incentive Plan (the PNG Successor LTIP). Additionally, as a result of the PNG Merger, outstanding awards of PNG phantom units issued under the PNG 2010 LTIP were converted into comparable awards of phantom units representing the right to receive PAA common units by applying the Merger Exchange Ratio to each outstanding phantom unit and rounding down to the nearest PAA phantom unit for any fractions. See Note 10 for further discussion of the PNG Merger. The PNG Successor LTIP authorizes the issuance of an aggregate of 1.3 million PAA common units deliverable upon vesting. Although other types of awards are contemplated under the PNG Successor LTIP, currently outstanding awards are limited to phantom units, which mature into the right to receive common units of PAA (or cash equivalent) upon vesting. Some awards also include DERs, which, subject to applicable vesting criteria, entitle the grantee to a cash payment equal to the cash distribution paid on an outstanding PAA common unit.

Plains All American GP LLC 2006 Long-Term Incentive Tracking Unit Plan. Our general partner has adopted the Plains All American GP LLC 2006 Long-Term Incentive Tracking Unit Plan (the 2006 Plan) for non-officer employees. The 2006 Plan authorizes the grant of approximately 4.2 million tracking units which, upon vesting, represent the right to receive a cash payment in an amount based upon the market value of a PAA 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 PAA 2013 LTIP, the PNG Successor LTIP or the 2006 Plan.

At December 31, 2014, the following LTIP awards, denominated in PAA units, were outstanding (units in millions):

PAA LTIP Units Outstanding (1) (2)	PAA Distribution Required (3)	Estimated Unit Vesting Date				
		2015	2016	2017	2018	Thereafter
7.3	$2.075-$3.200	2.1	2.1	1.8	1.2	0.1

(1) Approximately 3.5 million of the 7.3 million outstanding PAA LTIP awards also include DERs, of which 3.2 million had vested as of December 31, 2014.

(2) LTIP units outstanding do not include AAP Management Units.

(3) These LTIP awards have performance conditions requiring the attainment of an annualized PAA distribution of between $2.075 and $3.20 and vest upon the later of a certain date or the attainment of such levels. If the performance conditions are not attained while the grantee remains employed by us, or the grantee does not meet employment requirements, these awards will be forfeited. For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

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

Table of Contents

of any distributions that are estimated to occur on the underlying units over the vesting period that will not be received by the award recipient. This fair value is recognized as compensation expense over the service period.

Our LTIP awards typically contain performance conditions based on the attainment of certain annualized distribution levels and vest upon the later of a certain date or the attainment of such levels. For awards with performance conditions (such as distribution targets), expense is accrued over the service period only if the performance condition is considered probable of occurring. When awards with performance conditions that were previously considered improbable become probable, we incur additional expense in the period that the probability assessment changes. This is necessary to bring the accrued obligation associated with these awards up to the level it would be if we had been accruing for these awards since the grant date. DER awards typically contain performance conditions based on the attainment of certain annualized distribution levels and become earned upon the attainment of such levels. The DERs terminate with the vesting or forfeiture of the underlying LTIP award. For liability-classified awards, we recognize DER payments in the period the payment is earned as compensation expense. For equity-classified awards, we recognize DER payments in the period it is paid as a reduction of partners capital.

Our accrued liability at December 31, 2014 related to all outstanding liability-classified LTIP awards and DERs was $101 million, of which $57 million was classified as short-term and $44 million was classified as long-term. These short- and long-term accrued LTIP liabilities are reflected in Accounts payable and accrued liabilities and Other long-term liabilities and deferred credits, respectively, on our Consolidated Balance Sheet. These liabilities include accruals associated with our assessments that an annualized distribution of $2.90 was probable of occurring. At December 31, 2013, the accrued liability was $98 million, of which $43 million was classified as short-term and $55 million was classified as long-term.

Activity for LTIP awards under our equity-indexed compensation plans denominated in PAA and PNG units is summarized in the following table (units in millions):

	PAA Units (1) (3)			**PNG Units (2) (4)**		
	Units		**Weighted Average Grant Date Fair Value per Unit**	**Units**		**Weighted Average Grant Date Fair Value per Unit**
Outstanding at December 31, 2011	8.0	$	21.77	0.8	$	20.55
Granted	1.5	$	33.90	0.1	$	15.33
Vested	(3.2)	$	19.82		$	23.64
Cancelled or forfeited	(0.3)	$	29.36		$	
Outstanding at December 31, 2012	6.0	$	25.55	0.9	$	17.49
Granted	4.1	$	47.60	0.4	$	17.51
Vested	(1.8)	$	24.79		$	18.88
Cancelled or forfeited (5)	(0.3)	$	36.70	(0.3)	$	21.62
Conversion of PNG unit-denominated awards into PAA unit-denominated awards (6)	0.4	$	40.54	(1.0)	$	16.41
Outstanding at December 31, 2013	8.4	$	36.97		$	
Granted	1.2	$	47.68			
Vested	(1.9)	$	25.49			
Cancelled or forfeited	(0.4)	$	40.14			
Outstanding at December 31, 2014	7.3	$	41.21			

(1) Amounts do not include AAP Management Units.

(2) Amounts include PNG Transaction Grants, which are discussed further below.

(3) Approximately 0.6 million, 0.5 million and 1.0 million PAA common units were issued net of tax withholding of approximately 0.3 million, 0.3 million and 0.5 million units in 2014, 2013 and 2012, respectively, in connection with the settlement of vested awards. The remaining PAA awards (approximately 1.0 million, 1.0 million and 1.7 million units) that vested during 2014, 2013 and 2012, respectively, were settled in cash.

(4) Less than 0.1 million PNG units vested during each of the years ended December 31, 2013 and 2012.

(5) As a result of the PNG Merger on December 31, 2013, approximately 0.3 million outstanding PNG Transaction Grants were cancelled.

Table of Contents

(6) As a result of the PNG Merger on December 31, 2013, outstanding awards of PNG phantom units were converted into comparable awards of PAA phantom units representing the right to receive PAA common units by applying the Merger Exchange Ratio to each outstanding PNG phantom unit and rounding down to the nearest PAA phantom unit for any fractions.

PNG Transaction Grants

In connection with the IPO of PNG in 2010, we created a plan based on PNG equity. In September 2010, we entered into agreements with certain of our officers, pursuant to which these officers acquired, in equal proportion, phantom common units, phantom series A subordinated units, and phantom series B subordinated units representing a portion of the limited partner interest of PNG issued to us in connection with PNG s IPO. The phantom common units vested in equal one-half increments in May 2011 and May 2012. The unvested portion of these grants were surrendered on December 31, 2013 in connection with the closing of the PNG Merger.

AAP Management Units

In August 2007, the owners of our general partner authorized the issuance of AAP Management Units in order to provide additional performance incentives and encourage retention for certain members of our senior management. AAP Management Units become earned in various increments upon the achievement of annualized PAA distribution levels of between $1.75 and $3.10 (or in some cases, within 180 days thereafter). As of December 31, 2014, 1.3 million AAP Management Units had not yet become earned; however, these unearned AAP Management Units will become earned in various increments 180 days after the achievement of annualized PAA distribution levels of between $2.55 and $3.10. When earned, the AAP Management Units are entitled to participate in distributions paid by our general partner in excess of $11 million (as adjusted for debt service costs and excluding special distributions funded by debt) per quarter. Up to approximately 52.1 million AAP Management Units are authorized for issuance. Assuming all 52.1 million AAP Management Units were granted and earned, the maximum participation would be approximately 8% of our general partner s distribution in excess of $11 million (as adjusted) each quarter.

The following is a summary of activity of AAP Management Units for the periods indicated (in millions):

	Reserved for Future Grants	Outstanding	Outstanding Units Earned	Grant Date Fair Value of Outstanding AAP Management Units (1)
Balance as of December 31, 2012	4.7	47.4	34.0	$ 44
Granted	(1.2)	1.2		7
Earned	N/A	N/A	13.0	N/A
Balance as of December 31, 2013	3.5	48.6	47.0	$ 51
Granted	(0.5)	0.5		13
Earned	N/A	N/A	0.8	N/A
Balance as of December 31, 2014	3.0	49.1	47.8	$ 64

(1) Of the $64 million grant date fair value, $55 million had been recognized through December 31, 2014 on a cumulative basis. Of this amount, $7 million, $5 million and $6 million was recognized as expense during the years ended December 31, 2014, 2013 and 2012, respectively.

The entire economic burden of the AAP Management Units, which are equity classified, is borne solely by AAP and does not impact our cash or units outstanding. However, because the intent of the AAP Management Units is to provide a performance incentive and encourage retention for certain members of our senior management, we recognize the grant date fair value of the AAP Management 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 on our Consolidated Financial Statements.

Table of Contents

Other Consolidated Equity-Indexed Compensation Plan Information

We refer to all of the LTIPs and AAP Management Units collectively as the Equity-indexed compensation plans. The table below summarizes the expense recognized and the value of vested LTIPs (settled both in common units and cash) under our equity-indexed compensation plans and includes both liability-classified and equity-classified awards (in millions):

	Year Ended December 31, 2014	2013	2012
Equity-indexed compensation expense	$ 98	$ 116	$ 101
LTIP unit-settled vestings (1)	$ 53	$ 48	$ 62
LTIP cash-settled vestings	$ 53	$ 61	$ 66
DER cash payments	$ 8	$ 8	$ 7

(1) For the years ended December 31, 2013 and 2012, less than $1 million and $1 million, respectively, relates to unit vestings which were settled with PNG common units.

Based on the December 31, 2014 fair value measurement and probability assessment regarding future distributions, we expect to recognize $144 million of additional expense over the life of our outstanding awards related to the remaining unrecognized fair value. Actual amounts may differ materially as a result of a change in the market price of our units and/or probability assessments regarding future distributions. We estimate that the remaining fair value will be recognized in expense as shown below (in millions):

Year	Equity-Indexed Compensation Plan Fair Value Amortization (1) (2)
2015	$ 70
2016	46
2017	21
2018	6
2019	1
Thereafter	
Total	$ 144

(1) Amounts do not include fair value associated with awards containing performance conditions that are not considered to be probable of occurring at December 31, 2014.

(2) Includes unamortized fair value associated with AAP Management Units.

Note 17 Commitments and Contingencies

Commitments

Lease expense for 2014, 2013 and 2012 was $145 million, $132 million and $102 million, respectively. We have commitments, some of which are leases, related to real property, equipment and operating facilities. We also incur costs associated with leased land, rights-of-way, permits and regulatory fees. Future non-cancelable commitments related to these items at December 31, 2014, are summarized below (in millions):

	2015	2016	2017	2018	2019	Thereafter	Total
Leases (1)	$ 162	$ 151	$ 127	$ 102	$ 78	$ 373	$ 993
Other commitments (2)	62	62	49	38	27	90	328
Total	$ 224	$ 213	$ 176	$ 140	$ 105	$ 463	$ 1,321

(1) Includes capital and operating leases as defined by FASB guidance.

(2) Primarily includes third-party storage and transportation agreements and pipeline throughput agreements.

Table of Contents

Litigation

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

Environmental

General. Although we believe that our efforts to enhance our leak prevention and detection capabilities have produced positive results, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline, rail and storage operations. These releases can result from unpredictable man-made or natural forces and may reach surface water bodies, groundwater aquifers or other sensitive environments. Whether current or past, damages and liabilities associated with any such releases from our assets may substantially affect our business.

We record environmental liabilities when environmental assessments and/or remedial efforts are probable and the amounts can be reasonably estimated. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We do not discount our environmental remediation liabilities to present value. We also record environmental liabilities assumed in business combinations based on the estimated fair value of the environmental obligations caused by past operations of the acquired company. We 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.

Environmental expenditures that pertain to current operations or to future revenues are expensed or capitalized consistent with our capitalization policy for property and equipment. Expenditures that result from the remediation of an existing condition caused by past operations and that do not contribute to current or future profitability are expensed.

At December 31, 2014, our estimated undiscounted reserve for environmental liabilities totaled $82 million, of which $13 million was classified as short-term and $69 million was classified as long-term. At December 31, 2013, our estimated undiscounted reserve for environmental liabilities totaled $93 million, of which $11 million was classified as short-term and $82 million was classified as long-term. The short- and long-term environmental liabilities referenced above are reflected in Accounts payable and accrued liabilities and Other long-term liabilities and deferred credits, respectively, on our Consolidated Balance Sheets. At December 31, 2014 and 2013, we had recorded receivables totaling $8 million and $10 million, respectively, for amounts probable of recovery under insurance and from third parties under indemnification agreements, which are predominantly reflected in Trade accounts receivable and other receivables, net on our Consolidated Balance Sheets.

In some cases, the actual cash expenditures may not occur for three years or longer. Our estimates used in these reserves are based on information currently available to us and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional liabilities. 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.

Bay Springs Pipeline Release. During February 2013, we experienced a crude oil release of approximately 120 barrels on a portion of one of our pipelines near Bay Springs, Mississippi. Most of the released crude oil was contained within our pipeline right of way, but some of the released crude oil entered a nearby waterway where it was contained with booms. The EPA has issued an administrative order requiring us to take various actions in response to the release, including remediation, reporting and other actions. We have satisfied the requirements of the administrative order; however, we may be subjected to a civil penalty. The aggregate cost to clean up and remediate the site was approximately $6 million.

Kemp River Pipeline Releases. During May and June 2013, two separate releases were discovered on our Kemp River pipeline in Northern Alberta, Canada that, in the aggregate, resulted in the release of approximately 700 barrels of condensate and light crude oil. Clean-up and remediation activities are being conducted in cooperation with the applicable regulatory agencies. Final investigation by the Alberta Energy Regulator is not complete. To date, no charges, fines or penalties have been assessed against PMC with respect to these releases; however, it is possible that fines or penalties may be assessed against PMC in the future. We estimate that the aggregate clean-up and remediation costs associated with these releases will be approximately $15 million. Through December 31, 2014, we spent approximately $9 million in connection with clean-up and remediation activities.

National Energy Board Audit. In the third quarter of 2014, the National Energy Board (NEB) of Canada notified PMC that various corrective actions from a 2010 audit had not been completed to the satisfaction of the NEB. The NEB initiated a process to assess PMC s approach to compliance with the NEB s Onshore Pipeline Regulations, which process resulted in the issuance by the NEB of an order on January 15, 2015 that imposed six conditions on PMC designed to enhance PMC s ability to operate its pipelines in a manner that protects the public and the environment. The conditions include the filing of certain safety critical tasks, controls and programs with the NEB, external audits of certain PMC programs and systems, and periodic update meetings with NEB staff regarding the status and progress of corrective actions. In early February 2015, the NEB imposed a penalty on PMC of $76,000 CAD related to these issues. It is possible that additional fines and penalties may be assessed against PMC in the future related to this matter.

Environmental Remediation

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

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

Assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified. We have in the past experienced and in the future likely will experience releases of crude oil into the environment from our pipeline and storage operations. We also may discover environmental impacts from past releases that were previously unidentified.

Insurance

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

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

Our assessment of the current availability of coverage and associated rates for hurricane insurance has led us to the decision to self-insure this risk. This decision does not affect our third-party liability insurance, which still covers hurricane-related liability claims and which we have maintained at our historic coverage levels. In addition, although we believe that we have established adequate reserves to the extent such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

Table of Contents

Note 18 Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total (1)
			(in millions, except per unit data)		
2014					
Revenues	$ 11,684	$ 11,195	$ 11,127	$ 9,459	$ 43,464
Gross margin (2)	$ 582	$ 455	$ 482	$ 597	$ 2,116
Operating income	$ 493	$ 365	$ 404	$ 530	$ 1,791
Net income	$ 385	$ 288	$ 324	$ 390	$ 1,386
Net income attributable to PAA	$ 384	$ 287	$ 323	$ 389	$ 1,384
Basic net income per limited partner unit	$ 0.74	$ 0.45	$ 0.52	$ 0.67	$ 2.39
Diluted net income per limited partner unit	$ 0.73	$ 0.45	$ 0.52	$ 0.67	$ 2.38
Cash distributions per common unit (3)	$ 0.6150	$ 0.6300	$ 0.6450	$ 0.6600	$ 2.5500
2013					
Revenues	$ 10,620	$ 10,295	$ 10,703	$ 10,631	$ 42,249
Gross margin (2)	$ 761	$ 474	$ 375	$ 478	$ 2,087
Operating income	$ 655	$ 383	$ 296	$ 394	$ 1,728
Net income	$ 536	$ 300	$ 237	$ 318	$ 1,391
Net income attributable to PAA	$ 528	$ 292	$ 231	$ 309	$ 1,361
Basic net income per limited partner unit	$ 1.28	$ 0.58	$ 0.38	$ 0.59	$ 2.82
Diluted net income per limited partner unit	$ 1.27	$ 0.57	$ 0.38	$ 0.58	$ 2.80
Cash distributions per common unit (3)	$ 0.5625	$ 0.5750	$ 0.5875	$ 0.6000	$ 2.3250

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

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

(3) Represents cash distributions declared and paid in the period presented.

Note 19 Operating Segments

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. See Revenue Recognition in Note 2 for a summary of the types of products and services from which each segment derives its revenues. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on measures including segment profit and maintenance capital investment. We define segment profit as revenues and equity earnings in unconsolidated entities less (a) purchases and related costs, (b) field operating costs and (c) segment general and administrative expenses. Each of the items above excludes depreciation and amortization.

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

Table of Contents

The following table reflects certain financial data for each segment for the periods indicated (in millions):

	Transportation	Facilities	Supply and Logistics	Total
Year Ended December 31, 2014				
Revenues (1):				
External Customers	$ 774	$ 576	$ 42,114	$ 43,464
Intersegment (2)	881	551	36	1,468
Total revenues of reportable segments	$ 1,655	$ 1,127	$ 42,150	$ 44,932
Equity earnings in unconsolidated entities	$ 108	$	$	$ 108
Segment profit (3) (4)	$ 925	$ 584	$ 782	$ 2,291
Capital expenditures (5)	$ 2,483	$ 582	$ 60	$ 3,125
Maintenance capital	$ 165	$ 52	$ 7	$ 224
As of December 31, 2014				
Total assets	$ 9,637	$ 6,843	$ 5,776	$ 22,256
Investments in unconsolidated entities	$ 1,735	$	$	$ 1,735

	Transportation	Facilities	Supply and Logistics	Total
Year Ended December 31, 2013				
Revenues:				
External Customers	$ 701	$ 856	$ 40,692	$ 42,249
Intersegment (2)	797	521	4	1,322
Total revenues of reportable segments	$ 1,498	$ 1,377	$ 40,696	$ 43,571
Equity earnings in unconsolidated entities	$ 64	$	$	$ 64
Segment profit (3) (4)	$ 729	$ 616	$ 822	$ 2,167
Capital expenditures (5)	$ 1,046	$ 549	$ 46	$ 1,641
Maintenance capital	$ 123	$ 38	$ 15	$ 176
As of December 31, 2013				
Total assets	$ 7,221	$ 6,555	$ 6,584	$ 20,360
Investments in unconsolidated entities	$ 485	$	$	$ 485

	Transportation	Facilities	Supply and Logistics	Total
Year Ended December 31, 2012				
Revenues:				
External Customers	$ 623	$ 736	$ 36,438	$ 37,797
Intersegment (2)	793	362	2	1,157
Total revenues of reportable segments	$ 1,416	$ 1,098	$ 36,440	$ 38,954
Equity earnings in unconsolidated entities	$ 38	$	$	$ 38
Segment profit (3) (4)	$ 710	$ 482	$ 753	$ 1,945
Capital expenditures (5)	$ 1,244	$ 1,724	$ 503	$ 3,471
Maintenance capital	$ 108	$ 49	$ 13	$ 170
As of December 31, 2012				
Total assets	$ 6,423	$ 6,134	$ 6,678	$ 19,235
Investments in unconsolidated entities	$ 343	$	$	$ 343

---

(1) Effective January 1, 2014, our natural gas sales and costs, primarily attributable to the activities performed by our natural gas storage commercial optimization group, are reported in the Supply and Logistics segment. Such items were previously reported in the

Facilities segment.

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

Table of Contents

(3) Supply and Logistics segment profit includes interest expense (related to hedged inventory purchases) of $12 million, $30 million and $12 million for the years ended December 31, 2014, 2013 and 2012, respectively.

(4) The following table reconciles segment profit to net income attributable to PAA (in millions):

	Year Ended December 31, 2014	2013	2012
Segment profit	$ 2,291	$ 2,167	$ 1,945
Depreciation and amortization	(392)	(375)	(482)
Interest expense, net	(340)	(303)	(288)
Other income/(expense), net	(2)	1	6
Income before tax	1,557	1,490	1,181
Income tax expense	(171)	(99)	(54)
Net income	1,386	1,391	1,127
Net income attributable to noncontrolling interests	(2)	(30)	(33)
Net income attributable to PAA	$ 1,384	$ 1,361	$ 1,094

(5) Expenditures for acquisition capital and expansion capital, including investments in unconsolidated entities.

Geographic Data

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

Revenues (1)	Year Ended December 31, 2014	2013	2012
United States	$ 34,860	$ 32,924	$ 29,978
Canada	8,604	9,325	7,819
	$ 43,464	$ 42,249	$ 37,797

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

Long-Lived Assets (1)	December 31, 2014	2013
United States	$ 14,400	$ 11,743
Canada	3,650	3,623
	$ 18,050	$ 15,366

(1) Excludes long-term derivative assets.

Table of Contents

EXHIBIT INDEX

2.1 *	Share Purchase Agreement dated December 1, 2011 by and among Amoco Canada International Holdings B.V. and Plains Midstream Canada ULC (the schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K) (incorporated by reference to Exhibit 2.1 to our Annual Report on Form 10-K for the year ended December 31, 2011).
2.2	Agreement and Plan of Merger dated as of October 21, 2013, by and among Plains All American Pipeline, L.P., PAA Acquisition Company LLC, PAA Natural Gas Storage, L.P. and PNGS GP LLC (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed October 24, 2013).
3.1	Fourth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of May 17, 2012 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed May 23, 2012).
3.2	Amendment No. 1 dated October 1, 2012 to the Fourth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed October 2, 2012).
3.3	Amendment No. 2 dated December 31, 2013 to the Fourth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed December 31, 2013).
3.4	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 our Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.5	Amendment No. 1 dated December 31, 2010 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.9 to our Annual Report on Form 10-K for the year ended December 31, 2010).
3.6	Amendment No. 2 dated January 1, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2010).
3.7	Amendment No. 3 dated June 30, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.7 to our Annual Report on Form 10-K for the year ended December 31, 2013).
3.8	Amendment No. 4 dated January 1, 2013 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P (incorporated by reference to Exhibit 3.8 to our Annual Report on Form 10-K for the year ended December 31, 2013).
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 our Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.10	Amendment No. 1 dated January 1, 2013 to the Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2013).
3.11	Sixth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated October 21, 2013 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K filed October 25, 2013).
3.12	Seventh Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated October 21, 2013 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed October 25, 2013).

Table of Contents

3.13	Amendment No. 1 dated December 31, 2013 to the Seventh Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K filed December 31, 2013).
3.14	Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to our Annual Report on Form 10-K for the year ended December 31, 2006).
3.15	Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to our Annual Report on Form 10-K for the year ended December 31, 2006).
3.16	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to our 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 our Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	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 our Registration Statement on Form S-4, File No. 333-121168).
4.3	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 our Current Report on Form 8-K filed May 31, 2005).
4.4	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 our Current Report on Form 8-K filed May 12, 2006).
4.5	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 our Current Report on Form 8-K filed October 30, 2006).
4.6	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 our Current Report on Form 8-K filed October 30, 2006).
4.7	Thirteenth Supplemental Indenture (Series A and Series B 6.50% 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 our Current Report on Form 8-K filed April 23, 2008).
4.8	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 our Current Report on Form 8-K filed April 20, 2009).
4.9	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 our Current Report on Form 8-K filed September 4, 2009).

Table of Contents

4.10	Eighteenth Supplemental Indenture (3.95% Senior Notes due 2015) dated July 14, 2010 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed July 13, 2010).
4.11	Nineteenth Supplemental Indenture (5.00% Senior Notes due 2021) dated January 14, 2011 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed January 11, 2011).
4.12	Twentieth Supplemental Indenture (3.65% Senior Notes due 2022) dated March 22, 2012 among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed March 26, 2012).
4.13	Twenty-First Supplemental Indenture (5.15% Senior Notes due 2042) dated March 22, 2012 among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed March 26, 2012).
4.14	Twenty-Second Supplemental Indenture (2.85% Senior Notes due 2023) dated December 10, 2012, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed December 12, 2012).
4.15	Twenty-Third Supplemental Indenture (4.30% Senior Notes due 2043) dated December 10, 2012, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed December 12, 2012).
4.16	Twenty-Fourth Supplemental Indenture (3.85% Senior Notes due 2023) dated August 15, 2013, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed August 15, 2013).
4.17	Twenty-Fifth Supplemental Indenture (4.70% Senior Notes due 2044) dated April 23, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed April 29, 2014).
4.18	Twenty-Sixth Supplemental Indenture (3.60% Senior Notes due 2024) dated September 9, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed September 11, 2014).
4.19	Twenty-Seventh Supplemental Indenture (2.60% Senior Notes due 2019) dated December 9, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed December 11, 2014).
4.20	Twenty-Eighth Supplemental Indenture (4.90% Senior Notes due 2045) dated December 9, 2014, by and among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed December 11, 2014).
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 our Registration Statement on Form S-3, File No. 333-162477).
10.1	Credit Agreement dated as of August 19, 2011 among Plains All American Pipeline, L.P., as Borrower; certain subsidiaries of Plains All American Pipeline, L.P. from time to time party thereto, as Designated Borrowers; Bank of America, N.A., as Administrative Agent; and the other Lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed August 25, 2011).
10.2	First Amendment to Credit Agreement dated as of June 27, 2012, among Plains All American Pipeline, L.P. and Plains Midstream Canada ULC, as Borrowers; Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer; Wells Fargo Bank, National Association, as an L/C Issuer; and the other Lenders party thereto (incorporated by

reference to Exhibit 10.2 to our Current Report on Form 8-K filed July 3, 2012).

Table of Contents

10.3	Second Amendment to Credit Agreement dated as of August 16, 2013, among Plains All American Pipeline, L.P. and Plains Midstream Canada ULC, as Borrowers; Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer; Wells Fargo Bank, National Association, as an L/C Issuer; and the other Lenders party thereto (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed August 20, 2013).
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 our 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 our 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 our 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 our 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 our 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 our Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
10.10**	Amended and Restated Employment Agreement between Plains All American GP LLC and Greg L. Armstrong dated as of June 30, 2001 (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.11**	Amended and Restated Employment Agreement between Plains All American GP LLC and Harry N. Pefanis dated as of June 30, 2001 (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.12	Asset Purchase and Sale Agreement dated February 28, 2001 between Murphy Oil Company Ltd. and Plains Marketing Canada, L.P. (incorporated by reference to Exhibit 99.1 to our Current Report on Form 8-K filed May 10, 2001).
10.13	Transportation Agreement dated July 30, 1993, between All American Pipeline Company and Exxon Company, U.S.A. (incorporated by reference to Exhibit 10.9 to our Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).
10.14	Transportation Agreement dated August 2, 1993, among All American Pipeline Company, Texaco Trading and Transportation Inc., Chevron U.S.A. and Sun Operating Limited Partnership (incorporated by reference to Exhibit 10.10 to our Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).
10.15	Contribution, Conveyance and Assumption Agreement among Plains All American Pipeline, L.P. and certain other parties dated as of November 23, 1998 (incorporated by reference to Exhibit 10.3 to our Annual Report on Form 10-K for the year ended December 31, 1998).
10.16	First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to our Annual Report on Form 10-K for the year ended December 31, 1998).

Table of Contents

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 our Annual Report on Form 10-K for the year ended December 31, 1998).
10.18**	PMC (Nova Scotia) Company Bonus Program (incorporated by reference to Exhibit 10.20 to our Annual Report on Form 10-K for the year ended December 31, 2004).
10.19**	Quarterly Bonus Program Summary (incorporated by reference to Exhibit 10.21 to our Annual Report on Form 10-K for the year ended December 31, 2005).
10.20**	Form of LTIP Grant Letter (independent directors) (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K filed February 23, 2005).
10.21**	Form of LTIP Grant Letter (designated directors) (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K filed February 23, 2005).
10.22	Membership Interest Purchase Agreement by and between Sempra Energy Trading Corporation and PAA/Vulcan Gas Storage, LLC dated August 19, 2005 (incorporated by reference to Exhibit 1.2 to our Current Report on Form 8-K filed September 19, 2005).
10.23**	Waiver Agreement dated as of December 23, 2010 between Plains All American GP LLC and Greg L. Armstrong (incorporated by reference to Exhibit 10.31 to our Annual Report on Form 10-K for the year ended December 31, 2010).
10.24**	Waiver Agreement dated as of December 23, 2010 between Plains All American GP LLC and Harry N. Pefanis (incorporated by reference to Exhibit 10.32 to our Annual Report on Form 10-K for the year ended December 31, 2010).
10.25	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 our Current Report on Form 8-K filed August 16, 2005).
10.26	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 our Current Report on Form 8-K filed August 16, 2005).
10.27**	Employment Agreement between Plains All American GP LLC and John P. vonBerg dated December 18, 2001 (incorporated by reference to Exhibit 10.40 to our Annual Report on Form 10-K for the year ended December 31, 2005).
10.28**	Form of LTIP Grant Letter (audit committee members) (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed August 23, 2006).
10.29**	Plains All American PPX Successor Long-Term Incentive Plan (incorporated by reference to Exhibit 10.45 to our Annual Report on Form 10-K for the year ended December 31, 2006).
10.30**	Form of Plains AAP, L.P. Class B Restricted Units Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed January 4, 2008).
10.31	Third Amended and Restated Credit Agreement dated as of August 19, 2011 by and among Plains Marketing, L.P., as Borrower, Plains All American Pipeline, L.P., as Guarantor, Bank of America, N.A., as Administrative Agent, and the other Lenders party thereto (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed August 25, 2011).
10.32	First Amendment to Third Amended and Restated Credit Agreement dated as of June 27, 2012, among Plains Marketing, L.P. and Plains Midstream Canada ULC, as Borrowers; Plains All American Pipeline, L.P., as Guarantor; Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer; and the other Lenders and L/C Issuers party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed July 3, 2012).

10.33	Second Amendment to Third Amended and Restated Credit Agreement dated as of August 16, 2013, among Plains Marketing, L.P. and Plains Midstream Canada ULC, as Borrowers; Plains All American Pipeline, L.P., as Guarantor; Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer; Wells Fargo Bank, National Association, as an L/C Issuer; and the other Lenders and L/C Issuers party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed August 20, 2013).
10.34	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 our Current Report on Form 8-K filed January 4, 2008).
10.35**	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 our Annual Report on Form 10-K for the year ended December 31, 2008).
10.36**	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 our Annual Report on Form 10-K for the year ended December 31, 2008).
10.37**	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 our Annual Report on Form 10-K for the year ended December 31, 2008).
10.38**	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 our Annual Report on Form 10-K for the year ended December 31, 2008).
10.39**	Form of Amendment to LTIP grant letters (executive officers) (incorporated by reference to Exhibit 10.53 to our Annual Report on Form 10-K for the year ended December 31, 2008).
10.40**	Form of Amendment to LTIP grant letters (directors) (incorporated by reference to Exhibit 10.54 to our Annual Report on Form 10-K for the year ended December 31, 2008).
10.41	Contribution Agreement dated as of April 29, 2010 by and among PAA Natural Gas Storage, L.P., PNGS GP LLC, Plains All American Pipeline, L.P., PAA Natural Gas Storage, LLC, PAA/Vulcan Gas Storage, LLC, Plains Marketing, L.P. and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to PNG s Current Report on Form 8-K filed May 4, 2010).
10.42	Omnibus Agreement dated May 5, 2010 by and among Plains All American GP LLC, Plains All American Pipeline, L.P., PNGS GP LLC and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 10.1 to PNG s Current Report on Form 8-K filed May 11, 2010).
10.43**	Form of 2010 LTIP Grant Letters (incorporated by reference to Exhibit 10.58 to our Annual Report on Form 10-K for the year ended December 31, 2010).
10.44**	Director Compensation Summary (incorporated by reference to Exhibit 10.45 to our Annual Report on Form 10-K for the year ended December 31, 2011).
10.45	Administrative Agreement dated October 21, 2013 by and among Plains GP Holdings, L.P., PAA GP Holdings LLC, Plains All American Pipeline, L.P., PAA GP LLC, Plains AAP, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed October 25, 2013).
10.46**	Waiver Agreement dated October 21, 2013 to the Amended and Restated Employment Agreement dated June 30, 2001 of Greg L. Armstrong (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed October 25, 2013).

Table of Contents

10.47**	Waiver Agreement dated October 21, 2013 to the Amended and Restated Employment Agreement dated June 30, 2001 of Harry N. Pefanis (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K filed October 25, 2013).
10.48**	Form of Amendment to the Plains AAP, L.P. Class B Restricted Units Agreement, dated October 18, 2013 (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K filed October 25, 2013).
10.49**	Plains All American 2013 Long-Term Incentive Plan (incorporated by reference to Exhibit A to our Definitive Proxy Statement filed on October 3, 2013).
10.50**	Plains All American PNG Successor Long-Term Incentive Plan (incorporated by reference to Exhibit 4.4 to our Registration Statement on Form S-8 (333-19319) filed December 31, 2013).
10.51**	PAA Natural Gas Storage, L.P. 2010 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to PNG s Current Report on Form 8-K filed May 11, 2010).
10.52**	Form of PAA LTIP Grant Letter for Officers (February 2013) (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2013).
10.53	364-Day Credit Agreement dated January 16, 2015 among Plains All American Pipeline, L.P., as Borrower; Bank of America, N.A., as Administrative Agent; Citibank, N.A., JPMorgan Chase Bank N.A. and Wells Fargo Bank, National Association, as Co-Syndication Agents; DNB Bank ASA, New York Branch and Mizuho Bank, Ltd., as Co-Documentation Agents; the other Lenders party thereto; and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., DNB Markets, Inc., J.P. Morgan Securities LLC, Mizuho Bank, Ltd. and Wells Fargo Securities, LLC, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed January 20, 2015).
12.1	Computation of Ratio of Earnings to Fixed Charges.
21.1	List of Subsidiaries of Plains All American Pipeline, L.P.
23.1	Consent of PricewaterhouseCoopers LLP.
31.1	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350.
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350.
101. INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

---

Filed herewith.

Furnished herewith.

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

** Management compensatory plan or arrangement.