PLAINS GP HOLDINGS LP
Form 10-K
March 12, 2014
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, 2013**

**or**

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

**Commission file number 1-36132**

# PLAINS GP HOLDINGS, L.P.

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Delaware**<br>(State or other jurisdiction of<br>incorporation or organization) | **90-1005472**<br>(I.R.S. Employer<br>Identification No.) |
| **333 Clay Street, Suite 1600, Houston, Texas**<br>(Address of principal executive offices) | **77002**<br>(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 |
|---|---|
| Class A Shares,<br>Representing Limited Partner Interests | 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 o No x

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

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

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

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

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

| | |
|---|---|
| Large Accelerated Filer o | Accelerated Filer o |
| Non-Accelerated Filer x<br>(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

As of June 30, 2013, the last day of the registrant s most recently completed second quarter, the registrant s Class A shares were not publicly traded. The aggregate market value of the Class A shares held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Class A shares outstanding, for this purpose, as if they may be affiliates of the registrant) was approximately $3.6 billion on December 31, 2013, based on a closing price of $26.77 per Class A share as reported on the New York Stock Exchange on such date.

As of March 6, 2014, there were 135,833,637 Class A shares outstanding.

**DOCUMENTS INCORPORATED BY REFERENCE**

**NONE**

Table of Contents

**PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES**

**FORM 10-K 2013 ANNUAL REPORT**

**Table of Contents**


| | | Page |
|---|---|---|
| | **PART I** | 4 |
| Items 1 and 2. | Business and Properties | 4 |
| Item 1A. | Risk Factors | 49 |
| Item 1B. | Unresolved Staff Comments | 70 |
| Item 3. | Legal Proceedings | 70 |
| Item 4. | Mine Safety Disclosures | 72 |
| | **PART II** | 73 |
| Item 5. | Market for Registrant s Shares, Related Shareholder Matters and Issuer Purchases of Equity Securities | 73 |
| Item 6. | Selected Financial Data | 75 |
| Item 7. | Management s Discussion and Analysis of Financial Condition and Results of Operations | 76 |
| Item 7A. | Quantitative and Qualitative Disclosures About Market Risk | 100 |
| Item 8. | Financial Statements and Supplementary Data | 101 |
| Item 9. | Changes in and Disagreements With Accountants on Accounting and Financial Disclosure | 101 |
| Item 9A. | Controls and Procedures | 102 |
| Item 9B. | Other Information | 102 |
| | **PART III** | 103 |
| Item 10. | Directors and Executive Officers of Our General Partner and Corporate Governance | 103 |
| Item 11. | Executive Compensation | 112 |
| Item 12. | Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters | 133 |
| Item 13. | Certain Relationships and Related Transactions, and Director Independence | 138 |
| Item 14. | Principal Accountant Fees and Services | 146 |
| | **PART IV** | 147 |
| Item 15. | Exhibits and Financial Statement Schedules | 147 |

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:

- our ability to pay distributions to our Class A shareholders;
- our expected receipt of, and amounts of, distributions from Plains AAP, L.P.;
- failure to implement or capitalize, or delays in implementing or capitalizing, on planned internal growth projects;
- 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 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 access to capital;
- maintenance of PAA s credit rating and ability to receive open credit from suppliers and trade counterparties;

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

- 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 historical operations;

- the effectiveness of our risk management activities;

- 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 or other factors;

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

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

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

- non-utilization of our assets and facilities;

- the effects of competition;

Table of Contents

- increased costs or lack of availability of insurance;
- fluctuations in the debt and equity markets, including the price of PAA s units at the time of vesting under its long-term incentive plans;
- weather interference with business operations or project construction;
- 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 GP Holdings, L.P. ( PAGP ) is a Delaware limited partnership formed on July 17, 2013 to own an interest in the general partner and incentive distribution rights ( IDRs ) of Plains All American Pipeline, L.P ( PAA ), a publicly traded Delaware limited partnership. Although we were formed as a limited partnership, we have elected to be taxed as a corporation for United States federal income tax purposes. As used in this Form 10-K and unless the context indicates otherwise, the terms Partnership, Plains, PAGP, we, us, our, ours and similar terms refer to GP Holdings, L.P. and its subsidiaries.

**Organizational History**

We completed our initial public offering ( IPO ) in October 2013. Immediately prior to our IPO, certain owners of Plains AAP, L.P. ( AAP ) sold a portion of their interests in AAP to us, resulting in our ownership of a limited partnership interest in AAP. As of December 31, 2013, we owned a 22.1% limited partner interest in AAP, and the remaining limited partner interests in AAP continue to be held by the owners of AAP immediately prior to our IPO (the Legacy Owners ). AAP is a Delaware limited partnership that directly owns all of PAA s incentive distribution rights and indirectly owns the 2% general partner interest in PAA. AAP is the sole member of PAA GP LLC ( PAA GP ), a Delaware limited liability company that directly holds the 2% general partner interest in PAA. Also, through a series of transactions prior to our IPO with our general partner and the owners of Plains All American GP LLC ( GP LLC ), a Delaware limited liability company formed on May 2, 2001, GP LLC s general partner interest in AAP became a non-economic interest, and we became the owner of a 100% managing member interest in GP LLC.

Table of Contents

PAA is a publicly traded master limited partnership that owns and operates midstream energy infrastructure and provides 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. PAA owns 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. On average, PAA handles over 3.5 million barrels per day of crude oil and NGL on its pipelines.

**Partnership Structure and Management**

Our general partner, PAA GP Holdings LLC, manages our operations and activities and is responsible for exercising on our behalf any rights we have as the managing member of GP LLC, including any rights to appoint members to the board of directors of GP LLC. See Item 10. Directors and Executive Officers of our General Partner and Corporate Governance. GP LLC has responsibility for managing the business and affairs of PAA and AAP; however, through our rights as the sole and managing member of GP LLC, we effectively control the business and affairs of AAP and PAA. GP LLC employs all domestic officers and personnel involved in the operation and management of PAA and AAP. PAA s Canadian officers and personnel are employed by Plains Midstream Canada ULC. Our general partner does not receive a management fee or other compensation in connection with its management of our business.

The two charts below show the structure and ownership of PAGP and certain subsidiaries as of December 31, 2013 in both an abridged and more detailed format. The first chart depicts PAGP s legal structure in summary format, while the second chart depicts a more comprehensive view of PAGP s legal structure, including ownership and economic interests and shares and units outstanding.

Table of Contents

**Summarized Partnership Structure**

**(as of December 31, 2013)**

Table of Contents

**Detailed Partnership Structure**

**(as of December 31, 2013)**

Table of Contents

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(1) Incentive Distribution Rights ( IDRs ).

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

(4) Represents the number of Class A units of AAP ( AAP units ) for which the Class B units of AAP (referred to herein as the AAP Management Units ) would be exchangeable, assuming a conversion rate of approximately 0.90 AAP units for each AAP Management Unit as of December 31, 2013. The AAP Management Units are entitled to certain proportionate distributions paid by AAP.

(5) As of December 31, 2013, we owned 22.1% of the membership interests in our general partner, which percentage corresponds to our 22.1% ownership percentage of AAP units (representing a 20.6% economic interest in AAP, including the dilutive effect of the AAP Management Units).

**Our Business**

As of December 31, 2013, our only cash-generating assets consist of 133,833,637 AAP units, which represent a 22.1% limited partner interest in AAP (20.6% economic interest including the dilutive effect of the AAP Management Units). Unless we directly acquire and hold assets or businesses in the future, our cash flows will be generated solely from the cash distributions we receive from AAP. AAP does not own any common units in PAA and currently receives all of its cash flows from distributions on its direct ownership of PAA s IDRs and its indirect ownership of PAA s 2% general partner interest. AAP s ownership of both of these interests entitles it to receive, without duplication:

- 2% of all cash distributed in a quarter until $0.2250 has been distributed in respect of each common unit of PAA for that quarter;
- 15% of all cash distributed in a quarter after $0.2250 has been distributed in respect of each common unit of PAA for that quarter;
- 25% of all cash distributed in a quarter after $0.2475 has been distributed in respect of each common unit of PAA for that quarter; and

- 50% of all cash distributed in a quarter after $0.3375 has been distributed in respect of each common unit of PAA for that quarter.

Such amounts do not take into account temporary and permanent reductions in IDR payments that are currently in place in connection with past PAA acquisition activities or that may be implemented with respect to future activities. The cash distributions AAP receives from PAA are tied to (i) PAA s per unit distribution level and (ii) the number of PAA common units outstanding. An increase in either factor (assuming the other factor remains constant or increases) will generally, absent additional IDR reductions, result in an increase in the amount of cash distributions AAP receives from PAA, a portion of which we, in turn, receive from AAP. Because the IDRs currently participate at the maximum percentage participation rate, any future growth in distributions we receive from AAP will not result from an increase in the percentage participation rate associated with the IDRs.

Accordingly, our primary business objective is to increase our cash available for distribution to our Class A shareholders through the execution by PAA of its business strategy. In addition, we may facilitate PAA s growth activities through various means, including, but not limited to, modifying PAA s IDRs, making loans, purchasing equity interests or providing other forms of financial support to PAA.

**PAA s Business Strategy**

PAA s 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, PAA endeavors 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 its transportation, terminalling, storage, processing and fractionation assets with its extensive supply, logistics and distribution expertise. To a lesser extent, PAA also engages in similar activities for natural gas and refined products. We believe PAA s successful execution of this strategy will enable it to generate sustainable earnings and cash flow. PAA intends to manage and grow its business by:

Table of Contents

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

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

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

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

- capitalizing on anticipated intermediate to long-term opportunities for natural gas storage services in North America by owning and operating high-quality natural gas storage facilities and providing its current and future customers reliable, competitive and flexible natural gas storage and related services.

**PAA s Competitive Strengths**

We believe that the following competitive strengths position PAA to successfully execute its principal business strategy:

- *Many of PAA s transportation segment and facilities segment assets are strategically located and operationally flexible.* The majority of PAA s primary transportation segment assets are in crude oil service, are located in well-established oil producing regions and other transportation corridors and are connected, directly or indirectly, with PAA s facilities segment assets located at major trading locations and premium markets that serve as gateways to major North American refinery and distribution markets where PAA has strong business relationships. PAA s assets include pipeline, rail, barge and truck assets, which provide PAA s customers and PAA with significant flexibility and optionality to satisfy demand and balance markets, particularly during a dynamic period of changing product flows.

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

- *PAA s 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 PAA s supply and logistics segment in combination with PAA s risk management strategies provides PAA with a balance that generally affords it the flexibility to maintain a base level of margin in a variety of market conditions (subject to the effects of seasonality). In certain circumstances, PAA is able to realize incremental margins during volatile market conditions.

- *PAA has the evaluation, integration and engineering skill sets and the financial flexibility to continue to pursue acquisition and expansion opportunities.* Over the past sixteen years, PAA has completed and integrated over 80 acquisitions with an aggregate purchase price of approximately $10.5 billion, which figures include over 30 acquisitions totaling approximately $5.2 billion in aggregate purchase price over the last six years. PAA has also implemented internal expansion capital projects totaling over $5.8 billion. In addition, we believe PAA has the resources to finance future strategic expansion and acquisition opportunities. As of December 31, 2013, PAA had over $1.8 billion available under its committed credit facilities, subject to continued covenant compliance.

- *PAA has an experienced management team whose interests are aligned with those of its unitholders.* PAA s executive management team has an average of 29 years industry experience, and an average of 17 years with PAA or its predecessors and affiliates. In addition, through their ownership of common units, indirect interests in PAA s general partner, grants of phantom units and AAP Management Units, PAA s management team has a vested interest in PAA s continued success.

Table of Contents

**Our Financial Strategy**

Our financial strategy is designed to be complementary with PAA s financial and business strategies. Because our only cash-generating assets consist of our partnership interests in AAP, which currently derives all of its cash flows from PAA s distributions, we intend to maintain a level of indebtedness at AAP such that it will not be material in relation to PAA s adjusted EBITDA or other financial metrics used in the evaluation of its business. As of December 31, 2013, AAP had $515 million of debt outstanding under its credit facility. In connection with future PAA equity issuances, we expect AAP may fund any capital contribution required to maintain its indirect 2% general partner interest in PAA with credit facility borrowings. We do not anticipate that additional debt associated with these contributions will be material to PAA s consolidated credit profile, as such equity issuances are typically used to pay down existing debt or fund PAA s growth through acquisitions or organic growth opportunities. We would expect to fund direct acquisitions made by us, if any, with a combination of debt and equity.

**PAA s Financial Strategy**

***Targeted Credit Profile***

We believe that a major factor in PAA s continued success is its ability to maintain a competitive cost of capital and access to the capital markets. In that regard, PAA intends to maintain a credit profile that it believes is consistent with investment grade credit ratings. PAA has targeted a general credit profile with the following attributes:

- an average long-term debt-to-total capitalization ratio of approximately 45% to 50%;
- a long-term debt-to-adjusted EBITDA multiple averaging between 3.5x and 4.0x (Adjusted EBITDA is earnings before interest, taxes, depreciation and amortization, equity-indexed compensation plan charges, gains and losses from derivative activities and other selected items that impact comparability);
- 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. PAA also incurs short-term debt in connection with its 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. PAA does not consider the working capital borrowings associated with these activities to be part of its long-term capital structure. These borrowings are self-liquidating as they are repaid with sales proceeds. PAA also incurs short-term debt to fund New York Mercantile Exchange ( NYMEX ) and IntercontinentalExchange ( ICE ) margin requirements. In certain market conditions, these routine short-term debt levels may increase significantly above baseline levels.

In order for PAA to maintain its targeted credit profile and achieve growth through internal growth projects and acquisitions, PAA intends 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, PAA may be outside the parameters of its targeted credit profile as, in certain cases, these capital expenditures and acquisitions may be financed initially using debt or there may be delays in realizing anticipated synergies from acquisitions or contributions from capital expansion projects to adjusted EBITDA.

Table of Contents

**PAA s Acquisitions**

The acquisition of midstream assets and businesses that are strategic and complementary to PAA s existing operations constitutes an integral component of its 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 such business lines and enable PAA to leverage its assets, knowledge and skill sets.

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

| Acquisition (1) | Date | Description | Approximate Purchase Price (2) |
|---|---|---|---|
| US Development Group Crude Oil Rail Terminals ( USD ) | 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(3) |
| Western Refining, Inc. Pipeline and Storage Assets ( Western ) | Dec-2011 | Multi-product storage facility in Virginia and a crude oil pipeline in southeastern New Mexico | $ 220(4) |
| 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(5) |
| 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(6) |
| PAA Natural Gas Storage, LLC ( PNGS ) | Sep-2009 | Remaining 50% interest in PNGS | $ 215(7) |

(1) Excludes PAA s 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, PAA issued approximately 14.7 million of its common units with a value of approximately $760 million.

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

(3) 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.

(4) Includes two transactions with Western.

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

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

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

*Ongoing Acquisition Activities*. Consistent with its business strategy, PAA is continuously engaged in discussions with potential sellers regarding the possible purchase of assets and operations that are strategic and complementary to PAA s existing operations. In addition, PAA has in the past evaluated and pursued, and intends in the future to evaluate and pursue, other energy-related assets that have characteristics and provide opportunities similar to PAA s existing business lines and enable PAA to leverage its assets, knowledge and skill sets. Such acquisition efforts may involve participation by PAA in processes that have been made public and involve a number of potential buyers, commonly referred to as auction processes, as well as situations in which PAA believes it is the only party or one of a limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets which, if acquired, could have a material effect on PAA s financial condition and results of operations.

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

Table of Contents

**PAA s Organic Growth Projects**

PAA s extensive asset base and its relationships with customers provide it with opportunities for organic growth through the construction of additional assets that are complementary to, and expand or extend, its existing asset base. PAA believes that the diversity and balance of its organic project portfolio (i.e., relatively large number of projects that are small to medium sized and spread across multiple geographic regions) reduces its overall exposure to cost overruns, timing delays and other adverse market developments with respect to a particular project or region. PAA s 2014 capital plan is representative of the diversity and balance of its overall organic project portfolio. The following expansion projects are included in PAA s 2014 capital plan as of February 2014:

| Basin/Region | Project | 2014 Plan Amount (1) ($ in millions) | | Description |
|---|---|---|---|---|
| Permian | Permian Basin Area Projects | $ | 430 | Multiple projects to increase and expand pipeline infrastructure in the Permian Basin, including the construction of three new trunklines and related assets |
| | Cactus Pipeline | | 310 | 310 miles of new pipeline; 250,000 Bbls/d capacity pipeline from the Permian Basin to the Eagle Ford JV Pipeline |
| Eagle Ford | PAA/Enterprise Products Partners Eagle Ford Joint Venture Project | | 60 | Expansion of Eagle Ford JV pipeline capacity to 470,000 barrels per day; construction of additional 2.3 million barrels of storage capacity |
| | Gardendale Fractionator and Stabilizer | | 35 | New NGL fractionator, expansion of existing condensate stabilization facility and related infrastructure enhancements in the Eagle Ford area of South Texas |
| Mid-Continent | Western Oklahoma Extension | | 50 | 95 miles of new pipeline; 75,000 Bbls/d of capacity from Reydon, OK to Orion Station in Major County, OK |
| | Mississippian Lime Pipeline | | 45 | 45 miles of new crude oil pipeline to complement our existing Mississippian Lime pipelines |
| Rockies/Williston | White Cliffs Pipeline Expansion | | 40 | 35.7% interest in 80,000 Bbls/d expansion of capacity through the construction of a new 12-inch diameter pipeline looping the existing pipeline |
| West Coast | Line 63 Reactivation | | 35 | Reactivation of 71 miles of idled pipeline and supporting assets |
| Canada | Fort Saskatchewan Facility Projects / NGL pipeline | | 180 | Development of two new NGL storage caverns and conversion of service of two existing caverns |
| Various | Rail Terminal Projects | | 185 | Includes new rail facilities and expansion projects located at or near Bakersfield, CA; Carr, Co; Van Hook, ND; and Western Canada |
| | Natural Gas Storage | | 25 | Multiple projects |
| | Other Projects | | 305 | |
| | | $ | 1,700 | |

(1) Represents the portion of the total project cost expected to be incurred during the year.

**Global Petroleum Market Overview**

The United States comprises less than 5% of the world s population, generates approximately 14% of the world s petroleum production, and consumes approximately 21% of the world s petroleum production. The following table sets forth projected world supply and demand for petroleum products (including crude oil and NGL) and is derived from the Energy Information Administration s ( EIA ) Annual Energy Outlook 2014 Early Release (see EIA website at *www.eia.doe.gov*):

Table of Contents

| | | Projected (2) | | | |
|---|---|---|---|---|---|
| | 2013 (1) (2) | 2014 | 2015 | 2016 | 2020 |
| | (In millions of barrels per day) | | | | |
| Supply | | | | | |
| OECD **(3)** | | | | | |
| U.S. | 12.3 | 13.1 | 13.7 | 14.2 | 14.2 |
| Other | 11.5 | 11.8 | 12.1 | 11.6 | 11.2 |
| Total OECD | 23.8 | 24.9 | 25.7 | 25.8 | 25.4 |
| Organization of the Petroleum Exporting Countries | 35.8 | 35.7 | 36.0 | 36.7 | 39.6 |
| Other | 30.4 | 30.7 | 30.7 | 31.4 | 33.0 |
| Total World Production **(4)** | 89.9 | 91.3 | 92.5 | 93.8 | 98.0 |

| | | Projected (2) | | | |
|---|---|---|---|---|---|
| | 2013 (1) (2) | 2014 | 2015 | 2016 | 2020 |
| | (In millions of barrels per day) | | | | |
| Demand | | | | | |
| OECD | | | | | |
| U.S. | 18.8 | 18.8 | 19.2 | 19.4 | 19.5 |
| Other | 27.2 | 26.9 | 26.8 | 26.9 | 27.3 |
| Total OECD | 46.1 | 45.6 | 46.1 | 46.3 | 46.8 |
| Other | 44.3 | 45.6 | 46.4 | 47.5 | 51.2 |
| Total World Consumption **(4)** | 90.4 | 91.3 | 92.5 | 93.8 | 98.0 |

| | | | | | |
|---|---|---|---|---|---|
| U.S. Production as % of World Production | 14% | 14% | 15% | 15% | 14% |
| [redacted] | | | | | |
| Net U.S. (Consumption) | (6.5) | (5.7) | (5.5) | (5.2) | (5.3) |

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(1) The 2013 amounts are derived from the EIA s Short-Term Energy Outlook.

(2) Amounts may not recalculate due to rounding.

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

(4) Production and consumption may not equal in every year due to inventory builds or draws.

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

***Crude Oil Market Overview***

The definition of a commodity is a mass-produced unspecialized product and implies the attribute of fungibility. Crude oil is typically referred to as a commodity; however, it is neither unspecialized nor fungible. The crude slate available to U.S. and world-wide refineries consists of a substantial number of different grades and varieties of crude oil. Each crude 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 and transportation and storage logistics.

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

Table of Contents

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 fracturing 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 are expected to continue to increase over the next five years and potentially beyond. This production is being developed both in mature producing areas such as the Rockies, the Permian Basin in West Texas and the Mid-Continent region, as well as in less mature, but rapidly growing areas such as the Eagle Ford Shale in South Texas and the Bakken Shale in North Dakota. We forecast that by December 2017, crude oil production in the United States and Canada will have increased by an average of approximately 2.9 million barrels per day from fourth-quarter 2013 levels, 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 combined with actual and anticipated volumes from Canada have strained or are expected to strain 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. For example, the quantity of crude oil transported from the Gulf Coast area into the Midwest has declined, but the overall change in crude oil flows has resulted in an increased demand for storage and terminalling services at Cushing, Oklahoma and Patoka, Illinois.

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 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. Thus far it appears that the rest of the world has been able to absorb the previously imported barrels, but that could change over time as worldwide demand fluctuates.

Since reaching a multi-year low in 2009, U.S. net refinery inputs of crude oil have slowly increased to a level of 15.2 million barrels per day for the twelve month period ending November 2013, 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 out to 2020 and is derived from recent information published by the EIA (see EIA website at *www.eia.doe.gov*). The amounts in the 2013 column are based on the 12 months ended November 2013**.** 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)** | | | |
|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2020** |
| | **(In millions of barrels per day)** | | | | |
| Supply | | | | | |
| Domestic Crude Oil Production | 7.4 | 8.5 | 9.0 | 9.5 | 9.6 |
| Net Imports - Crude Oil from Canada | 2.4 | 3.1 | 3.3 | 3.2 | 3.1 |
| Net Imports - Crude Oil from Other | 5.2 | 3.4 | 2.9 | 2.5 | 2.7 |
| Other (Supply Adjustment / Stock Change) | 0.2 | | | | |
| Crude Oil Input to Domestic Refineries | 15.2 | 15.0 | 15.2 | 15.3 | 15.3 |

| | | | | | |
|---|---|---|---|---|---|
| | | | | | |
| Product Imports | 1.9 | 1.9 | 2.0 | 2.1 | 2.1 |
| Product Exports | (2.9) | (2.9) | (3.0) | (3.0) | (3.0) |
| Net Product Imports / (Exports) | (1.0) | (1.0) | (1.0) | (0.9) | (0.9) |
| | | | | | |
| Supply from Renewable Sources | 1.0 | 0.9 | 1.0 | 1.0 | 1.0 |
| Other - (NGL Production, Refinery Processing Gain) | 3.6 | 3.9 | 4.0 | 4.0 | 4.0 |
| Total Domestic Petroleum Consumption | 18.8 | 18.8 | 19.2 | 19.4 | 19.5 |

(1) Amounts may not recalculate due to rounding.

Table of Contents

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 2013 and is derived from information published by the EIA (see EIA website at *www.eia.doe.gov*):

| **Petroleum Administration Defense District (in millions of barrels per day) (1)** | **Regional Supply** | **Refinery Demand** | **Supply Shortfall** |
|---|---|---|---|
| PADD I (East Coast) | | 1.0 | (1.0) |
| PADD II (Midwest) | 1.4 | 3.4 | (2.0) |
| PADD III (South) | 4.3 | 7.9 | (3.6) |
| PADD IV (Rockies) | 0.5 | 0.6 | (0.1) |
| PADD V (West Coast) | 1.1 | 2.3 | (1.2) |
| Total U.S. | 7.4 | 15.2 | (7.9) |

(1) Amounts may not recalculate or cross-foot due to rounding.

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:

- the multi-year growth in North American crude oil production;
- 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) a 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.

***Refined Products Market Overview***

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

Table of Contents

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

Demand for refined products has generally been affected by price levels, economic growth trends, conservation, fuel efficiency mandates and, to a lesser extent, weather conditions. From 2008 through the 12 months ended November 2013, petroleum consumption averaged approximately 18.8 million barrels per day, an approximate 10% decrease from peak levels, largely due to economic weakness and increased and expanding fuel efficiency standards. Given this decreased demand for refined products, the increased use of ethanol and other renewable fuels and the resulting excess refining capacity, a number of U.S. refineries reduced output and, in some cases, indefinitely shut-down. The EIA is currently forecasting growth in overall refined product demand to increase marginally over the next decade.

The level of future domestic demand generally will be influenced by economic conditions as well as the absolute prices of the products. Counteracting the impact of decreased domestic refined product demand on many U.S. refineries has been the combination of a significant decrease in refined product imports and a significant increase in refined product exports. Refined product imports decreased from 3.2 million barrels per day in 2005 to an average of approximately 1.9 million barrels per day for the 12 months ended November 2013. Conversely, refined product exports increased from approximately 1.1 million barrels per day in 2005 to 2.9 million barrels per day for the 12 months ended November 2013. We believe that potential demand growth will be met primarily by the increase in mandated alternative fuels and increased utilization of existing refining capacity, which could generate demand for midstream infrastructure in certain areas, including pipelines and terminals.

***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, butane, and natural gasoline, which liquefy at moderate pressures thus making it easier to transport and store such products as compared to ethane. As discussed above, 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 75%) 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.

Table of Contents

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

NGL products from refineries represent approximately 19% 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 6% 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.  In addition, there are several other production hubs, including Empress, Alberta and Hobbs, New Mexico. The West Virginia/Western Pennsylvania area is also rapidly developing as a meaningful NGL infrastructure hub.

*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.*  NGL supplies from gas processing plants are increasing rapidly due to the increased drilling activity in unconventional resource plays. Numerous industry and financial analysts project NGL supply volumes will continue to grow over the next several years with some analysts projecting U.S. supply volumes to increase from 2013 levels over 30% by 2017.  A significant amount of this volume is expected to come from recently discovered, unconventional resource plays that do not have the NGL infrastructure to process the wet natural gas or transport, fractionate, and store the NGL products.  Nor are these new supply areas near historical markets for the NGL purity products.  As a result of these dynamics, substantial incremental infrastructure is likely to be developed throughout the NGL value chain over the next several years, and traditional regional basis relationships could change significantly.  The expected continuation of a relatively low ratio of North American gas and NGL prices to world-wide crude oil prices means North American NGL will continue to be competitive on a world scale, either as feedstock for North American based manufacturing or export to overseas markets.  Thus, 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 a supply cost advantage on a world scale.  In addition, growing production of Canadian heavy crude oil is likely to create demand for additional diluents, primarily natural gasoline and butane. The remaining product not absorbed domestically will likely drive continued growth in the NGL export market. Due to rapid increases in NGL production, the prices of NGL (particularly ethane and propane) have been pressured relatively downward in certain regions. It is difficult to predict when such prices may rebound but this downward pressure on prices is one of the key drivers for the new infrastructure development referred to above. 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;

Table of Contents

- 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.

***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) increased availability of storage capacity due to both new construction and the release of previously contracted storage capacity into the market as customers reduce their storage positions and/or exit the market, (iii) a reduction in overall market depth due to various companies exiting the physical gas marketing business, and (iv) lower basis differentials due to expansion and improved connectivity of natural gas transportation infrastructure over the last five years. Due to these factors, both seasonal spreads, which are a proxy for the current intrinsic value of natural gas storage, and volatility levels, which impact the value we are able to realize on a short-term basis from our hub service and merchant storage activities, have been low relative to values experienced during the last seven 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.

However, projected seasonal spreads for the next few years reflect a directionally similar picture to the challenging market conditions we experienced during most of 2013. While recent extremely cold weather has added volatility and uncertainty to the market in the short term, it is difficult to predict the extent to which such conditions will impact overall market conditions on a longer term basis. A return to and continuation of the market conditions that prevailed during most of 2013 will continue to adversely impact our hub services activities as well as the lease 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 term leases.

Table of Contents

**Description of Segments and Associated Assets**

Under GAAP, we consolidate AAP and PAA and its subsidiaries. We currently have no separate operating activities apart from those conducted by PAA. As such, our segment analysis, presentation and discussion is the same as that of PAA, which conducts its operations through three segments Transportation, Facilities and Supply and Logistics. Accordingly, any references to we, our, and similar terms describing assets, business characteristics or other related matters are references to assets, business characteristics or other matters involving PAA s assets and operations.

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

***Transportation Segment***

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

As of December 31, 2013, 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:

- 16,900 miles of active crude oil and NGL pipelines and gathering systems;
- 24 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;
- 744 trailers (primarily in Canada); and
- 130 transport and storage barges and 62 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, 2013, grouped by geographic location:

| **Region / Pipeline and Gathering Systems (1)** | **System Miles** | **2013 Average Net Barrels per Day (2) (in thousands)** |
|---|---|---|
| **United States Crude Oil Pipelines** | | |
| | | |
| **Permian Basin** | | |
| Basin / Mesa | 599 | 718 |
| Permian Basin Area Systems | 2,944 | 581 |
| **Permian Basin Subtotal** | 3,543 | 1,299 |
| | | |
| **South Texas/Eagle Ford** | | |
| Eagle Ford Area Systems | 439 | 102 |
| | | |
| **Western** | | |
| All American | 138 | 40 |
| Line 63 / Line 2000 | 354 | 113 |
| Other | 129 | 94 |
| **Western Subtotal** | 621 | 247 |
| | | |
| **Rocky Mountain** | | |
| Bakken Area Systems | 953 | 131 |
| Salt Lake City Area Systems | 983 | 131 |
| White Cliffs (3) | 527 | 23 |
| Other | 1,316 | 113 |
| **Rocky Mountain Subtotal** | 3,779 | 398 |
| | | |
| **Gulf Coast** | | |
| Capline (3) | 631 | 151 |
| Other | 898 | 291 |
| **Gulf Coast Subtotal** | 1,529 | 442 |
| | | |
| **Central** | | |
| Mid-Continent Area Systems | 2,298 | 281 |
| Other | 313 | 124 |
| **Central Subtotal** | 2,611 | 405 |
| | | |
| **United States Total** | **12,522** | **2,893** |
| | | |
| **Canada** | | |
| Crude Oil Pipelines: | | |
| Manito | 555 | 46 |
| Rainbow | 858 | 124 |
| Rangeland | 1,316 | 60 |
| South Saskatchewan | 341 | 51 |
| Other | 99 | 102 |
| **Crude Oil Pipelines Subtotal** | 3,169 | 383 |
| NGL Pipelines: | | |
| Co-Ed | 772 | 56 |
| Other | 435 | 194 |
| **NGL Pipelines Subtotal** | 1,207 | 250 |

| | | |
|---|---|---|
| **Canada Total** | **4,376** | **633** |
| **Grand Total** | **16,898** | **3,526** |

(1) Ownership percentage varies on each pipeline and gathering system ranging from approximately 20% to 100%. In 2013, we sold certain of our refined products pipeline systems and related assets.

(2) Represents average volume for the entire year attributable to our interest.

(3) Pipelines operated by a third party.

Table of Contents

**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 144,000 barrels per day to 450,000 barrels per day (approximately 125,000 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 approximately 512,000 barrels per day (attributable to our interest) during 2013. 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 2013, we announced a project to increase capacity on the segment from Jal to Wink/Hendrick from 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), which will be completed in 2014.

*Mesa Pipeline System.* We own a 63% 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 360,000 barrels per day (approximately 226,800 barrels per day attributable to our interest). System throughput (as measured by tariff volumes) was approximately 206,000 barrels per day (attributable to our interest) during 2013.

*Permian Basin Area Systems.* We operate wholly owned systems of approximately 2,950 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. These systems are subject to tariff rates regulated by either the FERC or state regulatory agencies. During 2012 and 2013, we completed construction of multiple expansion and extension projects servicing the Bone Spring, Spraberry and Wolfberry producing areas in the Permian Basin. For 2013, combined throughput on the Permian Basin area systems totaled an average of approximately 581,000 barrels per day.

In 2013, we announced several new projects to increase and expand our Permian Basin infrastructure over the next few years to support crude oil production growth. These projects are expected to be completed in stages throughout 2014 and early 2015 and include:

- a new 310-mile crude oil pipeline extending from McCamey to Gardendale, Texas to provide 200,000 barrels per day (which, based on shipper demand, may be increased to 250,000 barrels per day) of additional takeaway capacity from the Permian Basin (the Cactus Pipeline );

- a new 40-mile crude oil pipeline with 100,000 barrels per day of pipeline capacity from Monahans to Crane, Texas to supply volumes to a third-party pipeline as well as the Cactus Pipeline;

- a new 62-mile crude oil pipeline with 200,000 barrels of takeaway capacity from the South Midland Basin to the origin of the Cactus Pipeline at McCamey; and

- a new 80-mile crude oil pipeline between Midland and Colorado City, Texas that will provide an additional 250,000 barrels per day of capacity to supply connecting carriers at Colorado City.

Table of Contents

**SouthTexas/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 439 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 a marine terminal facility at Corpus Christi, as well as the Houston market via Enterprise Products Partners L.P. s ( Enterprise ) connection at Lyssy, Texas. For 2013, total average throughput on our Eagle Ford Area Systems was approximately 102,000 barrels per day.

In 2013, we and Enterprise announced an expansion of the Eagle Ford joint venture pipeline to increase the pipeline s capacity to 470,000 barrels per day. This expansion, which also includes the construction of an additional 2 million barrels of operational storage capacity, is expected to be in service in the second quarter of 2015.

**Western**

*All American Pipeline System.* We own a 100% interest in the All American Pipeline system. The All American Pipeline is a common carrier crude oil pipeline system that transports crude oil produced from two outer continental shelf, or OCS, fields offshore California via connecting pipelines to refinery markets in California. The system 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 a 100% interest in the Line 63 system. The Line 63 system is an intrastate common carrier crude oil pipeline system that transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. The Line 63 system consists of a 144-mile trunk pipeline, 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 148 miles of gathering pipelines in the San Joaquin Valley, with a throughput capacity of approximately 72,000 barrels per day. We also have approximately 1 million barrels of storage capacity on this system. These storage assets are used primarily to facilitate the transportation of crude oil on the Line 63 system.

During the fourth quarter of 2009, a 71-mile segment of Line 63 was temporarily taken out of service to allow for certain repairs and realignments to be performed. Line 63 volumes are currently being redirected from the north end of this out-of-service segment to the parallel Line 2000. The product is then batched along Line 2000 until it is re-injected into the active portion of Line 63, which is south of the out-of-service segment, for subsequent delivery to customers. This temporary pipeline segment closure and redirection of product has not impacted our normal throughput levels on this line. In 2013, we commenced a project to place this idle segment into service. We expect the project to be completed by mid-2015. For 2013, combined throughput on Line 63 totaled an average of approximately 52,000 barrels per day.

*Line 2000.* We own and operate 100% of Line 2000, an intrastate common carrier crude oil pipeline that originates at our Emidio Pump Station (part of the All American Pipeline System) and transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin. Line 2000 is an approximate 130-mile, 20-inch trunk pipeline with a throughput capacity of approximately 130,000 barrels per day. During 2013, throughput on Line 2000 (excluding Line 63 volumes) averaged approximately 61,000 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 Butte Pipe Line. These Bakken Area Systems consist of 953 miles of pipeline, with total average throughput for 2013 of approximately 131,000 barrels per day.

Table of Contents

*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 693 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 2013, throughput on these systems (excluding Frontier Pipeline) in total averaged approximately 124,000 barrels per day.

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 2013, throughput on Frontier averaged approximately 7,000 barrels per day (attributable to our interest).

*White Cliffs Pipeline.* We own an approximate 36% interest in the White Cliffs Pipeline, a 527-mile, 12-inch common carrier pipeline that originates in Platteville, Colorado and terminates in Cushing, Oklahoma. Rose Rock Midstream, L.P. serves as the operator of the pipeline. For 2013, throughput on White Cliffs Pipeline averaged approximately 23,000 barrels per day (attributable to our interest). In 2012, White Cliffs announced an expansion project that will increase total system capacity from 70,000 barrels per day to 150,000 barrels per day and is underpinned by long-term shipper commitments. This expansion is expected to be completed in the first half of 2014.

**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.

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 approximately 151,000 barrels per day during 2013.

*Gulf Coast Pipeline*. We are constructing our Gulf Coast Pipeline, an approximate 42-mile pipeline that originates at our Ten Mile facility in Alabama and extends to a refinery on the Gulf Coast. Additionally, we are constructing approximately 600,000 of storage capacity at our Ten Mile facility. We expect this project to be in service by mid-2014.

**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 approximately 2,300 miles of pipeline with transportation and delivery into and out of our terminal facilities at Cushing. For 2013, combined throughput on the Mid-Continent Area systems totaled an average of approximately 281,000 barrels per day.

Included in the Mid-Continent Area Systems is our Mississippian Lime pipeline, which was placed into service in August 2013. This new pipeline, which is supported by a long-term commitment from an area producer, services the increasing crude oil production in Northern Oklahoma and Southern Kansas and provides crude oil transportation to our terminal facilities at Cushing. We are currently constructing two expansions of the Mississippian Lime pipeline, including an approximate 55-mile extension from Coldwater in Comanche County, Kansas to Byron in Alfalfa County, Oklahoma, as well as an approximate 45-mile extension that will extend our pipeline infrastructure into Logan County and farther into Grant County, Oklahoma. Each of these expansions is expected to be brought into service in the first quarter of 2014 and is supported by a long-term commitment from an area producer.

Also in 2013, we commenced construction of a 95-mile extension of our existing Oklahoma crude oil pipeline system to service increasing production from producing areas in Western Oklahoma and the Texas Panhandle. This new Western Oklahoma pipeline will provide up to 75,000 barrels per day of new takeaway capacity from Reydon, Oklahoma to our existing Orion station in Major County, Oklahoma. This pipeline is supported by long-term producer commitments and is expected to be in service by the first quarter of 2014.

Table of Contents

**Canada Pipelines**

***Crude Oil Pipelines***

*Manito.* We own a 100% interest in the Manito heavy oil system. This 555-mile system is comprised of the Manito pipeline, the North Sask pipeline and the Bodo/Cactus Lake pipeline. Each system consists of a blended crude oil line and a parallel diluent line which delivers condensate to upstream blending locations. The North Sask pipeline is 84 miles in length and originates near Turtleford, Saskatchewan and terminates in Dulwich, Saskatchewan. The Manito pipeline includes 334 miles of pipeline, and the mainline segment originates at Dulwich and terminates at Kerrobert, Saskatchewan. The Bodo/Cactus Lake pipeline is 137 miles long and originates in Bodo, Alberta and also terminates at our Kerrobert storage facility. The Kerrobert storage and terminalling facility is connected to the Enbridge pipeline system and can both receive and deliver heavy crude from and to the Enbridge pipeline system. For 2013, approximately 46,000 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 a 480-mile, 20-inch to 24-inch mainline crude oil pipeline extending from the Norman Wells Pipeline connection in Zama, Alberta to Edmonton, Alberta that has a throughput capacity of approximately 220,000 barrels per day and has 190 miles of gathering pipelines. In September 2013, we placed into service a 188-mile, 10-inch pipeline to transport diluent north from Edmonton, Alberta to our Nipisi truck terminal in Northern Alberta. This new pipeline has an initial capacity of 35,000 barrels per day and is expandable to 70,000 barrels per day. Total average throughput during 2013 on the Rainbow system was approximately 124,000 barrels per day.

*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 646 miles of 3-inch to 8-inch gathering pipelines. The Rangeland system transports NGL mix, butane, condensate, light sweet crude and light sour crude either north to Edmonton, Alberta or south to the U.S./Canadian border near Cutbank, Montana, where it connects to our Western Corridor system. Total average throughput during 2013 on the Rangeland system was approximately 60,000 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 181 miles of 6-inch to 12-inch gathering pipelines from the Rapdan area to Cantuar. The South Saskatchewan system transports heavy crude oil from four gathering areas in southern Saskatchewan to Enbridge s Mainline at Regina. Total average throughput during 2013 on the South Saskatchewan system was approximately 51,000 barrels per day.

***NGL Pipelines***

*Co-Ed NGL Pipeline System.* We own a 100% interest in and are the operator of the Co-Ed NGL Pipeline System, which consists of approximately 772 miles of 3-inch to 10-inch pipeline. This pipeline 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 2013, throughput averaged approximately 56,000 barrels per day.

***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, 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 leases and processing arrangements. Revenues generated in this segment include (i) storage fees that are generated when we lease storage capacity, (ii) terminal throughput fees that are generated when we receive crude oil, refined products or NGL from one connecting source and redeliver the applicable product to another connecting carrier, (iii) loading and unloading fees at our rail terminals, (iv) hub service fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing services, (v) revenues from the sale of natural gas, (vi) fees from NGL fractionation and isomerization and (vii) fees from natural gas and condensate processing services.

As of December 31, 2013, we owned, operated or employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 74 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 17 Bcf of owned base gas;
- 11 natural gas processing plants located throughout Canada and the Gulf Coast area of the United States;
- a condensate stabilization 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;
- 24 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; and
- approximately 1,250 miles of active pipelines that support our facilities assets, consisting primarily of NGL and natural gas pipelines.

Table of Contents

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, 2013, grouped by product and service type and capacity and volume as indicated:

| **Crude Oil and Refined Products Storage Facilities** | **Total Capacity (MMBbls)** |
|---|---|
| *Cushing* | 20 |
| *Kerrobert* | 1 |
| *LA Basin* | 8 |
| *Martinez and Richmond* | 5 |
| *Mobile and Ten Mile* | 2 |
| *Patoka* | 6 |
| *Philadelphia Area* | 4 |
| *St. James* | 9 |
| *Yorktown* (1) | 6 |
| *Other* | 13 |
| | 74 |

| **NGL Storage Facilities** | **Total Capacity (MMBbls)** |
|---|---|
| *Bumstead* | 4 |
| *Fort Saskatchewan* | 4 |
| *Sarnia Area* | 8 |
| *Tirzah* | 1 |
| *Other* | 6 |
| | 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 (Bcf/d)** | **Net Gas Processing Capacity (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 (Bpd)** |
|---|---|
| *Gardendale* | 80,000 |

| **NGL Fractionation and Isomerization Facilities** | **Ownership Interest** | **Total Inlet Volume (3) (Bpd)** | **Gross Capacity (Bpd)** | **Net Capacity (Bpd)** |
|---|---|---|---|---|
| *Fort Saskatchewan* | 21-100% | 23,332 | 75,000 | 51,300 |
| *Sarnia* | 62-84% | 53,788 | 120,000 | 90,000 |
| *Shafter* | 100% | 8,951 | 14,000 | 14,000 |

| | | | | |
|---|---|---|---|---|
| *Other* | 82-100% | 10,255 | 26,800 | 24,973 |
| | | 96,326 | 235,800 | 180,273 |

| **Rail Facilities** | **Ownership Interest** | **Loading Capacity (4) (Bpd)** | **Unloading Capacity (4) (Bpd)** |
|---|---|---|---|
| *Crude Oil Rail Facilities* | 100% | 211,000 | 280,000 |

| | **Ownership Interest** | **Number of Rack Spots** | **Number of Storage Spots** |
|---|---|---|---|
| *NGL Rail Facilities* (5) | 50-100% | 247 | 1,135 |

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

(2) 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 facility 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, which have increased the capacity of the Cushing Terminal to a total of approximately 20 million barrels. During 2013, we added approximately 1.1 million barrels of such storage capacity through the construction of four 270,000 barrel tanks. We also added additional delivery capacity through the installation of a high volume meter. During mid-2013, we commenced construction of an additional 0.5 million barrels of storage capacity, which is expected to be placed into service in stages throughout 2014.

*Kerrobert Terminal.* We own a crude oil and condensate storage and terminalling facility, which is located near Kerrobert, Saskatchewan and is connected to our Manito and Cactus Lake pipeline systems. The total storage capacity at the Kerrobert terminal is approximately 1 million barrels. This facility is also connected to the Enbridge pipeline system and can both receive and deliver heavy crude from and to the Enbridge pipeline system.

*L.A. Basin.* We own four crude oil and refined product storage facilities in the Los Angeles area with a total of approximately 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 service). Our San Francisco area terminals have approximately 5 million barrels of combined storage capacity that are connected to area refineries through a network of owned and third-party pipelines that carry crude oil and refined products to and from area refineries. The terminals have dock facilities and our Richmond terminal is also able to receive products by rail.

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

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

*Patoka Terminal.* Our Patoka Terminal has approximately 6 million barrels of storage capacity and the associated manifold and header system at the Patoka Interchange located in southern Illinois. Our terminal is connected 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 approximately 4 million barrels. The terminals have 20 truck loading lanes, two barge docks and a ship dock. The Philadelphia area terminals provide services and products to all of the refiners in the Philadelphia harbor. The Philadelphia area terminals also receive products from connecting pipelines.

*St. James Terminal.* We have approximately 9 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. See -Rail Facilities below for further discussion.

In 2013, we added approximately 0.6 million barrels of crude oil storage capacity to the St. James terminal, and we expect to add approximately 1.1 million barrels of crude oil storage capacity throughout 2014. These expansions are supported by multi-year contracts and throughput arrangements with third-party customers.

*Yorktown Terminal.* We have approximately 6 million barrels of storage for crude oil, black oil, propane, butane and refined products at the Yorktown facility, including 1.6 million barrels of capacity for which we hold lease options (1.1 million barrels 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. We are in the process of making a number of modifications to the Yorktown facility, which will enhance the capabilities of the rail system, the dock facilities and related infrastructure, and increase connectivity and flexibility within the terminal itself. Portions of these projects were completed in the fourth quarter of 2013, with the balance expected to be completed in early 2014.

**NGL Storage Facilities**

*Bumstead.* The Bumstead facility is located at a major rail transit point near Phoenix, Arizona. With approximately 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 21 storage caverns with approximately 4 million barrels in useable storage capacity. NGL mix and spec products can be delivered to the Enbridge pipeline in addition to the propane truck loading rack at the facility. 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 additional NGL storage caverns and approximately 2.5 million barrels of additional 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 rail car 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 which will facilitate the removal of excess brine via truck from our Sarnia facility. The project is expected to increase useable NGL storage capacity at the facility by as much as 3 million barrels when completed.

Table of Contents

The Windsor storage terminal in Windsor, Canada, is a pipeline hub and underground storage facility. The facility is served by three Plains owned receipt/dispatch pipelines, the Cochin pipeline 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 plan to initiate a brine disposal program which 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 a Plains owned pipeline.  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, 2013, 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 19 interconnects with 12 interstate pipelines and 4 utility companies.

**Natural Gas Processing Facilities**

We 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. In 2013, we completed a number of modifications to our Patterson, Louisiana gas processing facility, which included new pipeline and customer connections.

We also 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.

**Condensate Stabilization Facility**

In February 2013, we completed construction of a condensate stabilization facility in La Salle County, Texas which 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 stabilization facility is supplied by long-term commitments from producers. Since the facility began operations, throughput has averaged approximately 40,000 barrels per day.

Table of Contents

In 2013, we announced that we will add a third condensate 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 the second quarter of 2015.

**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 C3/C4 mix for delivery to the Sarnia facility via the Enbridge pipeline.

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.

*Sarnia.* The Sarnia Fractionator is the largest fractionation plant in Eastern Canada and receives NGL feedstock from the Enbridge Pipeline, the Kalkaska 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.

During the fourth quarter of 2013, we completed construction of 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.

*Gardendale*. In 2013, we announced a project to construct a new NGL fractionator in the Eagle Ford area of South Texas that will have a capacity of up to 15,000 barrels per day of NGL Y-Grade and off-spec Y-Grade product. The fractionator will be located near existing PAA assets in Gardendale (La Salle County), Texas, and will be designed to fractionate NGL Y-Grade and to treat and fractionate off-spec Y-Grade sourced from our area gathering system, our condensate stabilizer and throughout the Eagle Ford producing region. This project, which is supported by long-term third-party commitments, will also include the construction of approximately 80,000 barrels of pressurized storage to accommodate Y-Grade and purity products and is expected to be in service in the second quarter of 2015.

**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 211,000 barrels per day. These facilities are located in Carr, Colorado; Tampa, Colorado; Gardendale, Texas; Manitou, North Dakota; and Van Hook, North Dakota. We placed the Tampa, Colorado facility into service in November 2013.

We are currently expanding 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 expect to complete these expansions in mid-2014 and the first half of 2015, respectively. In addition, we are currently constructing crude oil rail loading facilities in Western Canada, which we expect to be in service in mid-2015.

***Crude Oil Rail Unloading Facilities***

We own two active crude oil rail unloading terminals and have one additional unloading terminal under construction. Our terminal at St. James, Louisiana is connected to our active rail unloading facility that has an unload capacity of 140,000 barrels of sweet crude oil per day. Our Yorktown, Virginia rail facility was placed into service in December 2013. This facility receives unit trains and has an unload capacity of approximately 140,000 barrels per day.

Table of Contents

In connection with our 2012 acquisition of rail terminals from US Development Group, we acquired a project to construct a crude oil unloading terminal near Bakersfield, California. We expect to complete this project during the second half of 2014, at which point this terminal will have permitted capacity to unload 70,000 barrels per day.

***NGL Rail Facilities***

We own nineteen 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 247 railcar rack spots and 1,135 railcar storage spots and we have the ability to switch our own rail cars at six of these terminals.

***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;
- the storage of inventory during contango market conditions and the seasonal storage of NGL;
- 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 to maximize profits; and
- 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.

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

In addition to substantial working inventories associated with its merchant activities, as of December 31, 2013, our supply and logistics segment also owned significant volumes of crude oil and NGL classified as long-term assets for linefill or minimum inventory requirements and employs a variety of owned or leased physical assets throughout the United States and Canada, including approximately:

- 12 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;
- 843 trucks and 982 trailers; and
- 7,400 crude oil and NGL railcars.

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

Table of Contents

The following table shows the average daily volume of our supply and logistics activities for the year ended December 31, 2013 (in thousands of barrels per day):

| | Volumes |
|---|---|
| Crude oil lease gathering purchases | 859 |
| NGL sales | 215 |
| Waterborne cargos | 4 |
| Supply and Logistics activities total | 1,078 |

*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 eight years. We utilize our truck fleet and gathering pipelines as well as leased railcars, third-party pipelines, trucks and barges to transport the crude oil to market. In addition, we purchase foreign crude oil. Under these contracts we may purchase crude oil upon delivery in the United States or we may purchase crude oil in foreign locations and transport it on third-party tankers.

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 five to 10 year 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 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. We sell NGL primarily to propane and refined product retailers, petrochemical companies and refiners, and limited volumes to other marketers. A majority of our crude oil and NGL contracts generally range in term from a thirty-day evergreen to one year terms. 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. Through these transactions, we seek to maintain a position that is substantially balanced between purchases and sales and future delivery obligations. From time to time, we enter into various types of sale and exchange transactions including fixed price delivery contracts, floating price collar arrangements, financial swaps and crude oil and 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.

Table of Contents

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

When we sell crude oil, NGL, natural gas and refined products, we must determine the amount, if any, of the line of credit to be extended to any given customer. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits, 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 supply and logistics activities, which generally have higher activity levels during the first and fourth quarters of each year.

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

Through our three business segments, we are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products, 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 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 2013, West Texas Intermediate crude oil prices traded within a range of $87 to $111 per barrel.

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

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

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

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. Conversely, when there is a higher demand than supply of crude oil, NGL or natural gas in the near term, the market is backwardated, meaning that the price for future deliveries is lower than current prices. In a backwardated market, hedged positions established in a contango market can be unwound, with the physical product or futures position sold into the current higher priced market at a level that mitigates losses associated with closing out future delivery obligations.

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

***Risk Management***

In order to hedge margins involving our physical assets and manage risks associated with our various commodity purchase and sale obligations and, in certain circumstances, to realize incremental margin during volatile market conditions, we use derivative instruments. 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, refined products, 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 18 to our Consolidated Financial Statements.

**Customers**

Marathon Petroleum Corporation and its subsidiaries accounted for approximately 15% of our revenues for the year ended December 31, 2013 and approximately 16% of our revenues for each of the years ended December 31, 2012 and 2011. ExxonMobil Corporation and its subsidiaries accounted for approximately 13%, 13% and 10% of our revenues for the years ended December 31, 2013, 2012 and 2011, respectively. Phillips 66 and its subsidiaries accounted for approximately 11% of our revenues for the year ended December 31, 2013. ConocoPhillips Company (prior to the spin-off of Phillips 66, which was effective May 1, 2012) accounted for approximately 10% of our revenues for the year ended December 31, 2011. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2013, 2012 and 2011. 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. For a discussion of customers and industry concentration risk, see Note 13 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 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 $57 million in 2013, $39 million in 2012 and $32 million in 2011. Based on currently available information, our preliminary estimate for 2014 is that we will incur approximately $25 million in operational expenditures and approximately $52 million in capital 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 internal programs designed to prevent incidents and includes activities such as automating valves and replacing river crossings. Costs incurred for such activities were approximately $22 million in 2013, $24 million in 2012 and $22 million in 2011, and our preliminary estimate for 2014 is that we will incur approximately $47 million.

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.

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

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

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

The DOT has adopted American Petroleum Institute Standard 653 ( API 653 ) as the standard for the inspection, repair, alteration and reconstruction of steel aboveground petroleum storage tanks subject to DOT jurisdiction. API 653 requires regularly scheduled inspection and repair of tanks remaining in service. In the United States, costs associated with this program were approximately $26 million, $31 million and $22 million in 2013, 2012 and 2011, respectively. For 2014, 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 audit of PMC s operations. Although we believe that all material aspects of the order (costs and operational effects) have been incorporated into our budgeting and planning process, future proceedings 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 internal programs designed to prevent incidents and includes activities 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 $90 million in 2013, $80 million in 2012 and $35 million in 2011. Our preliminary estimate for 2014 is approximately $106 million. Significant additional expenses could be incurred if new or more stringently interpreted pipeline safety requirements are implemented.

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. Since asset acquisitions are an integral part of our business strategy, as we acquire additional assets, we may be required to incur additional costs to ensure that the acquired assets comply with the regulatory standards in the United States and Canada.

***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 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 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.

Table of Contents

***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 U.S. EPA adopted rules for establishing a GHG emissions reporting program. Fewer than ten of our facilities are presently subject to the federal GHG reporting requirements. These include facilities with combustion GHG emissions and potential fugitive emissions above the reporting thresholds. We import sufficient quantities of finished fuel products into the 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. 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 to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they would otherwise emit large volumes of GHGs. The EPA is in the process of identifying what constitutes best available control technology for various sources of GHG emissions, but it appears likely that the agency will seek to impose energy efficiency requirements on sources that burn large volumes of fossil fuels rather than post-combustion GHG capture requirements. If the EPA imposes energy efficiency requirements, we do not anticipate that they will have an adverse effect on the cost of our operations.

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

The WCI originally included several U.S. states and Canadian provinces, either as full voting members or observers. Most U.S. states have withdrawn from WCI, with California the sole remaining member from the United States. California has implemented a GHG cap-and-trade program, authorized under Assembly Bill 32 ( AB32 ). The California Air Resources Board has published a list of facilities expected to be subject to this program. At this time, the list only includes one of our facilities, the Lone Star Gas Liquids facility in Shafter, California. The rules implementing the AB32 program were finalized in December 2011, and the first auction of GHG emission credits was conducted in the fall of 2012, with the average credit selling for $10.09 per ton. 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 AB-32 compliance obligations after the year 2020.

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. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events that could have an adverse effect on our assets and operations.

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

**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. Originally, this framework was intended to be implemented by 2010; however no federally mandated reduction targets for GHGs have been implemented to date. Since 2004, companies emitting more than 100 thousand tons per year ( kt/y ) of $CO_2$ equivalent ( $CO_2e$ ) were required to report their GHG emissions under the Greenhouse Gas Emissions Reporting Program. In 2010, this reporting threshold was reduced to 50 kt/y. Two PMC facilities meet this reporting threshold.

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 had 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 16 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 ). NWP is supported by strong statutory and regulatory history and was originally approved by Congress in 1977. In a June 2012 lawsuit (*Sierra Club v. Bostick*), to which we were not a party, a plaintiff sought to have the court strike down the NWP and enjoin the construction of a particular oil pipeline project that would run from Cushing, Oklahoma to oil refineries along the Gulf Coast near Port Arthur, Texas. In August 2012, a District Court denied the motion to enjoin the construction and ruled that the Corps had acted properly in approving the project under the NWP. The District Court s decision was reaffirmed by the Tenth Circuit Court of Appeals in October 2013. 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.

**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.

Table of Contents

*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.

***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.

Table of Contents

**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 among other things to monitor: (i) driver operations, (ii) log book maintenance, (iii) truck manifest preparations, (iv) safety placard placement on the trucks and trailers, (v) operation and equipment safety and (vi) many other aspects of trucking operations. We are also subject to Occupational Health and Safety regulations with respect to our trucking operations. 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.

Recent 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 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 recent accidents could also prompt 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 has recommended that all tank cars used to carry crude oil be reinforced to make them more resistant to punctures if trains derail. This recommendation has not yet been adopted by PHMSA. PHMSA has said that it is considering amendments to current regulations that would enhance rail safety, including for DOT-111 railcars, but the rules are still under development. Any requirement to retrofit and upgrade existing rail tankers (DOT-111 or other models) could involve substantial cost to the partnership and we can provide no assurance that such a future compliance obligation will not have a material adverse impact on our financial condition or results of operations.

***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.

Table of Contents

***Market Anti-Manipulation Regulation***

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

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

***Natural Gas Storage Regulation***

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 shareholders 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 FERC approved tariffs. We have been granted market-based rate authorization for the services that our facilities provide. Market-based rate authority allows us to negotiate rates with individual customers based on market demand.

The FERC also has authority over the siting, construction, and operation of 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.

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 shareholders.

Table of Contents

**Operational Hazards and Insurance**

Pipelines, terminals, trucks or other facilities or equipment may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. Since the time we and our predecessors commenced midstream crude oil activities in the early 1990s, we have maintained insurance of various types and varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. However, such insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. Consistent with insurance coverage generally available to the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences. Over the last several years, our operations have expanded significantly, with total assets increasing over 30 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 public liability and property damage to others with respect to our operations. We believe that our levels of coverage and retention are generally consistent with those of similarly situated companies in our industry. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable, or that we have established adequate reserves to the extent that such risks are not insured.

**Title to Properties and Rights-of-Way**

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

**Employees and Labor Relations**

Through GP LLC or its affiliates, we employed approximately 4,900 employees at December 31, 2013. None of the employees are subject to a collective bargaining agreement, except for eight 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. We consider employee relations to be good.

Table of Contents

**Summary of Tax Considerations**

*The following is a summary of material U.S. federal income tax consequences, tax considerations, and in the case of a non-U.S. holder, estate tax consequences related to the purchase, ownership and disposition of our Class A shares by a taxpayer that holds our Class A shares as a capital asset (generally property held for investment). This summary is based on the provisions of the Internal Revenue Code of 1986, as amended ( the Code ), U.S. Treasury regulations and administrative rulings and judicial decisions, all as in effect on the date hereof, and all of which are subject to change, possibly with retroactive effect. We have not sought any ruling from the Internal Revenue Service, or the IRS, with respect to the statements made and the conclusions reached in the following summary, and there can be no assurance that the IRS will agree with such statements and conclusions.*

*This summary does not address all aspects of U.S. federal income and estate taxation or the tax considerations arising under the laws of any non-U.S., state, or local jurisdiction, or under U.S. federal gift tax laws. In addition, this summary does not address tax considerations applicable to investors that may be subject to special treatment under the U.S. federal income tax laws. The tax consequences of ownership of Class A shares depends in part on the owner s individual tax circumstances. It is the responsibility of each shareholder, 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 shareholder s investment in us. Further, it is the responsibility of each shareholder to file all U.S. federal, Canadian, state, provincial and local tax returns that may be required of the shareholder. Also see Item 1A. Risk Factors Tax Risks.*

***Corporate Status***

Although we are a Delaware limited partnership, we have elected to be treated as a corporation for U.S. federal income tax purposes. As a result, we are subject to tax as a corporation and distributions on the Class A shares will be treated as distributions on corporate stock for federal income tax purposes. No Schedule K-1s will be issued with respect to the Class A shares, but instead holders of Class A shares will receive a Form 1099 from us with respect to distributions received on the Class A shares.

***Consequences to U.S. Holders***

The discussion in this section is addressed to holders of our Class A shares who are U.S. holders for U.S. federal income tax purposes. A U.S. holder for purposes of this discussion is a beneficial owner of our Class A shares and who is, for U.S. federal income tax purposes:

- an individual citizen or resident of the United States;

- a corporation, or other entity taxable as a corporation for U.S. federal income tax purposes, that was created or organized in or under the laws of the United States, any state thereof or the District of Columbia;

- an estate whose income is subject to U.S. federal income tax regardless of its source; or

- a trust if (i) a U.S. court can exercise primary supervision over the trust s administration and one or more United States persons are authorized to control all substantial decisions of the trust or (ii) certain circumstances apply and the trust has validly elected to be treated as a United States person.

**Distributions**

Distributions with respect to our Class A shares will constitute dividends for U.S. federal income tax purposes to the extent paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. To the extent that the amount of a distribution with respect to our Class A shares exceeds our current and accumulated earnings and profits, such distribution will be treated first as a tax-free return of capital to the extent of the U.S. holder s adjusted tax basis in such Class A shares, which reduces such basis dollar-for-dollar, and thereafter as capital gain. Such gain will be long-term capital gain provided that the U.S. holder has held such Class A shares for more than one year as of the time of the distribution. Non-corporate holders that receive distributions on our Class A shares that are treated as dividends for U.S. federal income tax purposes generally would be subject to U.S. federal income tax at a maximum tax rate of 20% on such dividends provided certain holding period requirements are met.

Both AAP and PAA have made elections permitted by Section 754 of the Code. As a result, our initial acquisition of interests in AAP resulted in basis adjustments with respect to our interest in the assets of AAP (and indirectly in PAA). Such adjustments resulted in depreciation and amortization deductions that we anticipate will offset a substantial portion of our taxable income for an extended period of time. In addition, future exchanges of retained interests in AAP and Class B shares in us for our

Table of Contents

Class A shares will result in additional basis adjustments with respect to our interest in the assets of AAP (and indirectly in PAA). We expect to benefit from additional tax deductions resulting from those adjustments, the amount of which will vary depending on the value of the Class A shares at the time of the exchange.

We do not expect to have any earnings and profits for an extended period of time, which we estimate will include, at a minimum, each of the periods ending December 31, 2014, 2015, and 2016, and we may not have sufficient earnings and profits during future tax years for any distributions on our Class A shares to qualify as dividends for U.S. federal income tax purposes. If a distribution on our Class A shares fails to qualify as a dividend for U.S. federal income tax purposes, U.S. corporate holders would be unable to utilize the corporate dividends-received deduction.

Prospective investors in our Class A shares are encouraged to consult their tax advisors as to the tax consequences of receiving distributions on our Class A shares that do not qualify as dividends for U.S. federal income tax purposes, including, in the case of prospective corporate investors, the inability to claim the corporate dividends received deduction with respect to such distributions.

**Gain on Disposition of Class A Shares**

A U.S. holder generally will recognize capital gain or loss on a sale, exchange, certain redemptions, or other taxable disposition of our Class A shares equal to the difference, if any, between the amount realized upon the disposition of such Class A shares and the U.S. holder s adjusted tax basis in those shares. A U.S. holder s tax basis in the shares generally will be equal to the amount paid for such shares reduced (but not below zero) by distributions received on such shares that are not treated as dividends for U.S. federal income tax purposes. Such capital gain or loss generally will be long-term capital gain or loss if the U.S. holder s holding period for the shares sold or disposed of is more than one year. Long-term capital gains of individuals generally are subject to a reduced maximum U.S. federal income tax rate of 20%. The deductibility of net capital losses is subject to limitations.

**Backup Withholding and Information Reporting**

Information returns generally will be filed with the IRS with respect to distributions on our Class A shares and the proceeds from a disposition of our Class A shares. U.S. holders may be subject to backup withholding on distributions with respect to our Class A shares and on the proceeds of a disposition of our Class A shares unless such U.S. holders furnish the applicable withholding agent with a taxpayer identification number, certified under penalties of perjury, and certain other information, or otherwise establish, in the manner prescribed by law, an exemption from backup withholding. Penalties apply for failure to furnish correct information and for failure to include reportable payments in income.

Backup withholding is not an additional tax. Any amounts withheld under the backup withholding rules will be creditable against a U.S. holder s U.S. federal income tax liability, and the U.S. holder may be entitled to a refund, provided the U.S. holder timely furnishes the required information to the IRS. U.S. holders are urged to consult their own tax advisors regarding the application of the backup withholding rules to their particular circumstances and the availability of, and procedure for, obtaining an exemption from backup withholding.

***Consequences to Non-U.S. Holders***

The discussion in this section is addressed to holders of our Class A shares who are non-U.S. holders for U.S. federal income tax purposes. For purposes of this discussion, a non-U.S. holder is a beneficial owner of our Class A shares that is an individual, corporation, estate or trust that is not a U.S. holder as defined above.

**Distributions**

Generally, a distribution treated as a dividend paid to a non-U.S. holder on our Class A shares will be subject to U.S. withholding tax at a rate of 30% of the gross amount of the distribution, or such lower rate as may be specified by an applicable income tax treaty. To the extent a distribution exceeds our current and accumulated earnings and profits, such distribution will reduce the non-U.S. holder s adjusted tax basis in its Class A shares (but not below zero). The amount of any such distribution in excess of the non-U.S. holder s adjusted tax basis in its Class A shares will be treated as gain from the sale of such shares and will have the tax consequences described below under Gain on Disposition of Class A Shares. The rules applicable to distributions by USRPHCs (as defined below) to non-U.S. persons that exceed current and accumulated earnings and profits are not clear. As a result, it is possible that U.S. federal income tax at a rate not less than 10% (or such lower rate as may be specified by an applicable income tax treaty for distributions from a USRPHC) may be withheld from distributions received by non-U.S. holders that exceed our current and accumulated earnings and profits. To receive the benefit of a reduced treaty rate on distributions, a non-U.S. holder must provide the withholding agent with an IRS W-8BEN (or other appropriate form) certifying qualification for the reduced rate.

Non-U.S. holders are encouraged to consult their tax advisors regarding the withholding rules applicable to distributions on our Class A shares, the requirement for claiming treaty benefits, and any procedures required to obtain a refund of any overwithheld amounts.

Distributions treated as dividends that are paid to a non-U.S. holder and are effectively connected with a trade or business conducted by the non-U.S. holder in the United States (and, if required by an applicable tax treaty, are attributable to a permanent establishment maintained by the non-U.S. holder in the United States) generally will be taxed on a net income basis at the rates and in the manner generally applicable to U.S. persons (as defined under the Code). Effectively connected dividend income will not be subject to U.S. withholding tax if the non-U.S. holder satisfies certain certification requirements by providing to the withholding agent a properly executed IRS Form W-8ECI (or successor form) certifying eligibility for the exemption. If the non-U.S. holder is a corporation, that portion of the corporation s earnings and profits for the taxable year, as adjusted for certain items, that is effectively connected with its U.S. trade or business (and, if required by applicable income tax treaty, is attributable to a permanent establishment maintained by the corporate non-U.S. holder in the United States) may also be subject to a branch profits tax at a 30% rate or such lower rate as may be specified by an applicable tax treaty.

**Gain on Disposition of Class A Shares**

A non-U.S. holder generally will not be subject to U.S. federal income tax on any gain realized upon the sale or other disposition of our Class A shares unless:

- the non-U.S. holder is an individual who is present in the United States for a period or periods aggregating 183 days or more during the calendar year in which the sale or disposition occurs and certain other conditions are met;

- the gain is effectively connected with a trade or business conducted by the non-U.S. holder in the United States (and, if required by an applicable tax treaty, is attributable to a permanent establishment maintained by the non-U.S. holder in the United States); or

- our Class A shares constitute a U.S. real property interest by reason of our status as a United States real property holding corporation, or USRPHC, for U.S. federal income tax purposes.

A non-U.S. holder described in the first bullet point above will be subject to tax at a rate of 30% (or such lower rate as may be specified by an applicable tax treaty) on the amount of such gain (which may be offset by U.S. source capital losses).

A non-U.S. holder whose gain is described in the second bullet point above will be subject to U.S. federal income tax on any gain recognized on a net income basis at the same graduated rates generally applicable to U.S. persons unless an applicable tax treaty provides otherwise. Corporate non-U.S. holders may also be subject to a branch profits tax equal to 30% (or such lower rate as may be specified by an applicable tax treaty) of their effectively connected earnings and profits attributable to such gain, as adjusted for certain items.

Generally, a corporation is a USRPHC if the fair market value of its U.S. real property interests equals or exceeds 50% of the sum of the fair market value of its worldwide real property interests and its other assets used or held for use in a trade or business. We believe that we currently are, and expect to remain for the foreseeable future, a USRPHC for U.S. federal income tax purposes. However, as long as our Class A shares are regularly traded on an established securities market, a non-U.S. holder will be taxable on gain recognized on the disposition of our Class A shares as a result of our status as a USRPHC only if the non-U.S. holder actually or constructively owns, or owned at any time during the five-year period ending on the date of the disposition or, if shorter, the non-U.S. holder s holding period for the Class A shares, more than 5% of our Class A shares. If our Class A shares were not considered to be regularly traded on an established securities market, all non-U.S. holders would be subject to U.S. federal income tax on a disposition of our Class A shares, and a 10% withholding tax would apply to the gross proceeds from the sale of our Class A shares by such non-U.S. holder. Non-U.S. holders should consult their tax advisors with respect to the application of the foregoing rules to their ownership and disposition of our Class A shares.

**U.S. Federal Estate Tax**

Our Class A shares beneficially owned or treated as owned by an individual who is not a citizen or resident of the United States (as defined for U.S. federal estate tax purposes) at the time of death generally will be includable in the decedent s gross estate for U.S. federal estate tax purposes, unless an applicable estate tax treaty provides otherwise, and therefore may be subject to U.S. federal estate tax.

Table of Contents

**Backup Withholding and Information Reporting**

Generally, we must report annually to the IRS and to each non-U.S. holder the amount of dividends paid to such holder, the name and address of the recipient, and the amount, if any, of tax withheld with respect to those dividends. These information reporting requirements apply even if withholding was not required. Pursuant to tax treaties or other agreements, the IRS may make such reports available to tax authorities in the recipient s country of residence.

Payments of dividends to a non-U.S. holder generally will not be subject to backup withholding if the non-U.S. holder establishes an exemption by properly certifying its non-U.S. status on an IRS Form W-8BEN or another appropriate version of IRS Form W-8, provided that the withholding agent does not have actual knowledge, or reason to know, that the beneficial owner is a U.S. person that is not an exempt recipient.

Payments of the proceeds from a sale or other disposition by a non-U.S. holder of our Class A shares effected by or through a U.S. office of a broker generally will be subject to information reporting and backup withholding (at the applicable rate) unless the non-U.S. holder establishes an exemption by properly certifying its non-U.S. status on an IRS Form W-8BEN or another appropriate version of IRS Form W-8 and certain other conditions are met or the non-U.S. holder otherwise establishes an exemption. Information reporting and backup withholding generally will not apply to any payment of the proceeds from a sale or other disposition of our Class A shares effected outside the United States by a foreign office of a broker. However, unless such broker has documentary evidence in its records that the holder is a non-U.S. holder and certain other conditions are met, or the non-U.S. holder otherwise establishes an exemption, information reporting will apply to a payment of the proceeds of the disposition of our Class A shares effected outside the United States by such a broker if it has certain relationships within the United States.

Backup withholding is not an additional tax. Rather, the U.S. income tax liability (if any) of persons subject to backup withholding will be reduced by the amount of tax withheld. If withholding results in an overpayment of taxes, a refund may be obtained, provided that certain required information is timely furnished to the IRS.

***Legislation Affecting Class A Shares Held Through Foreign Accounts***

Legislation enacted in 2010 imposes a 30% withholding tax on any dividends on our Class A shares and on the gross proceeds from a disposition of our Class A shares in each case if paid to a foreign financial institution or a non-financial foreign entity (including, in some cases, when such foreign financial institution or entity is acting as an intermediary), unless (i) in the case of a foreign financial institution, such institution enters into an agreement with the U.S. government to withhold on certain payments, and to collect and provide to the U.S. tax authorities substantial information regarding U.S. account holders of such institution (which includes certain equity and debt holders of such institution, as well as certain account holders that are foreign entities with U.S. owners), (ii) in the case of a non-financial foreign entity, such entity certifies that it does not have any substantial U.S. owners or provides the withholding agent with a certification identifying the direct and indirect substantial U.S. owners of the entity, or (iii) the foreign financial institution or non-financial foreign entity otherwise qualifies for an exemption from these rules. Under certain circumstances, a holder might be eligible for refunds or credits of such taxes.

Payments subject to withholding tax under this law generally include dividends paid on Class A shares after June 30, 2014, and gross proceeds from sales or redemptions of such Class A shares after December 31, 2016. Non-U.S. holders are encouraged to consult their tax advisors regarding the possible implications of this law.

***3.8% Tax on Unearned Income***

Certain holders that are individuals, trusts or estates will be subject to an additional 3.8% Medicare tax on unearned income, which generally will include dividends received and gain recognized with respect to our Class A shares. For individual U.S. holders, the additional Medicare tax applies to the lesser of (i) net investment income, or (ii) the excess of modified adjusted gross income over $200,000 ($250,000 if married and filing jointly or $125,000 if married and filing separately). Net investment income generally equals a holder s gross investment income reduced by the deductions that are allocable to such income. Investment income generally includes passive income such as interest, dividends, annuities, royalties, rents and capital gains. Holders are urged to consult their own tax advisors regarding the application of this additional Medicare tax to their particular circumstances.

Table of Contents

**Available Information**

We make available, free of charge on our Internet website at ir.paagp.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 Inherent in an Investment in Us**

***Our cash flow will be entirely dependent upon the ability of PAA to make cash distributions to AAP, and the ability of AAP to make cash distributions to us.***

The source of our earnings and cash flow currently consist exclusively of cash distributions from AAP, which currently consist exclusively of cash distributions from PAA. The amount of cash that PAA will be able to distribute to its partners, including AAP, each quarter principally depends upon the amount of cash it generates from its business. For a description of certain factors that can cause fluctuations in the amount of cash that PAA generates from its business, please read Risks Related to PAA s Business and Management s Discussion and Analysis of Financial Condition and Results of Operations. PAA may not have sufficient available cash each quarter to continue paying distributions at its current level or at all. If PAA reduces its per unit distribution, either because of reduced operating cash flow, higher expenses, capital requirements or otherwise, we will have less cash available for distribution and would likely be required to reduce our per share distribution. The amount of cash PAA has available for distribution depends primarily upon PAA s cash flow, including cash flow from the release of financial reserves as well as borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, PAA may make cash distributions during periods when it records losses and may not make cash distributions during periods when it records profits.

Furthermore, AAP s ability to distribute cash to us and our ability to distribute cash received from AAP to our Class A shareholders is limited by a number of factors, including:

- AAP s payment of costs and expenses associated with our operations, and the operations of GP LLC, including expenses we incur as a result of being a public company, to the extent they are not subject to reimbursement by PAA;

- our payment of any income taxes;

- interest expense and principal payments on any indebtedness incurred by AAP or us;

- restrictions on distributions contained in AAP s and PAA s respective credit facilities and any future debt agreements entered into by AAP, PAA or us;

- reserves necessary for us to pay a ratable amount to AAP as necessary to permit AAP to make required capital contributions to PAA to maintain AAP s indirect 2% general partner interest in PAA, as required by the partnership agreement of PAA upon the issuance of additional partnership interests by PAA; and

- reserves our general partner establishes for the proper conduct of our business, to comply with applicable law or any agreement binding on us or our subsidiaries (exclusive of PAA and its subsidiaries), which reserves are not subject to a limit pursuant to our partnership agreement.

A material increase in amounts paid or reserved with respect to any of these factors could restrict our ability to pay quarterly distributions to our Class A shareholders.

***The IDRs AAP is entitled to receive may be limited or modified without the consent of our shareholders, which may reduce cash distributions to our Class A shareholders.***

At December 31, 2013, we owned a 22.1% limited partner interest in AAP, which owns all of PAA s IDRs, which entitle AAP to receive increasing percentages (up to a maximum of 48%, to the extent not modified) of any cash distributed by PAA in excess of $0.225 per PAA common unit in any quarter. The vast majority of the cash flow we receive from AAP is derived from its ownership of these IDRs.

Table of Contents

PAA, like other publicly traded partnerships, will generally only undertake an acquisition or expansion capital project if, after giving effect to related costs and expenses, the transaction would be expected to be accretive, meaning it would increase cash distributions per unit in future periods. Because AAP currently participates in the IDRs at all levels, including the highest sharing level of 48%, to the extent not modified, it is harder for an acquisition or capital project to show accretion for the common unitholders of PAA than if the IDRs received less incremental cash flow. We therefore expect that AAP may determine, in certain cases, to propose a reduction to the IDRs to facilitate a particular acquisition or expansion capital project. Any such reduction of IDRs will reduce the amount of cash that would have otherwise been distributed by AAP to us, which will in turn reduce the cash distributions we would otherwise be able to pay to our Class A shareholders. Our shareholders will not be able to vote on, or otherwise prohibit our general partner from taking, similar actions in the future and our general partner may elect to modify the IDRs without considering the interests of the holders of the Class A shares. In addition, there can be no guarantee that the expected benefits of any IDR modification will be realized.

***A reduction in PAA s distributions below certain levels will lead to a disproportionately greater reduction in the amount of cash distributions to which AAP is currently entitled.***

AAP s ownership of PAA s IDRs entitle it to receive increasing percentages, ranging from 13% up to 48%, to the extent not modified, of all cash distributed by PAA in excess of $0.225 per PAA common unit per quarter. A decrease in the amount of distributions paid by PAA to less than $0.3375 per PAA common unit per quarter would reduce AAP s percentage of incremental cash distributions in excess of $0.225 per PAA common unit per quarter from 48% to as low as 13%. As a result, any such reduction in quarterly cash distributions from PAA would have the effect of disproportionately reducing the amount of distributions that AAP receives from PAA in respect of the IDRs as compared to cash distributions PAA makes with respect to its 2% general partner interest and common units.

***If distributions on our Class A shares are not paid with respect to any fiscal quarter, our Class A shareholders will not be entitled to receive that quarter s payments in the future.***

Our distributions to our Class A shareholders are not cumulative. Consequently, if distributions on our Class A shares are not paid with respect to any fiscal quarter, our Class A shareholders will not be entitled to receive that quarter s payments in the future.

***The amount of cash that we and PAA distribute each quarter may limit our ability to grow.***

Because we distribute all of our available cash, our growth may not be as fast as the growth of businesses that reinvest their available cash to expand ongoing operations. In fact, because currently our cash flow is generated solely from distributions we receive from AAP, which are derived from AAP s direct and indirect partnership interests in PAA, our growth will initially be completely dependent upon PAA. The amount of distributions received by AAP is based on PAA s per unit distribution paid on each PAA common unit and the number of PAA common units outstanding. If we issue additional Class A shares or we were to incur debt or are required to pay taxes, the payment of distributions on those additional Class A shares, or interest on such debt or payment of such taxes could increase the risk that we will be unable to maintain or increase our cash distribution levels.

***Our rate of growth may be reduced to the extent we purchase equity interests from PAA, which will reduce the relative percentage of the cash we receive from the IDRs.***

Our business strategy includes, where appropriate, supporting the growth of PAA by making loans, purchasing equity interests or providing other forms of financial support to PAA to provide funding for the acquisition of a business or asset or for an internal growth project. To the extent we purchase equity interests from PAA that are not entitled to distributions or do not receive distributions at the same rates as the IDRs, the rate of our distribution growth may be reduced, at least in the short term, as less of our cash distributions will come from our ownership of IDRs, with respect to which distributions increase at a faster rate than PAA s common units and any similar equity interests PAA may issue in the future.

***Restrictions in AAP s and PAA s respective credit facilities could limit AAP s ability to make distributions to us, thereby limiting our ability to make distributions to our Class A shareholders.***

AAP s and PAA s respective credit facilities contain various operating and financial restrictions and covenants. AAP s and PAA s respective ability to comply with these restrictions and covenants may be affected by events beyond their control, including

Table of Contents

prevailing economic, financial and industry conditions. If AAP or PAA is unable to comply with these restrictions and covenants, any indebtedness under these credit facilities may become immediately due and payable and AAP s and PAA s respective lenders commitment to make further loans under these credit facilities may terminate. AAP or PAA might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, AAP s credit facility limits our ability to pay distributions to our Class A shareholders during an event of default or if an event of default would result from the distribution.

For more information regarding AAP s and PAA s credit facilities, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources. For information regarding risks related to PAA s credit facilities, please see Risks Related to PAA s Business The terms of PAA s indebtedness may limit its ability to borrow additional funds or capitalize on business opportunities. In addition, PAA s future debt level may limit its future financial and operating flexibility.

***Substantially all of AAP s assets, including the IDRs and its indirect 2% general partner interest in PAA, are pledged under AAP s credit facility.***

Substantially all of AAP s assets, including the IDRs and its indirect 2% general partner interest in PAA, are pledged as security under AAP s credit facility. AAP s credit facility contains customary and other events of default. Upon an event of default, the lenders under AAP s credit facility could foreclose on AAP s assets, including the IDRs and its indirect 2% general partner interest in PAA, which are the only assets from which our cash flows are derived. This would have a material adverse effect on our business, financial condition and results of operations.

***Our shareholders do not elect or have the power to remove our general partner and until certain conditions are met will not vote in the election of our general partner s directors. The Class B shareholders own a sufficient number of shares to allow them to prevent the removal of our general partner.***

Our shareholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business. The board of directors of our general partner, including our independent directors, have been designated and elected by the Legacy Owners or their designees. Our shareholders do not currently have the ability to elect our general partner or the members of the board of directors of our general partner. However, when the overall direct and indirect economic interest of the Legacy Owners and their permitted transferees in AAP falls below 40% (calculated as described below), subject to certain time and other limitations, which we refer to as a trigger date, our shareholders will have the right to elect certain of our general partner s directors. The 40% threshold referred to above will be calculated on a fully diluted basis that takes into account any Class A shares owned by the Legacy Owners and their affiliates and permitted transferees, assumes the exchange of all AAP Management Units for AAP units based on the applicable conversion factor and attributes the ownership of such AAP units to the Legacy Owners. However, as a result of our resulting governance arrangements, including a staggered board of directors, limitations on director nomination rights and the 20% voting limitation in our partnership agreement, it will be difficult for one or more of our shareholders to gain control of our general partner s board of directors. Moreover, a period of up to three years, in certain circumstances, may lapse between the occurrence of a trigger date and the first meeting of shareholders called to elect members of our board of directors.

In addition, if our Class A shareholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner. Our general partner may only be removed by vote of the holders of at least 66 2/3% of our outstanding shares (including both Class A and Class B shares). At December 31, 2013, the Legacy Owners owned 77.9% of our outstanding shares. This ownership level enables the Legacy Owners to prevent our general partner s removal.

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

***Our general partner may cause us to issue additional Class A shares or other equity securities, including equity securities that are senior to our Class A shares, or cause AAP to issue additional securities, in each case without shareholder approval, which may adversely affect our shareholders.***

Our general partner may cause us to issue an unlimited number of additional Class A shares or other equity securities of equal rank with the Class A shares, or cause AAP to issue additional securities, in each case without shareholder approval. In addition,

Table of Contents

we may issue an unlimited number of shares that are senior to our Class A shares in right of distribution, liquidation and voting. Except for Class A shares issued in connection with the exercise of an Exchange Right, which will result in the cancellation of an equivalent number of Class B shares and therefore have no effect on the total number of outstanding shares, the issuance of additional Class A shares or our other equity securities of equal or senior rank, or the issuance by AAP of additional securities, will have the following effects:

- each shareholder s proportionate ownership interest in us may decrease;
- the amount of cash available for distribution on each Class A share may decrease;
- the relative voting strength of each previously outstanding Class A share may be diminished;
- the ratio of taxable income to distributions may increase; and
- the market price of the Class A shares may decline.

***If PAA s unitholders remove PAA GP, AAP may be required to sell or exchange its indirect general partner interest and its IDRs and we would lose the ability to manage and control PAA.***

We currently manage our investment in PAA through our membership interest in GP LLC, the general partner of AAP. PAA s partnership agreement, however, gives unitholders of PAA the right to remove PAA GP upon the affirmative vote of holders of 66 2/3% of PAA s outstanding units. If PAA GP withdraws as general partner in compliance with PAA s partnership agreement or is removed as general partner of PAA where cause (as defined in PAA s partnership agreement) does not exist and a successor general partner is elected in accordance with PAA s partnership agreement, AAP could elect to receive cash in exchange for its 2% general partner interest and the IDRs (if then owned by AAP). If PAA GP withdraws in circumstances other than those described in the preceding sentence and a successor general partner is elected in accordance with PAA s partnership agreement, the successor general partner will have the option to purchase the 2% general partner interest and the IDRs (if then owned by AAP) for their fair market value. If PAA GP or the successor general partner do not exercise their options, PAA GP s interests would be converted into common units based on an independent valuation. In each case, PAA GP would also lose its ability to manage PAA.

In addition, if PAA GP is removed as general partner of PAA, we would face an increased risk of being deemed an investment company. Please read If in the future we cease to manage and control PAA, we may be deemed to be an investment company under the Investment Company Act of 1940.

***Shareholders may not have limited liability if a court finds that shareholder action constitutes control of our business.***

Under Delaware law, our shareholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our shareholders as a group to remove or replace our general partner, to approve some amendments to the partnership agreement or to take other action under our partnership agreement constituted participation in the control of our business. Additionally, the limitations on the liability of holders of limited partner interests for the liabilities of a limited partnership have not been clearly established in many jurisdictions.

Furthermore, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that, under some circumstances, a shareholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

***If in the future we cease to manage and control PAA, we may be deemed to be an investment company under the Investment Company Act of 1940.***

If we cease to indirectly manage and control PAA and are deemed to be an investment company under the Investment Company Act of 1940, we would either have to register as an investment company under the Investment Company Act of 1940, obtain exemptive relief from the SEC or modify our organizational structure or our contractual rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict the ability of PAA and us to borrow funds or engage in other transactions involving leverage, require us to add additional directors who are independent of us and our affiliates, and adversely affect the price of our Class A shares.

Table of Contents

***Our partnership agreement restricts the rights of shareholders owning 20% or more of our shares.***

Our shareholders voting rights are restricted by the provision in our partnership agreement generally providing that any shares held by a person or group that owns 20% or more of any class of shares then outstanding, other than our general partner, the Legacy Owners (or certain transferees in private, non-exchange transactions), their respective affiliates and persons who acquired such shares with the prior approval of our general partner s board of directors, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of our shareholders to call meetings or to acquire information about our operations, as well as other provisions limiting our shareholders ability to influence the manner or direction of our management. As a result, the price at which our Class A shares will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

***If PAA s general partner, which is owned by AAP, is not fully reimbursed or indemnified for obligations and liabilities it incurs in managing the business and affairs of PAA, its value, and, therefore, the value of our Class A shares, could decline.***

AAP, GP LLC and their affiliates may make expenditures on behalf of PAA for which PAA GP will seek reimbursement from PAA. Under Delaware partnership law, PAA GP has unlimited liability for the obligations of PAA, such as its debts and environmental liabilities, except for those contractual obligations of PAA that are expressly made without recourse to the general partner. To the extent PAA GP incurs obligations on behalf of PAA, it is entitled to be reimbursed or indemnified by PAA. If PAA is unable or unwilling to reimburse or indemnify PAA GP, PAA GP may be required to satisfy those liabilities or obligations, which would reduce AAP s cash flows to us.

***The price of our Class A shares may be volatile, and holders of our Class A shares could lose a significant portion of their investments.***

The market price of our Class A shares could be volatile, and our shareholders may not be able to resell their Class A shares at or above the price at which they purchased such Class A shares due to fluctuations in the market price of the Class A shares, including changes in price caused by factors unrelated to our operating performance or prospects or the operating performance or prospects of PAA. The following factors, among others, could affect our Class A share price:

- PAA s operating and financial performance and prospects and the trading price of its common units;
- the level of PAA s quarterly distributions and our quarterly distributions;
- quarterly variations in the rate of growth of our financial indicators, such as distributable cash flow per Class A share, net income and revenues;
- changes in revenue or earnings and distribution estimates or publication of research reports by analysts;

- speculation by the press or investment community;
- sales of our Class A shares by our shareholders;
- the exercise by the Legacy Owners of their exchange rights with respect to any retained AAP units;
- announcements by PAA or its competitors of significant contracts, acquisitions, strategic partnerships, joint ventures, securities offerings or capital commitments;
- general market conditions, including conditions in financial markets;
- changes in accounting standards, policies, guidance, interpretations or principles;
- adverse changes in tax laws or regulations;
- domestic and international economic, legal and regulatory factors related to PAA s performance; and
- other factors described in these Risk Factors.

***An increase in interest rates may cause the market price of our shares to decline.***

Like all equity investments, an investment in our Class A shares is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments such as publicly traded limited partnership interests. Reduced demand for our Class A shares resulting from investors seeking other more favorable investment opportunities may cause the trading price of our Class A shares to decline.

***Future sales of our Class A shares in the public market could reduce our Class A share price, and any additional capital raised by us through the sale of equity or convertible securities may have a dilutive effect on our shareholders.***

Subject to certain limitations and exceptions, holders of AAP units may exchange their AAP units (together with a corresponding number of Class B shares) for Class A shares (on a one-for-one basis, subject to customary conversion rate adjustments for equity splits and reclassification and other similar transactions) and then sell those Class A shares. We may also issue additional Class A shares or convertible securities in subsequent public or private offerings.

We cannot predict the size of future issuances of our Class A shares or securities convertible into Class A shares or the effect, if any, that future issuances and sales of our Class A shares will have on the market price of our Class A shares. Sales of substantial amounts of our Class A shares (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our Class A shares.

***The Legacy Owners hold a majority of the combined voting power of our Class A and Class B shares.***

At December 31, 2013, the Legacy Owners held approximately 77.9% of the combined voting power of our Class A and Class B shares. The Legacy Owners are entitled to act separately in their own respective interests with respect to their partnership interests in us, and collectively they currently have the ability to (i) determine the outcome of all matters requiring shareholder approval, including certain mergers and other material transactions and (ii) cause or prevent a change in the composition of our board of directors or a change in control of our company that could deprive our shareholders of an opportunity to receive a premium for their Class A shares as part of a sale of our company. So long as the Legacy Owners continue to own a significant amount of our outstanding shares, even if such amount is less than 50%, they will continue to be able to strongly influence all matters requiring shareholder approval, regardless of whether or not other shareholders believe that such matters are in their own best interests.

***If we or PAA fail to maintain an effective system of internal controls, our ability to accurately report our financial results or prevent fraud could be adversely affected. As a result, our shareholders could lose confidence in our financial reporting, which would harm our business and the trading price of our Class A shares.***

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a publicly traded partnership. We are required to comply with the SEC s rules implementing Sections 302 and 404 of the Sarbanes-Oxley Act of 2002, which require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting. Though we are required to disclose material changes made to our internal controls and procedures on a quarterly basis, we are not required to make our first annual assessment of our internal control over financial reporting pursuant to Section 404 until the year following the filing of this annual report with the SEC. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results will be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our Class A shares.

***A valuation allowance on our deferred tax asset could reduce our earnings.***

A deferred tax asset of approximately $1.1 billion was recorded on our books as a result of certain of the transactions that took place in connection with our initial public offering as well as with subsequent exchanges by Legacy Owners of AAP units and Class B shares into Class A shares. GAAP requires that a valuation allowance must be established for deferred tax assets when it is more likely than not that they will not be realized. We believe that the deferred tax asset we recorded at the time of our initial public offering and the deferred tax assets recorded related to subsequent Legacy Owner exchanges will be realized and that a valuation allowance is not required. However, if we were to determine that a valuation allowance was appropriate for our deferred tax asset, we would be required to take an immediate charge to earnings with a corresponding reduction of partners capital and increase in balance sheet leverage as measured by debt to total capitalization.

Table of Contents

***The New York Stock Exchange ( NYSE ) does not require a limited partnership like us to comply with certain of its corporate governance requirements.***

Because we are a limited partnership, the NYSE does not require our general partner to have a majority of independent directors on its board of directors or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, our shareholders do not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements. In addition, as a limited partnership we are not required to seek shareholder approval for issuances of Class A shares, including issuances in excess of 20% of our outstanding equity securities, or for issuances of equity to certain affiliates.

***We may incur liability as a result of our ownership of our and PAA s general partner.***

Under Delaware law, a general partner of a limited partnership is generally liable for the debts and liabilities of the partnership for which it serves as general partner, subject to the terms of any indemnification agreements contained in the partnership agreement and except to the extent the partnership s contracts are non-recourse to the general partner. As a result of our structure, we indirectly own and control the general partner of PAA and own a portion of our general partner s membership interests. Our percentage ownership of our general partner is expected to increase over time as the Legacy Owners exercise their exchange rights. To the extent the indemnification provisions in the applicable partnership agreement or non-recourse provisions in our contracts are not sufficient to protect us from such liability, we may in the future incur liabilities as a result of our ownership of these general partner entities.

**Risks Related to Conflicts of Interest**

Our existing organizational structure and the relationships among us, PAA, our respective general partners, the Legacy Owners and affiliated entities present the potential for conflicts of interest. Moreover, additional conflicts of interest may arise in the future among us and the entities affiliated with any general partner or similar interests we acquire or among PAA and such entities.

***Conflicts of interest may arise as a result of our organizational structure and the relationships among us, PAA, our respective general partners, the Legacy Owners and affiliated entities.***

Our partnership agreement defines the duties of our general partner (and, by extension, its officers and directors). Our general partner s board of directors or its conflicts committee will have authority on our behalf to resolve any conflict involving us and they have broad latitude to consider the interests of all parties to the conflict.

Conflicts of interest may arise between us and our shareholders, on the one hand, and our general partner and its owners and affiliated entities, on the other hand, or between us and our shareholders, on the one hand, and PAA and its unitholders, on the other hand. The resolution of these conflicts may not always be in our best interest or that of our shareholders.

***Our partnership agreement defines our general partner s duties to us and contains provisions that reduce the remedies available to our shareholders for actions that might otherwise be challenged as breaches of fiduciary or other duties under state law.***

Our partnership agreement contains provisions that substantially reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, the Legacy Owners, our affiliates or any limited partner. Examples include its right to vote membership interests in our general partner held by us, the exercise of its limited call right, its rights to transfer or vote any shares it may own, and its determination whether or not to consent to any merger or consolidation of our partnership or amendment to our partnership agreement;

- generally provides that our general partner will not have any liability to us or our shareholders for decisions made in its capacity as a general partner so long as it acted in good faith which, pursuant to our partnership agreement, requires a subjective belief that the determination, or other action or anticipated result thereof is in, or not opposed to, our best interests;

- generally provides that any resolution or course of action adopted by our general partner and its affiliates in respect of a conflict of interest will be permitted and deemed approved by all of our partners, and will not constitute a breach of our partnership agreement or any duty stated or implied by law or equity if the resolution or course of action in respect of such conflict of interest is:

Table of Contents

- approved by a majority of the members of our general partner s conflicts committee after due inquiry, based on a subjective belief that the course of action or determination that is the subject of such approval is fair and reasonable to us;

- approved by majority vote of our Class A shares and Class B shares (excluding shares owned by our general partner and its affiliates, but including shares owned by the Legacy Owners) voting together as a single class;

- determined by our general partner (after due inquiry) to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

- determined by our general partner (after due inquiry) to be fair and reasonable to us, which determination may be made taking into account the circumstances and the relationships among the parties involved (including our short-term or long-term interests and other arrangements or relationships that could be considered favorable or advantageous to us).

- provides that, to the fullest extent permitted by law, in connection with any action or inaction of, or determination made by, our general partner or the conflicts committee of our general partner s board of directors with respect to any matter relating to us, it shall be presumed that our general partner or the conflicts committee of our general partner s board of directors acted in a manner that satisfied the contractual standards set forth in our partnership agreement, and in any proceeding brought by any limited partner or by or on behalf of such limited partner or any other limited partner or our partnership challenging any such action or inaction of, or determination made by, our general partner, the person bringing or prosecuting such proceeding shall have the burden of overcoming such presumption; and

- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that such person s conduct was criminal.

***The Legacy Owners may have interests that conflict with holders of our Class A shares.***

At December 31, 2013, the Legacy Owners owned 77.9% of our outstanding shares and 77.9% of the AAP units. As a result, the Legacy Owners may have conflicting interests with holders of Class A shares. For example, the Legacy Owners may have different tax positions from us which could influence their decisions regarding whether and when to cause us to dispose of assets.

Furthermore, conflicts of interest could arise in the future between us, on the one hand, and the Legacy Owners, on the other hand, concerning among other things, a decision whether to modify or limit the IDRs in the future or potential competitive business activities or business opportunities. These conflicts of interest may not be resolved in our favor.

***If we are presented with business opportunities, PAA has the first right to pursue such opportunities.***

Pursuant to the administrative agreement, we have agreed to certain business opportunity arrangements to address potential conflicts with respect to business opportunities that may arise among us, our general partner, PAA, PAA GP, AAP and GP LLC. If a business opportunity is presented to us, our general partner, PAA, PAA GP, AAP or GP LLC, then PAA will have the first right to pursue such business opportunity. We 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 our general partner. Accordingly, the terms of the administrative agreement limit our ability to pursue business opportunities.

***Our general partner s affiliates and the Legacy Owners may compete with us.***

Our partnership agreement provides that our general partner will be restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership of interests in us. The restrictions contained in our general partner s limited liability company agreement are subject to a number of exceptions. Affiliates of our general partner and the Legacy Owners will not be prohibited from engaging in other businesses or activities that might be in direct competition with us except to the extent they compete using our confidential information.

Table of Contents

***Our general partner has a call right that may require our shareholders to sell their Class A shares at an undesirable time or price.***

If at any time more than 80% of our outstanding Class A shares and Class B shares on a combined basis (including Class A shares issuable upon the exchange of Class B shares) are owned by our general partner, the Legacy Owners (or certain transferees in private, non-exchange transactions) or their respective affiliates, our general partner will have the right (which it may assign to any of its affiliates, the Legacy Owners or us), but not the obligation, to acquire all, but not less than all, of the remaining Class A shares held by public shareholders at a price equal to the greater of (x) the current market price of such shares as of the date three days before notice of exercise of the call right is first mailed and (y) the highest price paid by our general partner, the Legacy Owners (or certain transferees in private, non-exchange transactions) or their respective affiliates for such shares during the 90 day period preceding the date such notice is first mailed. As a result, holders of our Class A shares may be required to sell such Class A shares at an undesirable time or price and may not receive any return of or on their investment. Class A shareholders may also incur a tax liability upon a sale of their Class A shares. At December 31, 2013, the Legacy Owners owned 77.9% of the Class A shares and Class B shares on a combined basis.

**Risks Related to PAA s Business**

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

PAA has 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 its 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;

- Despite the fact that PAA 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;

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

- PAA 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 PAA 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 PAA s projects may depend on the completion or success of third-party facilities over which PAA have no control.

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

Table of Contents

***PAA s 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 its results.***

Results from PAA s 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 PAA s results. A backwardated market (meaning that the price of crude oil for future deliveries is lower than current prices) has a positive impact on lease gathering margins because 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, PAA s results from its 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 PAA s results. Depending on the overall duration of these transition periods, how PAA has allocated its assets to particular strategies and the time length of its crude oil purchase and sale contracts and storage lease agreements, these transition periods may have either an adverse or beneficial effect on its 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 PAA s supply and logistics segment.

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

Some of PAA s operations involve risks of personal injury, property damage and environmental damage, which could curtail its operations and otherwise materially adversely affect its cash flow. Virtually all of PAA s operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes. The location of PAA s assets and its customers assets in the U.S. Gulf Coast region makes them particularly vulnerable to hurricane or tropical storm risk. 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 PAA s physical facilities and hackers may attack its electronic and computer systems.

If one or more of PAA s facilities, including electronic and computer systems, or any facilities or businesses that deliver products, supplies or services to PAA or that it relies on in order to operate its business, are damaged by severe weather or any other disaster, accident, catastrophe, terrorist attack or event, its 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 its operations, or which causes PAA to make significant expenditures not covered by insurance, could reduce its cash available for paying distributions to its partners and, accordingly, adversely affect its financial condition and the market price of its securities.

***If PAA does not make acquisitions or if it makes acquisitions that fail to perform as anticipated, its future growth may be limited.***

PAA s ability to grow its distributions depends in part on its ability to make acquisitions that result in an increase in operating surplus per unit. If PAA is unable to make such accretive acquisitions either because PAA is (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, PAA s future growth will be limited. As a result, PAA may not be able to complete the number or size of acquisitions that it has targeted internally or to continue to grow as quickly as it has historically.

In evaluating acquisitions, PAA generally prepares one or more financial cases based on a number of business, industry, economic, legal, regulatory, and other assumptions applicable to the proposed transaction. Although PAA expects 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 PAA s 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 PAA is able to timely and effectively integrate the underlying assets and such assets perform at or near the levels anticipated in its acquisition projections.

Table of Contents

***PAA s acquisition strategy involves risks that may adversely affect its business.***

Any acquisition involves potential risks, including:

- performance from the acquired businesses or assets that is below the forecasts PAA used in evaluating the acquisition;
- a significant increase in PAA s 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 PAA is not indemnified by a credit-worthy party, including liabilities arising from the operation of the acquired businesses or assets prior to PAA s acquisition;
- risks associated with operating in lines of business that are distinct and separate from PAA s 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 PAA s ability to achieve anticipated levels of cash flows from its acquisitions, realize other anticipated benefits and its ability to pay distributions to its partners or meet its debt service requirements.

***PAA s growth strategy requires access to new capital. Tightened capital markets or other factors that increase its cost of capital could impair its ability to grow.***

PAA continuously considers potential acquisitions and opportunities for organic growth projects. Acquisition transactions can be effected quickly, may occur at any time and may be significant in size relative to its existing assets and operations. PAA s ability to fund its capital projects and make acquisitions depends on whether it can access the necessary financing to fund these activities. Any limitations on its access to capital or increase in the cost of that capital could significantly impair its growth strategy. PAA s ability to maintain its targeted credit profile, including maintaining its credit ratings, could affect PAA s cost of capital as well as its ability to execute its growth strategy. In addition, a variety of factors beyond its control could impact the availability or cost of capital, including domestic or international economic conditions, changes in key benchmark interest rates, 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, PAA cannot be certain that funding for its 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, PAA may be unable to implement its development plans, enhance its 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 its revenues and results of operations.

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

PAA believes that, because of its strategic asset base and complementary business model, PAA 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 PAA is able to capture that benefit, however, is subject to numerous risks and uncertainties, including whether PAA will be able to maintain an attractive credit rating and continue to receive open credit from its suppliers and trade counterparties. PAA s 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 its borrowing costs, reduce its borrowing capacity and cause its counterparties to reduce the amount of open credit it receive from them. This could negatively impact PAA s ability to capitalize on market opportunities. For example, PAA s ability to utilize its crude oil storage capacity for merchant activities to capture contango market opportunities (meaning that the price of crude oil for future deliveries is higher than current prices) 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 PAA to finance the storage of the crude oil from the time it completes the purchase of the crude oil until the time it completes the sale of the crude oil.

Table of Contents

***PAA is exposed to the credit risk of its customers in the ordinary course of its business activities.***

Risks of nonpayment and nonperformance by customers are a significant consideration in PAA s business. Although PAA has credit risk management policies and procedures that are designed to mitigate and limit its exposure in this area, there can be no assurance that PAA has adequately assessed and managed the creditworthiness of its 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 PAA s cash flow and its ability to pay or increase its cash distributions to its partners.

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

***PAA s risk policies cannot eliminate all risks. In addition, any non-compliance with its risk policies could result in significant financial losses.***

Generally, it is PAA s policy to establish a margin for crude oil or other products it purchases 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, PAA seeks to maintain a position that is substantially balanced between purchases on the one hand, and sales or future delivery obligations on the other hand. PAA s 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 PAA s anticipated physical supply of crude oil or other products could expose it to risk of loss resulting from price changes. PAA is also exposed to basis risk when crude oil or other products are purchased against one pricing index and sold against a different index. Moreover, PAA is exposed to some risks that are not hedged, including risks on certain of its inventory, such as linefill, which must be maintained in order to transport crude oil on its pipelines. In an effort to maintain a balanced position, specifically authorized personnel can purchase or sell an aggregate limit of up to 860,000 barrels of crude oil, refined products and NGL. Although this activity is monitored independently by PAA s risk management function, it exposes PAA to risks within predefined limits and authorizations.

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

***PAA s 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 it to significant costs and liabilities.***

PAA s operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons, including crude oil, NGL and refined products, as well as PAA s 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. PAA s 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 its overall cost of doing business, including its capital costs to construct, maintain and upgrade equipment and facilities. For example, the adoption of legislation or regulatory programs to reduce emissions of greenhouse gases, including cap and trade programs, could require PAA 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 PAA to additional operational requirements and constraints, or claims of damages to property or persons resulting from its operations. The laws and regulations applicable to PAA s operations are subject to change and interpretation by the relevant governmental agency, including the possibility that exemptions it currently qualifies for may be modified or changed in ways that require PAA to incur significant additional compliance costs. Any such change or interpretation adverse to PAA could have a material adverse effect on its operations, revenues, expenses and profitability.

PAA has a history of incremental additions to the miles of pipelines it owns, both through acquisitions and internal growth projects. PAA has also increased its terminal and storage capacity and operate several facilities on or near navigable waters and domestic water supplies. Although PAA has implemented programs intended to maintain the integrity of its assets (discussed below), as it acquires additional assets it historically has observed an increase in the number of releases of liquid hydrocarbons into the environment. These releases expose PAA 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. PAA s 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 PAA s results of operations.

PAA currently devotes 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. PAA has also developed and implemented certain pipeline integrity measures that go beyond regulatory mandate. See Items 1 and 2 Business and Properties Regulation.

For 2014 and beyond, PAA will continue to focus on pipeline integrity management as a primary operational emphasis. In that regard, PAA has implemented programs intended to maintain the integrity of its assets, with a focus on risk reduction through testing, enhanced corrosion control, leak detection, and damage prevention. PAA has an internal review process pursuant to which it examines various aspects of its 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, PAA may elect (as a result of its own internal initiatives) to spend substantial sums to ensure the integrity of and upgrade its pipeline systems to maintain environmental compliance and, in some cases, PAA may take pipelines out of service if it believes the cost of upgrades will exceed the value of the pipelines. PAA 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.

***PAA s 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 its facilities, which can be negatively impacted by a variety of factors outside of its control.***

PAA s 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 its 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 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 PAA s facilities and other energy logistics assets.

For example, while advances in horizontal drilling and fracturing technology over the last several years have lead to increased oil and hydrocarbon production in North America, much of the incremental production is attributable to shale resource plays where production from wells decline very rapidly. As a result, a significant slow-down in the number of well completions, whether due to net wellhead prices falling below minimum required economic levels, reduced capital market access or increased capital costs for producers, adverse governmental or regulatory action or other factors, could lead to a significant decline in North American crude oil and hydrocarbon production. In turn, such a development could lead to reduced throughput on our pipelines and at our other facilities, which could have a material adverse effect on our business.

In addition, catastrophic accidents, such as the 2010 explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico and the resulting oil spill, could lead to increased governmental regulation of PAA s industry s operations in a number of areas, including health and safety, environmental, and licensing, any of which could restrict the supply of crude oil available for transportation and have a negative impact on its profitability.

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

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

Table of Contents

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

Demand for crude oil and other hydrocarbon products PAA handles 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 PAA s 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 PAA s operating results. Specifically, reduced demand in an area serviced by PAA s transportation systems will negatively affect the throughput on such systems. Although the negative impact may be mitigated or overcome by PAA s ability to capture differentials created by demand fluctuations, this ability is dependent on location and grade of crude oil, and thus is unpredictable.

Fluctuations in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products, 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 PAA handles or a reduction of the fees it charges for its services. Also, increased supply of NGL products could reduce the value of NGL PAA handles and reduce the margins realized by it.

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 PAA accesses for any of the reasons stated above could adversely affect demand for the services PAA provides as well as NGL prices, which could negatively impact its operating results.

***PAA s assets are subject to federal, state and provincial regulation. Rate regulation or a successful challenge to the rates PAA charges on its U.S. and Canadian pipeline systems may reduce the amount of cash it generates.***

PAA s 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. PAA is also subject to the Pipeline Safety Regulations of the DOT. PAA s intrastate pipeline transportation activities are subject to various state laws and regulations as well as orders of regulatory bodies.

For PAA s U.S. interstate common carrier liquids pipelines subject to FERC regulation under the ICA, shippers may protest its pipeline tariff filings, file complaints against its existing rates, or the FERC can investigate on its own initiative. Under certain circumstances, the FERC could limit PAA s ability to set rates based on its costs, or could order PAA to reduce its 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.

PAA s 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 PAA to change its rates, provide access to other shippers, or change its terms of service. A provincial authority could, on the application of a shipper or other interested party, investigate the tariff rates or PAA s terms and conditions of service relating to its provincially regulated proprietary pipelines. If it found PAA s 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 PAA to change its rates, provide access to other shippers, or otherwise alter its terms of service. Any reduction in PAA s tariff rates would result in lower revenue and cash flows.

Table of Contents

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

PAA s cross border activities subject it 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.

***PAA s sales of oil, natural gas, NGL and other energy commodities, and related transportation and hedging activities, expose it to potential regulatory risks.***

The FTC, the FERC and the Commodity Futures Trading Commission hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to PAA s physical sales of oil, natural gas, NGL or other energy commodities, and any related transportation and/or hedging activities that it undertakes, PAA is required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. PAA s sales may also be subject to certain reporting and other requirements. Additionally, to the extent that PAA enters into transportation contracts with natural gas pipelines that are subject to FERC regulation, it is subject to FERC requirements related to the use of such capacity. Any failure on PAA s part to comply with the regulations and policies of the FERC, the FTC or the Commodity Futures Trading Commission 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 PAA s business, results of operations, financial condition and its ability to make cash distributions to its partners.

***The enactment and implementation of derivatives legislation could have an adverse impact on PAA s ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with its 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 PAA, 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 PAA 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 PAA, 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. PAA does not utilize credit default swaps and PAA qualifies and expects to continue to qualify for the end-user exception from the mandatory clearing requirements for swaps entered into to hedge its interest rate risks.  Should the CFTC designate commodity derivatives for mandatory clearing, PAA would expect to qualify for an end-user exception from the mandatory clearing requirements for swaps entered into to hedge its commodity price risk.  However, the majority of PAA s 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 PAA s liquidity (defined as unrestricted cash on hand plus available capacity under its credit facilities) and reduce PAA s ability to use cash for capital expenditures or other partnership purposes. A requirement to post additional cash margin or collateral could therefore reduce PAA s ability to execute hedges necessary to reduce commodity price exposures and protect cash flows. PAA could be at risk for reduced liquidity if the CFTC adopts rules and definitions that require companies, such as PAA, to post collateral for its uncleared derivative hedging activities. The proposed margin rules for uncleared swaps are not yet final and, therefore, the impact of such rules on PAA is uncertain at this time.

Even if PAA itself is not required to post additional cash margin or collateral for its derivative contracts, the banks and other derivatives dealers who are PAA s 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 PAA, thus decreasing the benefits to PAA of hedging transactions or reducing its profitability.  The Dodd Frank Act also may require the counterparties to PAA s derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. In addition, implementation of the Dodd Frank Act and related rules and regulations could reduce

Table of Contents

the overall liquidity and depth of the markets for financial and other derivatives PAA utilizes in connection with its business, which could expose PAA to additional risks or limit the opportunities PAA is able to capture by limiting the extent to which PAA is able to execute its 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. PAA s financial results could be adversely affected if a consequence of the Dodd Frank Act and implementing regulations is to reduce the volatility of commodity prices.

The full impact of the Dodd Frank Act and related regulatory requirements upon PAA s 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 PAA encounters, reduce PAA s ability to monetize or restructure its existing derivative contracts or increase PAA s exposure to less creditworthy counterparties. If PAA reduces its use of derivatives as a result of the Dodd Frank Act and regulations implementing the Dodd Frank Act, PAA s results of operations may become more volatile and its cash flows may be less predictable. Any of these consequences could have a material adverse effect on PAA, its financial condition and its results of operations.

***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. 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 PAA s transportation, terminalling and storage services as well as its supply and logistics services.

***PAA may not be able to compete effectively in its transportation, facilities and supply and logistics activities, and PAA s business is subject to the risk of a capacity overbuild of midstream energy infrastructure in the areas where it operates.***

PAA faces competition in all aspects of its business and can give no assurances that it will be able to compete effectively against its 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, organic growth projects, acquisitions and joint venture activities. Some of PAA s competitors have capital resources many times greater than PAA s and control greater supplies of crude oil, natural gas or NGL.

A significant driver of competition in some of the markets where PAA operates (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 PAA, it is 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 PAA 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, PAA also faces 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 PAA experiences a significant capacity overbuild in one or more of the areas where it operates, it could have a significant adverse impact on PAA s financial position, cash flows and ability to pay or increase distributions to its unitholders.

With respect to PAA s crude oil activities, its 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. PAA competes 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 PAA s natural gas storage operations, the principal elements of competition are rates, terms of service, supply and market access and flexibility of service. PAA s 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 PAA s facilities.

With regard to PAA s NGL operations, it competes with large oil, natural gas and natural gas liquids companies that may, relative to PAA, 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.

Table of Contents

***PAA 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 PAA s 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, PAA can give no assurance that it will be able to maintain adequate insurance in the future at rates or on other terms PAA considers commercially reasonable. In addition, although PAA believes that it currently maintains adequate insurance coverage, insurance will not cover many types of interruptions or events that might occur and will not cover all risks associated with its 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 PAA s financial position, results of operations and cash flows.

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

As of December 31, 2013, PAA s consolidated debt outstanding was approximately $7.8 billion, consisting of approximately $6.7 billion principal amount of long-term debt (including senior notes) and approximately $1.1 billion of short-term borrowings. As of December 31, 2013, PAA had over $1.8 billion of available borrowing capacity under its senior unsecured revolving credit facility and its senior secured hedged inventory facility.

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

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

- credit rating agencies may view PAA s debt level negatively;

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

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

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

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

PAA s 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 PAA s 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 its assets or enter into a merger or consolidation. PAA s credit facility treats a change of control as an event of default and also requires PAA to maintain a certain debt coverage ratio. PAA s senior notes do not restrict distributions to unitholders, but a default under its credit agreements will be treated as a default under the senior notes. Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Facilities and Indentures.

PAA s ability to access capital markets to raise capital on favorable terms will be affected by its debt level, its operating and financial performance, the amount of its current maturities and debt maturing in the next several years, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade PAA s credit ratings, then it could experience an increase in its borrowing costs, face difficulty accessing capital markets or incurring additional indebtedness, be unable to receive open credit from its 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 its common units. If PAA is unable to access the capital markets on favorable terms at the time a debt obligation becomes due in the future, it might be forced to refinance some of its 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 PAA 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 PAA s leverage may adversely affect its future financial and operating flexibility and thereby impact its ability to pay cash distributions at expected rates.

Table of Contents

***Increases in interest rates could adversely affect PAA s business.***

As of December 31, 2013, PAA had approximately $7.8 billion of consolidated debt, of which approximately $6.7 billion was at fixed interest rates and approximately $1.1 billion was at variable interest rates. PAA is exposed to market risk due to the short-term nature of its commercial paper borrowings and the floating interest rates on its credit facilities. PAA s 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 PAA s supply and logistics segment results by increasing interest costs associated with the storage of hedged crude oil and NGL inventory.

***Changes in currency exchange rates could adversely affect PAA s operating results.***

Because PAA is a U.S. dollar reporting company and also conduct operations in Canada, it is exposed to currency fluctuations and exchange rate risks that may adversely affect the U.S. dollar value of its earnings, cash flow and partners capital under applicable accounting rules.

***An impairment of goodwill or intangibles could reduce PAA s earnings.***

At December 31, 2013, PAA had approximately $2.5 billion of goodwill and approximately $420 million of intangibles. 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 PAA to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. GAAP requires that PAA amortizes finite-lived intangibles over their estimated useful lives and test all of its intangibles for impairment when events or circumstances indicate the carrying value may not be recoverable. If PAA was to determine that any of its goodwill or intangibles were impaired, PAA would be required to take an immediate charge to earnings with a corresponding reduction of partners capital and increase in balance sheet leverage as measured by debt to total capitalization.

***Marine transportation of crude oil has inherent operating risks.***

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

***PAA is dependent on use of third-party assets for certain of its operations.***

Certain of PAA s business activities require the use of third-party assets over which it may have little or no control. For example, a portion of PAA s 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 PAA s access to this dock was denied, and if access to an alternative dock could not be arranged, the volume of crude oil that it presently receives from its 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 PAA s leased rail cars, could significantly reduce its profitability due fixed costs incurred to obtain the right to use such assets.***

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

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

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

a failure on the part of PAA s storage facilities to perform as expected, whether due to malfunction of equipment or facilities or realization of other operational risks;

a failure on PAA s part to create incremental storage capacity at its facilities due to reduced leaching rates, operational or other factors;

the operating pressure of PAA s 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 PAA makes from time to time in connection with the management and operation of its storage facilities. Examples include, without limitation, decisions with respect to matters such as (i) the aggregate amount of commitments PAA is willing to make with respect to wheeling, injection, and withdrawal services, which could exceed PAA s 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 PAA conducts leaching activities at its facilities in connection with the creation of new salt caverns or the expansion of existing caverns, which can impact the amount of storage capacity PAA has available to satisfy its customers requests, (iv) the timing and aggregate volume of any base gas park and/or loan transactions PAA consummates, which can directly affect the operating pressure of PAA s storage facilities and (v) the amount of compression capacity and other gas handling equipment that PAA installs at its 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 PAA manages and monitors all of these various factors in connection with the ongoing operation of its natural gas storage facilities with the goal of performing all of its contractual commitments and obligations and optimizing revenue, one or more of the above factors may adversely impact PAA s ability to satisfy its injection, withdrawal or wheeling obligations under its storage contracts. In such event, PAA may be liable to its customers for losses or damages they suffer and/or PAA may need to incur costs or expenses in order to permit it to satisfy its obligations.

***Cost reimbursements due to PAA s general partner may reduce PAA s cash available for distribution to its partners.***

Prior to making any distribution to its partners, PAA will reimburse PAA GP and its affiliates, including officers and directors, for all expenses incurred on PAA s behalf (other than expenses related to the AAP Management Units). The reimbursement of expenses and the payment of fees could adversely affect PAA s ability to make distributions to its partners. PAA GP has sole discretion to determine the amount of these expenses. In addition, PAA GP and its affiliates may provide PAA with services for which PAA will be charged reasonable fees as determined by its general partner.

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

Because distributions on PAA s partnership interests are dependent on the amount of cash it generates, distributions to PAA s common unitholders may fluctuate based on PAA s performance, which will result in fluctuations in the amount of distributions ultimately received by AAP. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond PAA s control and the control of PAA GP. 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 PAA records losses and might not be made during periods when it records profits.

**Tax Risks**

As our only cash-generating assets consist of our partnership interest in AAP and its related direct and indirect interests in PAA, our tax risks are primarily derivative of the tax risks associated with an investment in PAA.

***The tax treatment of PAA depends on its status as a partnership for U.S. federal income tax purposes, as well as it not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service ( IRS ) were to treat PAA as a corporation or PAA becomes subject to additional amounts of entity-level taxation for state or foreign tax purposes, it would reduce the amount of cash available for distribution to us and increase the portion of our distributions treated as taxable dividends.***

At December 31, 2013, we owned a 22.1% limited partner interest in AAP, which indirectly owns PAA s 2% general partner interest, and directly owns all of PAA s IDRs. Accordingly, the value of our indirect investment in PAA, as well as the anticipated after-tax economic benefit of an investment in our Class A shares, depends largely on PAA being treated as a partnership for federal income tax purposes, which requires that 90% or more of PAA s gross income for every taxable year consist of qualifying income, as defined in Section 7704 of the Internal Revenue Code of 1986, as amended (the Code ).

Despite the fact that PAA is a limited partnership under Delaware law and, unlike us, has not elected to be treated as a corporation for federal income tax purposes, it is possible, under certain circumstances, for PAA to be treated as a corporation for federal income tax purposes. Although we do not believe, based on its current operations, that PAA will be so treated, a change in PAA s business could cause it to be treated as a corporation for federal income tax purposes or otherwise subject it to federal income taxation as an entity.

Current law may change, causing PAA to be treated as a corporation for federal income tax purposes or otherwise subjecting PAA to 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, PAA is subject to entity-level tax on the portion of its income apportioned to Texas in the prior year. Imposition of any similar taxes on PAA in additional states will reduce its cash available for distribution to its partners.

If PAA were treated as a corporation for federal income tax purposes, it would pay federal income tax on its 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 PAA s partners, including AAP, would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to PAA s partners. Because a tax would be imposed upon PAA as a corporation, its cash available for distribution would be substantially reduced. Therefore, treatment of PAA as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to us, likely causing a substantial reduction in the value of our Class A shares.

PAA s partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects PAA to taxation as a corporation or otherwise subjects PAA to entity-level taxation for federal income tax purposes, PAA s 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 without the specific details of any such new law or modification, in such event, it is likely the amount of distributions AAP receives from PAA and our resulting cash flows could be reduced substantially, which would adversely affect our ability to pay distributions to our shareholders.

Moreover, if PAA were treated as a corporation we would not be entitled to the deductions associated with our initial acquisition of interests in AAP or subsequent exchanges of retained AAP interests and Class B shares for our Class A shares. As a result, if PAA were treated as a corporation, (i) our liability for taxes would likely be higher, further reducing our cash available for distribution, and (ii) a greater portion of the cash we are able to distribute will be treated as a taxable dividend.

***The tax treatment of publicly traded partnerships such as PAA 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 PAA, may be modified by administrative, legislative or judicial changes, or differing interpretations at any time. Any modifications to the U.S. federal income tax laws that may be applied retroactively or prospectively could make it more difficult or impossible to meet the expectation of future cash distributions or reduce the cash available for distributions to our shareholders. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Currently, one such legislative proposal would eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which PAA relies for its treatment as a partnership for U.S. federal income tax purposes. PAA is unable to predict whether any of these changes or other proposals will be reintroduced or ultimately will be enacted. Any such changes could negatively impact the value of our indirect investment in PAA. Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes.

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

PAA 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 its 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. PAA s termination would, among other things, result in the closing of its taxable year for all unitholders, which would result in PAA filing two tax returns for one fiscal year and could result in a deferral of depreciation deductions allowable in computing PAA s taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of PAA s taxable year may also result in more than twelve months of PAA s taxable income or loss being includable in his taxable income for the year of termination. PAA s termination currently would not affect its classification as a partnership for federal income tax purposes, but it would result in PAA being treated as a new partnership for tax purposes. If PAA were treated as a new partnership, PAA would be required to make new tax elections and could be subject to penalties if it was 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.

***Taxable gain or loss on the sale of our Class A shares could be more or less than expected.***

If a holder sells our Class A shares, the holder will recognize a gain or loss equal to the difference between the amount realized and the holder s tax basis in those Class A shares. To the extent that the amount of our distributions exceeds our current and accumulated earnings and profits, the distributions will be treated as a tax free return of capital and will reduce a holder s tax basis in the Class A shares. We do not expect to have any earnings and profits for an extended period of time, which we estimate will include, at a minimum, each of the periods ending December 31, 2014, 2015, and 2016, Because our distributions in excess of our earnings and profits decrease a holder s tax basis in Class A shares, such excess distributions will result in a corresponding increase in the amount of gain, or a corresponding decrease in the amount of loss, recognized by the holder upon the sale of the Class A shares. Please read Summary of Tax Considerations Gain on Disposition of Class A Shares for a further discussion of the foregoing.

***Our current tax treatment may change, which could affect the value of our Class A shares or reduce our cash available for distribution.***

Our expectation that our initial acquisition of interests in AAP will result in deductions that will offset a substantial portion of our taxable income for an extended period of time following the closing of this offering and that such deductions will also result in our distributions not constituting taxable dividends for an extended period of time thereafter is based on current law with respect to the amortization of basis adjustments associated with our acquisition of interests in AAP. Similarly, our expectation that exchanges by the Legacy Owners of their retained interests in AAP and Class B shares in us for our Class A shares in the future will result in additional tax deductions is based on current law with respect to such exchanges. Changes in federal income tax law relating to such tax treatment could result in (i) our being subject to additional taxation at the entity level with the result that we would have less cash available for distribution, and (ii) a greater portion of our distributions being treated as taxable dividends. Moreover, we are subject to tax in numerous jurisdictions. Changes in current law in these jurisdictions, particularly relating to the treatment of deductions attributable to acquisitions of interests in AAP, could result in our being subject to additional taxation at the entity level with the result that we would have less cash available for distribution.

***Any decrease in our Class A share price could adversely affect our amount of cash available for distribution.***

Changes in certain market conditions may cause our Class A share price to decrease. If our Legacy Owners exchange their retained interests in AAP and Class B shares in us for our Class A shares at a point in time when our Class A share price is below the price at which Class A shares were sold in our initial public offering or in any subsequent exchange, the ratio of our income tax deductions to gross income would decline. This decline could result in our being subject to tax sooner than expected, our tax liability being greater than expected, or a greater portion of our distributions being treated as taxable dividends.

***The IRS Forms 1099-DIV that our shareholders receive from their brokers may over-report dividend income with respect to our shares for U.S. federal income tax purposes, and failure to report dividend income in a manner consistent with the IRS Forms 1099-DIV may cause the IRS to assert audit adjustments to a shareholder s U.S. federal income tax return. For non-U.S. holders of our shares, brokers or other withholding agents may overwithhold taxes from dividends paid, in which case a shareholder generally would have to timely file a U.S. tax return or an appropriate claim for refund in order to claim a refund of the overwithheld taxes.***

Distributions we pay with respect to our shares will constitute dividends for U.S. federal income tax purposes only to the extent of our current and accumulated earnings and profits. Distributions we pay in excess of our earnings and profits will not be treated as dividends for U.S. federal income tax purposes; instead, they will be treated first as a tax-free return of capital to the extent of a shareholder s tax basis in their shares and then as capital gain realized on the sale or exchange of such shares. We may be unable to timely determine the portion of our distributions that is a dividend for U.S. federal income tax purposes.

For a U.S. holder of our shares, the IRS Forms 1099-DIV may not be consistent with our determination of the amount that constitutes a dividend for U.S. federal income tax purposes or a shareholder may receive a corrected IRS Form 1099-DIV (and may therefore need to file an amended federal, state or local income tax return). We will attempt to timely notify our shareholders of available information to assist with income tax reporting (such as posting the correct information on our website). However, the information that we provide to our shareholders may be inconsistent with the amounts reported by a broker on IRS Form 1099-DIV, and the IRS may disagree with any such information and may make audit adjustments to a shareholder s tax return.

For a non-U.S. holder of our shares, dividends for U.S. federal income tax purposes will be subject to withholding of U.S. federal income tax at a 30% rate (or such lower rate as may be specified by an applicable income tax treaty) unless the dividends are effectively connected with conduct of a U.S. trade or business. Please read Summary of Tax Considerations Consequences to Non-U.S. Holders. In the event that we are unable to timely determine the portion of our distributions that is a dividend for U.S. federal income tax purposes, or a shareholder s broker or withholding agent chooses to withhold taxes from distributions in a manner inconsistent with our determination of the amount that constitutes a dividend for such purposes, a shareholder s broker or other withholding agent may overwithhold taxes from distributions paid. In such a case, a shareholder generally would have to timely file a U.S. tax return or an appropriate claim for refund in order to obtain a refund of the overwithheld tax.

Table of Contents

**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.

*Pemex Exploración y Producción v. Big Star Gathering Ltd L.L.P. et al.* In two cases filed in the Texas Southern District Court in May 2011 and April 2012, Pemex Exploración y Producción ( PEP ) alleges that certain parties stole condensate from pipelines and gathering stations and conspired with U.S. companies (primarily in Texas) to import and market the stolen condensate. PEP does not allege that Plains was part of any conspiracy, but that it dealt in the condensate only after it had been obtained by others and resold to Plains Marketing, L.P. PEP seeks actual damages, attorney s fees, and statutory penalties from Plains Marketing, L.P. In February 2013, the Court granted Plains Marketing, L.P. s motion to be dismissed from the April 2012 lawsuit. In October 2013, the Court issued an order in the May 2011 lawsuit granting summary judgment in favor of Plains Marketing, L.P. with respect to all of PEP s remaining claims against Plains Marketing, L.P. In February 2014, the Court affirmed its order granting summary judgment in favor of Plains Marketing, L.P., denied PEP s motion for reconsideration, and issued a judgment dismissing all claims against Plains. PEP has the right to appeal such rulings.

*PNG Merger*. Purported class action lawsuits were filed on behalf of PNG unitholders challenging the PNG Merger. Two lawsuits were filed in the Delaware Court of Chancery in September 2013 and were consolidated under the caption In re PAA Natural Gas Storage, Limited Partnership Unitholder Litigation, C.A. No. 8908-VCL (which we refer to as the Consolidated Delaware Action). Two lawsuits were filed in Texas state court in September 2013 and were consolidated under the caption Vicars v. PNGS GP, LLC, et al., Cause No. 2013-52687 (Tex. Dist. Ct. Harris County) (which we refer to as the Consolidated Texas Action). Four lawsuits were filed in Texas federal court in October 2013 and were consolidated under the caption The DuckPond Trust, et al., v. PAA Natural Gas Storage, LP., et al., 4:13-cv-03170 (S.D. Tex.) (which we refer to as the Consolidated Federal Action).

Plaintiffs in the Consolidated Delaware Action generally allege that (i) the individual defendants breached fiduciary duties owed to PNG unitholders by allegedly approving the merger agreement at an unfair price and through an unfair process and by agreeing to certain deal protection devices; and (ii) the PNG Merger unfairly benefits certain members of PNG s board of directors. Plaintiffs also allege that PNG s general partner, PNG and other of our affiliates aided and abetted the alleged fiduciary breaches by the individual defendants.

Plaintiffs in the Consolidated Texas Action generally allege that (i) the individual defendants breached their duties owed to PNG s unitholders under PNG s partnership agreement as well as the implied covenant of good faith and fair dealing, and are engaging in self-dealing; and (ii) PNG s general partner, PNG and other of our affiliates have aided and abetted the defendant directors for the purpose of advancing their own interests and/or assisting such directors in connection with their breaches of their respective duties. In addition, the Consolidated Texas Action includes purported derivative claims on behalf of PNG based on the alleged breaches of duties by the individual defendants.

In February 2014, the Consolidated Federal Action was dismissed. Plaintiffs in the remaining actions generally seek, among other relief, to enjoin the transaction, rescission in the event the transaction is consummated, an order directing defendants to account to plaintiff and other members of the putative class for all damages caused by their breaches, money damages and an award of costs and disbursements, including reasonable attorneys fees. We cannot predict the outcome of these or any other lawsuits that might be filed, nor can we predict the amount of time and expense that will be required to resolve these lawsuits. We intend to defend vigorously against these and any other actions. See Note 1 to our Consolidated Financial Statements for a description of the PNG Merger.

Table of Contents

***Environmental***

**General**

Although we believe that our efforts to enhance our leak prevention and detection capabilities have produced positive results, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline and storage operations. 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, 2013, our estimated undiscounted reserve for environmental liabilities totaled approximately $93 million, of which approximately $11 million was classified as short-term and approximately $82 million was classified as long-term. At December 31, 2012, our reserve for environmental liabilities totaled approximately $96 million, of which approximately $13 million was classified as short-term and approximately $83 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, 2013 and 2012, we had recorded receivables totaling approximately $10 million and $42 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 to five years. Our estimates used in these reserves are based on information currently available to us and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional 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.

**Rainbow Pipeline Release**

During April 2011, we experienced a crude oil release of approximately 28,000 barrels of crude oil on a remote section of our Rainbow Pipeline located in Alberta, Canada. Since the release and through December 31, 2013, we spent approximately $70 million, before insurance recoveries, in connection with site clean-up, reclamation and remediation activities, and as of December 31, 2013, we did not have any material outstanding liabilities or insurance receivables relating to this release. On February 26, 2013, the AER issued a report detailing four enforcement actions against PMC for failure to comply with certain regulatory requirements in connection with the release, including requirements related to operations and maintenance procedures, leak detection and response, backfill and compaction procedures and emergency response plan testing. PMC is in the process of taking appropriate actions necessary to respond to and comply with the enforcement actions set forth in the report, including the implementation of additional risk assessment procedures and the taking of other actions designed to minimize the risk that similar incidents occur in the future and enhance the effectiveness of PMC s response to any such future incidents. In addition, on April 23, 2013, the Alberta Crown Prosecutor filed civil charges under the Environmental Protection and Enhancement Act against PMC relating to the release. To date, PMC has not been assessed any fines or penalties related to this release; however, such fines or penalties may be assessed in the future and are not expected to be material.

**Rangeland Pipeline Release**

During June 2012, we experienced a crude oil release on a section of our Rangeland Pipeline located near Sundre, Alberta, Canada. Approximately 3,000 barrels were released into the Red Deer River and were contained downstream in the Gleniffer Reservoir. Remediation activities in the reservoir area were completed by June 30, 2012, remediation of the remaining impacted areas of government-owned lands was completed by September 30, 2012 and interim closure, in respect of those lands, was received from the applicable regulatory agencies. Monitoring will continue into 2014, and a long-term monitoring plan has been developed and implemented in accordance with regulatory requirements. Through December 31, 2013, we spent approximately $46 million, before insurance recoveries, in connection with site clean-up, reclamation and remediation activities. This release is currently under investigation by the AER, which also intends to perform an audit of PMC s operations. Although the AER s final investigation is not

Table of Contents

complete, on July 4, 2013, the AER issued four enforcement actions against PMC citing failure to inspect water crossings, failure to complete an engineering assessment to determine suitability of continued operation of the Rangeland Pipeline, failure to maintain updated emergency response plans, and failure to conduct regular public awareness programs. To date, no fines or penalties have been assessed against PMC with respect to this release; however, it is possible that fines or penalties may be assessed against PMC in the future and are not expected to be material.

**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 oil was contained within our pipeline right of way, but some of the released 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, and we may be subjected to a civil penalty. The aggregate cost to clean up and remediate the site was approximately $6 million, which has been recognized in Field operating costs on our Consolidated Statement of Operations.

**Kemp River Pipeline Release**

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. We estimate that the aggregate clean-up and remediation costs associated with these releases will be approximately $15 million which we have recognized in Field operating costs on our Consolidated Statement of Operations.

***Insurance***

A pipeline, terminal or other facility may experience damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain 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 public 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.

In 2011, we elected not to renew our hurricane insurance, and, instead, to self-insure this risk. Our assessment of the current availability of coverage and associated rates has led us to the decision to continue to self-insure. This decision does not affect our third-party liability insurance, which still covers hurricane-related liability claims which we have renewed 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 Shares, Related Shareholder Matters and Issuer Purchases of Equity Securities*

Our Class A shares are listed and traded on the New York Stock Exchange ( NYSE ) under the symbol PAGP. As of February 20, 2014, there were approximately 18,100 record holders and beneficial owners (held in street name). As of March 6, 2014, there were 135,833,637 Class A shares outstanding and the closing market price for our Class A shares was $28.04 per share.

The following table sets forth high and low sales prices for our Class A shares and the cash distribution declared per Class A share for the periods indicated:

| | Class A share Price Range | | |
|---|---|---|---|
| | **High** | **Low** | **Cash Distribution (1) (2)** |
| 4th Quarter 2013 (3) | $ 27.04 | $ 21.50 | $ 0.12505 |

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

(2) The distribution paid for the fourth quarter of 2013 was prorated for the period from October 21, 2013 (the date of closing of our IPO) through December 31, 2013, which corresponds to a distribution of $0.15979 per Class A share before proration, assuming our ownership of AAP for the full fourth quarter of 2013.

(3) Our Class A shares did not commence trading on the NYSE until October 2013.

Our Class B shares are not listed or traded on any stock exchange.

Our Class A shares may be used as a form of compensation to our employees and directors. Additional information regarding our equity compensation plans is included in Part III of this report under Item 13. Certain Relationships and Related Transactions, and Director Independence.

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

**Use of Proceeds from Sale of Securities**

On October 16, 2013, we commenced the IPO of our Class A shares pursuant to our Registration Statement on Form S-1, Commission File No. 333-190227, which was declared effective by the Securities and Exchange Commission on October 15, 2013. Barclays Capital Inc., Goldman, Sachs & Co., JP Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., UBS Securities LLC and Wells Fargo Securities, LLC acted as joint book-running managers of the offering.

In October 2013, we issued 132,382,094 Class A shares, which included 4,382,094 Class A shares issued pursuant to partial exercise of the underwriters over-allotment option, at a price per share of $22.00. After deducting underwriting discounts and commissions of approximately $87 million paid to the underwriters, estimated offering expenses of approximately $5 million, the net proceeds from the IPO were approximately $2.8 billion. We distributed all of the net proceeds to the existing owners of AAP who sold a portion of their interests in AAP in connection with the offering.

Table of Contents

**Cash Distribution Policy**

Our partnership agreement requires that, within 55 days after the end of each quarter, we distribute all of our available cash to Class A shareholders of record on the applicable record date. Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the date of determination of available cash for the distribution in respect of such quarter (including expected distributions from AAP in respect of such quarter), less the amount of cash reserves established by our general partner, which will not be subject to a cap, to:

- comply with applicable law or any agreement binding upon us or our subsidiaries (exclusive of PAA and its subsidiaries);
- provide funds for distributions to shareholders;
- provide for future capital expenditures, debt service and other credit needs as well as any federal, state, provincial or other income tax that may affect us in the future;
- permit us to pay a ratable amount to AAP as necessary to permit AAP to make required capital contributions to PAA to maintain PAA GP s 2% general partner interest upon the issuance of additional partnership securities by PAA; or
- provide for the proper conduct of our business;

As of December 31, 2013, our only cash-generating assets consisted of 133,833,637 AAP units, which represent a 22.1% limited partner interest in AAP. AAP currently receives all of its cash flows from its direct ownership of all of PAA s incentive distribution rights and its indirect ownership of the 2% general partner interest in PAA. Therefore, our cash flow and resulting ability to make distributions will be completely dependent upon the ability of PAA to make distributions to AAP in respect of those partnership interests. The actual amount of cash that PAA, and correspondingly AAP, will have available for distribution will primarily depend on the amount of cash PAA generates from its operations. Also, under the terms of the agreements governing AAP and PAA s debt, they 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, PAA Commercial Paper Program and Indentures.

Although not required to do so, in response to past requests by PAA management in connection with PAA s acquisition activities, AAP 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 PAA s 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 PAA s limited partners and the holders of its general partner interest and IDRs. AAP agreed to reduce the amount of its incentive distribution by $3.75 million per quarter for distributions paid during 2013, $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 the BP NGL Acquisition and the completion of the PNG Merger on

December 31, 2013. See Note 3 to our Consolidated Financial Statements for further discussion of the BP NGL Acquisition. See Note 1 to our Consolidated Financial Statements for further discussion of the PNG Merger.

**Issuer Purchases of Equity Securities**

We did not repurchase any of our Class A shares during the fourth quarter of 2013, and we do not have any announced or existing plans to repurchase any of our Class A shares.

Table of Contents

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

The following tables set forth selected historical consolidated financial and other information for PAGP as of the dates and for the periods indicated. The selected consolidated statements of operations data for the year ended December 31, 2013 include results attributable to PAGP from October 21, 2013 (the date of closing PAGP s IPO) through December 31, 2013, plus results for Plains All American GP LLC ( GP LLC ), the predecessor entity to PAGP, prior to October 21, 2013.

The selected historical statements of operations and cash flow data for the years ended December 31, 2013, 2012 and 2011 and balance sheet data as of December 31, 2013 and 2012 is derived from the audited financial statements of PAGP (and GP LLC as discussed above) included elsewhere in this document. The selected historical statements of operations and cash flow data for the year ended December 31, 2010 and 2009 and the balance sheet data as of December 31, 2011, 2010 and 2009 are derived from the unaudited financial statements of GP LLC that are not included elsewhere in this document.

The selected financial data should be read in conjunction with the Consolidated Financial Statements, including the notes thereto, and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

| | Year Ended December 31, (in millions, except for per share data) | | | | |
|---|---|---|---|---|---|
| | **2013** | **2012** | **2011** | **2010** | **2009** |
| **Statement of operations data:** | | | | | |
| Total revenues | $ 42,249 | $ 37,797 | $ 34,275 | $ 25,893 | $ 18,520 |
| Net income | $ 1,374 | $ 1,118 | $ 987 | $ 501 | $ 568 |
| Net income attributable to PAGP | $ 15 | $ 3 | $ 2 | $ 2 | $ 1 |
| | | | | | |
| **Per share data:** | | | | | |
| Basic and diluted net income per Class A share (1) | $ 0.10 | N/A | N/A | N/A | N/A |
| | | | | | |
| **Balance sheet data (at end of period):** | | | | | |
| Total assets | $ 21,453 | $ 19,259 | $ 15,414 | $ 13,734 | $ 12,388 |
| Long-term debt | $ 7,230 | $ 6,520 | $ 4,720 | $ 4,831 | $ 4,342 |
| Total debt | $ 8,343 | $ 7,606 | $ 5,406 | $ 6,161 | $ 5,416 |
| **Partners capital/Members equity:** | | | | | |
| Partners capital/Members equity (excluding noncontrolling interests) | $ 1,035 | $ | $ | $ | $ |
| Noncontrolling interests | 7,244 | 6,968 | 5,794 | 4,391 | 3,977 |
| Total Partners capital/Members equity | $ 8,279 | $ 6,968 | $ 5,794 | $ 4,391 | $ 3,977 |
| | | | | | |
| **Other data:** | | | | | |
| Net cash provided by operating activities | $ 1,948 | $ 1,232 | $ 2,357 | $ 248 | $ 357 |
| Net cash used in investing activities | $ (1,653) | $ (3,392) | $ (2,020) | $ (851) | $ (686) |
| Net cash provided by/(used in) financing activities | $ (274) | $ 2,159 | $ (337) | $ 613 | $ 348 |
| Capital expenditures: | | | | | |
| Acquisitions | $ 19 | $ 2,286 | $ 1,404 | $ 407 | $ 393 |
| Internal growth projects | $ 1,622 | $ 1,185 | $ 531 | $ 355 | $ 379 |
| Maintenance | $ 176 | $ 170 | $ 120 | $ 93 | $ 81 |

Table of Contents

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | **2013** | **2012** | **2011** | **2010** | **2009** |
| **Volumes** (2)(3) | | | | | |
| Transportation segment (average daily volumes in thousands of barrels per day): | | | | | |
| Tariff activities | 3,595 | 3,373 | 2,942 | 2,889 | 2,836 |
| Trucking | 117 | 106 | 105 | 97 | 85 |
| Transportation segment total | 3,712 | 3,479 | 3,047 | 2,986 | 2,921 |
| | | | | | |
| Facilities segment: | | | | | |
| Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels) | 94 | 90 | 70 | 61 | 56 |
| Rail load / unload volumes (average volumes in thousands of barrels per day) | 221 | | | | |
| Natural gas storage (average monthly capacity in billions of cubic feet) | 96 | 84 | 71 | 47 | 26 |
| NGL fractionation (average volumes in thousands of barrels per day) | 96 | 79 | 14 | 14 | 15 |
| Facilities segment total (average monthly volumes in millions of barrels) | 120 | 106 | 82 | 70 | 61 |
| | | | | | |
| Supply and Logistics segment (average daily volumes in thousands of barrels per day): | | | | | |
| Crude oil lease gathering purchases | 859 | 818 | 742 | 620 | 612 |
| NGL sales | 215 | 182 | 103 | 96 | 105 |
| Waterborne cargos | 4 | 3 | 21 | 68 | 55 |
| Supply and Logistics segment total | 1,078 | 1,003 | 866 | 784 | 772 |

(1) Attributable to post-IPO period, October 21, 2013 through December 31, 2013.

(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 capacity divided by 6 to account for the 6:1 mcf of gas to crude British thermal unit ( Btu ) equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (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, including periods prior to the closing of our IPO on October 21, 2013. Such analysis should be read in conjunction with our historical consolidated financial statements and accompanying notes. For ease of reference, we refer to the historical results of Plains All American GP LLC ( GP LLC ) prior to our IPO as being our historical financial results. Unless the context otherwise requires, references to we, us, our, and PAGP are intended to mean the business and operations of PAGP and its consolidated subsidiaries since October 21, 2013. When used in the historical context (i.e. prior to October 21, 2013), these terms are intended to mean the business and operations of GP LLC and its consolidated subsidiaries.

Our discussion and analysis includes the following:

- Executive Summary
- Company Overview
- Overview of Operating Results, Capital Investments and Significant Activities

Table of Contents

- Acquisitions and Internal Growth Projects
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements
- Results of Operations
- Outlook
- Liquidity and Capital Resources

**Executive Summary**

***Company Overview***

We are a Delaware limited partnership formed on July 17, 2013 to own an interest in the general partner and incentive distribution rights ( IDRs ) of Plains All American Pipeline, L.P ( PAA ), a publicly traded Delaware limited partnership. Although we were formed as a limited partnership, we have elected to be taxed as a corporation for United States federal income tax purposes. As of December 31, 2013, we owned a 22.1% limited partner interest in AAP, and the remaining limited partner interests in AAP continue to be held by the owners of AAP immediately prior to our IPO (the Legacy Owners ). AAP is a Delaware limited partnership that directly owns all of PAA s incentive distribution rights and indirectly owns the 2% general partner interest in PAA. AAP is the sole member of PAA GP LLC ( PAA GP ), a Delaware limited liability company that directly holds the 2% general partner interest in PAA.

Through a series of transactions prior to our IPO with our general partner and the owners of GP LLC, a Delaware limited liability company formed on May 2, 2001 that manages the business and affairs of PAA and AAP, GP LLC s general partner interest in AAP became a non-economic interest, and we became the owner of a 100% managing member interest in GP LLC. Since we are the managing member of and control GP LLC, which in turn effectively controls PAA we reflect our ownership in PAA, as well as its subsidiaries, on a consolidated basis in accordance with generally accepted accounting principles. Accordingly, our financial results are combined with those of GP LLC and PAA as well as with their subsidiaries. As such, our results of operations as discussed below do not differ materially from the results of operations of PAA.

PAA owns and operates midstream energy infrastructure and provides 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. PAA owns 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. On average, PAA handles over 3.5 million barrels per day of crude oil and NGL on its pipelines.

***Overview of Operating Results, Capital Investments and Significant Activities***

During 2013, net income was approximately $1.374 billion, as compared to net income of approximately $1.118 billion recognized during 2012. Major items impacting the favorable performance between periods include contributions from the USD Rail Terminal and BP NGL Acquisitions, which were completed in December 2012 and April 2012, respectively, incremental fee-based contributions associated with acquisition and expansion capital invested in our Transportation and Facilities segments and favorable unit margins in our Supply and Logistics segment.

The favorable unit margins in the Supply and Logistics segment were driven by our NGL marketing operations, which benefited from improved market conditions and higher demand, as well as additional sales volumes related to the BP NGL Acquisition noted above. However, such results were partially offset by the impact of less favorable crude oil market conditions, particularly narrower crude oil differentials during much of 2013.

Table of Contents

Other significant items impacting the comparison to 2012 include:

- Decreased depreciation and amortization expense, largely driven by one-time asset impairment charges of approximately $168 million recognized during the comparative 2012 period; and

- Increased income tax expense resulting from an increased proportion of earnings subject to Canadian federal and provincial taxes, primarily driven by the stronger performance from our existing operations and operations related to the BP NGL Acquisition.

**Acquisitions and Internal Growth Projects**

We completed a number of acquisitions and capital expansion projects in 2013, 2012 and 2011 that have impacted our results of operations. The following table summarizes our capital expenditures for acquisitions, internal growth projects and maintenance capital for the periods indicated (in millions):

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | **2013** | **2012** | **2011** |
| Acquisition capital (1) | $ 19 | $ 2,286 | $ 1,404 |
| Internal growth projects | 1,622 | 1,185 | 531 |
| Maintenance capital | 176 | 170 | 120 |
| | $ 1,817 | $ 3,641 | $ 2,055 |

(1) 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, PAA issued approximately 14.7 million of its common units with a value of approximately $760 million.

***Acquisitions***

Acquisitions are financed using a combination of equity and debt, including borrowings under 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 2013, 2012 and 2011 is set forth in the table below (in millions):

| **Acquisition** | **Effective Date** | **Acquisition Price** | **Operating Segment** |
|---|---|---|---|
| 2013 Total (1) | 09/01/2013 | $ 19 | Transportation |

| | | | | |
|---|---|---|---|---|
| BP NGL Acquisition (2) | 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 | |
| | | | | |
| Southern Pines | 02/09/2011 | $ | 765 | Facilities |
| Gardendale Gathering System | 11/29/2011 | | 349 | Transportation |
| Western Pipeline and Storage Assets | 12/29/2011 | | 220 | Facilities and Transportation |
| Other | Various | | 70 | Transportation, Facilities and Supply and Logistics |
| 2011 Total | | $ | 1,404 | |

(1) 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, PAA issued approximately 14.7 million of its common units with a value of approximately $760 million.

(2) Total BP NGL Acquisition purchase price was approximately $1.683 billion. A cash deposit of $50 million was paid during 2011 and is reflected in Other in the 2011 Total in the table above.

Table of Contents

***Internal Growth Projects***

Our 2013 projects included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2013, 2012 and 2011 projects (in millions):

| Projects | 2013 | 2012 | 2011 |
|---|---|---|---|
| Mississippian Lime Pipeline (1) | $ 163 | $ 54 | $ |
| Gulf Coast Pipeline (1) | 125 | 13 | |
| Rainbow II Pipeline | 124 | 79 | 44 |
| Yorktown Terminal Projects | 114 | 39 | |
| Eagle Ford Area Pipeline Projects (1) (2) | 86 | 88 | 2 |
| Rail Terminal Projects (4) | 83 | 41 | 27 |
| White Cliffs Expansion (5) | 73 | 1 | |
| Fort Saskatchewan Facility Expansions | 73 | | |
| Cactus Pipeline (1) | 64 | | |
| Eagle Ford JV Project (1) (3) | 60 | 132 | 18 |
| Spraberry Area Pipeline Projects (1) | 51 | 91 | |
| St. James Expansions (1) | 51 | 46 | 4 |
| Western Oklahoma Pipeline (1) | 50 | | |
| Natural Gas Storage (multiple projects) (1) | 45 | 61 | 89 |
| Cushing Terminal Expansions (1) | 38 | 31 | 41 |
| Gulf Coast Gas Processing Facility Enhancements | 36 | | |
| Shafter Expansion | 28 | 21 | 2 |
| Other projects | 358 | 488 | 304 |
| Total | $ | | |