PLAINS GP HOLDINGS LP
Form 10-K
February 23, 2017
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2016

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	90-1005472
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
333 Clay Street, Suite 1600, Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

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, 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 x No o

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

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

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

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

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

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

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

The aggregate market value of the 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 $2.6 billion on June 30, 2016, based on a closing price of $27.77 per Class A share as reported on the New York Stock Exchange on such date.

As of February 10, 2017, there were 103,269,257 Class A shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE
NONE

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FORWARD-LOOKING STATEMENTS

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements incorporating the words "anticipate," "believe," "estimate," "expect," "plan," "intend" a "forecast," as well as similar expressions and statements 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.;
- declines in the volume of crude oil and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our assets, whether due to declines in production from existing oil and gas reserves, reduced demand, failure to develop or slowdown in the development of additional oil and gas reserves, whether from reduced cash flow to fund drilling or the inability to access capital, or other factors;
- the effects of competition;
- market distortions caused by producer over-commitments to new or recently constructed infrastructure projects, which impacts volumes, margins, returns and overall earnings;
- 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;
- maintenance of PAA's credit rating and ability to receive open credit from suppliers and trade counterparties;
- 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 (including eco-terrorist attacks) or other event, including attacks on our electronic and computer systems;
- failure to implement or capitalize, or delays in implementing or capitalizing, on expansion projects, whether due to permitting delays, permitting withdrawals or other factors;
- tightened capital markets or other factors that increase our cost of capital or limit our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;
- 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 currency exchange rate of the Canadian dollar;
- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;
- inability to recognize current revenue attributable to deficiency payments received from customers who fail to ship or move more than minimum contracted volumes until the related credits expire or are used;
- non-utilization of our assets and facilities;
- increased costs, or lack of availability, of insurance;
- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- the effectiveness of our risk management activities;
- shortages or cost increases of supplies, materials or labor;
- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements, and related interpretations;

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- 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;
- risks related to the development and operation of our assets, including our ability to satisfy our contractual obligations to our customers;
- 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 in July 2013 that has elected to be taxed as a corporation for United States federal income tax purposes. PAGP does not directly own any operating assets; as of December 31, 2016, its principal sources of cash flow are derived from its indirect investment in Plains All American Pipeline, L.P ("PAA"), a publicly traded Delaware limited partnership. As used in this Form 10-K and unless the context indicates otherwise (taking into account the fact that PAGP has no operating activities apart from those conducted by PAA and its subsidiaries), the terms "Partnership," "we," "us," "our," "ours" and similar terms refer to PAGP and its subsidiaries.

Organizational History

We completed our initial public offering ("IPO") in October 2013, and our Class A shares are publicly traded on the New York Stock Exchange (NYSE) under the ticker symbol "PAGP". Immediately prior to completion of our IPO, certain owners of Plains AAP, L.P. ("AAP") transferred a portion of their interests in AAP to us, resulting in our ownership of a limited partnership interest in AAP. As of December 31, 2016, our sole assets consisted of (i) a 100% managing member interest in Plains All American GP LLC ("GP LLC") that has also elected to be taxed as a corporation for United States federal income tax purposes and (ii) an approximate 42% limited partner interest in AAP through our direct ownership of approximately 100.2 million Class A units of AAP ("AAP units") and indirect ownership of approximately 1.0 million AAP units through GP LLC. As of such date, the remaining limited partner interests in AAP were held by a group of owners that included many of the owners of AAP immediately prior to our IPO and various current and former members of management (collectively, the "Legacy Owners"). GP LLC is a Delaware limited liability company that also holds the non-economic general partner interest in AAP. AAP is a Delaware limited partnership that, as of December 31, 2016, directly owned an approximate 33% limited partner interest in PAA represented by 241.7 million PAA common units. AAP is the sole member of PAA GP LLC ("PAA GP"), a Delaware limited liability company that directly holds the non-economic general partner interest in PAA. Our non-economic general partner interest is held by PAA GP Holdings LLC ("PAGP GP"), a Delaware limited liability company.

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. 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.

References to the "PAGP Entities" include PAGP GP, PAGP, GP LLC, AAP and PAA GP. References to the "Plains Entities" include the PAGP Entities and PAA and its subsidiaries.

Simplification Transactions

On November 15, 2016, the Plains Entities closed a series of transactions and executed several organizational and ancillary documents (the "Simplification Transactions") intended to simplify PAA's capital structure, better align the interests of PAA's stakeholders (including us) and improve PAA's overall credit profile. The Simplification Transactions included, among other things: the permanent elimination of PAA's incentive distribution rights ("IDRs") and the economic rights associated with its 2% general partner interest in exchange for the issuance by PAA to AAP of 245.5 million PAA common units (including approximately 0.8 million PAA common units to be issued in the future) and the assumption by PAA of all of AAP's outstanding debt ($642 million); the implementation of a unified governance structure pursuant to which the board of directors of PAA's general partner was eliminated and an expanded board of directors of PAGP GP (the "PAGP GP Board") assumed oversight responsibility over both us and PAA; and provision for annual shareholder elections beginning in 2018 with certain directors with expiring terms in 2018, and the participation of PAA's common unitholders in such elections through PAA's ownership of newly issued Class C shares in us, which provide PAA, as the sole holder, the right to vote in elections of eligible PAGP GP directors together with the holders of our Class A and Class B shares. In addition, we entered into an Omnibus Agreement with AAP and PAA to promote economic alignment between our Class A shareholders and PAA's common unitholders by, among other measures, maintaining a one-to-one relationship between the number of our outstanding Class A shares and the number of PAA's common units indirectly owned by us through AAP.

See Note 1 to our Consolidated Financial Statements for further discussion of the Simplification Transactions.

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Partnership Structure and Management

Our general partner manages our operations and activities and is responsible for exercising on our behalf any rights we have as the sole and managing member of GP LLC. The PAGP GP Board has ultimate responsibility for managing the business and affairs of AAP, PAA and us. See Item 10. "Directors and Executive Officers of Our General Partner and Corporate Governance." 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 ("PMC"). Our general partner does not receive a management fee or other compensation in connection with its management of our business.

The two diagrams below show our organizational structure and ownership as of December 31, 2016 in both a summarized and more detailed format. The first diagram depicts our legal structure in summary format, while the second diagram depicts a more comprehensive view of such structure, including ownership and economic interests and shares and units outstanding:

Summarized Partnership Structure
(as of December 31, 2016)

(1) We will hold an annual meeting for the election of eligible PAGP GP directors beginning in 2018. See Item 10. "Directors and Executive Officers of our General Partner and Corporate Governance" for further information regarding governance of the Plains Entities, including changes as a result of the Simplification Transactions.

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Detailed Partnership Structure
(as of December 31, 2016)

(1) As of December 31, 2016, the PAGP GP Board consisted of 10 members. In February 2017, the limited liability agreement of PAGP GP was amended and restated to provide for two additional directors. See Item 10. “Directors and

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Executive Officers of our General Partner and Corporate Governance" for further information regarding governance of the Plains Entities.

(2) Represents the number of AAP units for which the outstanding Class B units of AAP (referred to herein as the "AAP Management Units") will be exchangeable, assuming the conversion of all such units at the rate of approximately 0.941 AAP units for each AAP Management Unit.

(3) Assumes conversion of all outstanding AAP Management Units into AAP units.

(4) Each Class C share represents a non-economic limited partner interest in us and carries with it the right to vote, pro rata with the holders of our Class A and Class B shares, for the election of eligible PAGP GP directors.

(5) Amount does not include 792,074 PAA common units that will become issuable to AAP that relate to AAP Management Units that are outstanding but not earned. See Note 16 to our Consolidated Financial Statements for additional discussion of the AAP Management Units.

(6) 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 PMC.

(7) PAA holds indirect equity interests in unconsolidated entities including BridgeTex Pipeline Company, LLC ("BridgeTex"), Butte Pipe Line Company ("Butte"), Caddo Pipeline LLC ("Caddo"), Cheyenne Pipeline LLC ("Cheyenne"), Diamond Pipeline LLC ("Diamond"), Eagle Ford Pipeline LLC ("Eagle Ford Pipeline"), Eagle Ford Terminals Corpus Christi LLC ("Eagle Ford Terminals"), Frontier Aspen LLC ("Frontier"), Saddlehorn Pipeline Company, LLC ("Saddlehorn"), Settoon Towing, LLC ("Settoon Towing"), STACK Pipeline LLC ("STACK") and White Cliffs Pipeline LLC ("White Cliffs").

Our Business

As of December 31, 2016, our only cash-generating assets consisted of approximately 101.2 million AAP units, which represented an approximate 42% limited partner and economic interest in AAP. Of these AAP units, we directly own approximately 100.2 million, and we indirectly own the remaining 1.0 million AAP units through our 100% ownership in GP LLC. 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 on the AAP units. AAP currently receives all of its cash flows from distributions on common units it owns in PAA. As of December 31, 2016, AAP owned approximately 241.7 million common units in PAA.

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, making loans, purchasing equity interests or providing other forms of financial support to PAA.

Subsequent to the Simplification Transactions, we have and will maintain a one-to-one relationship between our Class A shares and the underlying PAA common units in which we have an indirect economic interest through our ownership interest in AAP (referred to as "Economic Parity"), such that the number of our outstanding Class A shares equals the number of AAP units we directly and indirectly own, which in turn equals the number of PAA common units held by AAP attributable to our direct and indirect ownership in AAP.

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 supply, logistics and distribution expertise. 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:

- optimizing its existing assets and realizing cost efficiencies through operational improvements;
- using its transportation, terminalling, storage, processing and fractionation assets in conjunction with its supply and logistics activities to capture inefficiencies, address physical market imbalances, mitigate inherent risks and increase margin;

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- developing and implementing growth projects that (i) address evolving crude oil and NGL needs in the midstream transportation and infrastructure sector and (ii) are well positioned to benefit from long-term industry trends and opportunities; and
- selectively pursuing strategic and accretive acquisitions that complement its existing asset base and distribution capabilities.

PAA's Competitive Strengths

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

- Many of PAA's 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 crude oil producing regions and other transportation corridors and are connected, directly or indirectly, with PAA's Facilities segment assets. The majority of PAA's Facilities segment assets are located at major trading locations and premium markets that serve as gateways to major North American refinery and distribution markets where PAA has strong business relationships. In addition, PAA's assets include pipeline, rail, barge, truck and storage 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 and NGL market knowledge. We believe PAA's business relationships with participants in various phases of the crude oil and NGL distribution chain, from producers to refiners, as well as PAA's own industry expertise (including PAA's knowledge of North American crude oil and NGL flows), provide PAA with an extensive understanding of the North American physical crude oil and NGL 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 low risk opportunity to generate a base level of margin, the amount of which may vary depending on market conditions (such as commodity price levels, differentials and certain competitive factors). In certain market scenarios, PAA may be able to realize incremental margins that meaningfully exceed such base levels.
- PAA has the evaluation, integration and engineering skill sets and the financial flexibility to continue to pursue acquisition and expansion opportunities. Since 1998, PAA has completed and integrated over 90 acquisitions with an aggregate purchase price of approximately $13.2 billion including the February 2017 acquisition of the Alpha Crude Connector gathering system. Since 1998, PAA has also implemented expansion capital projects totaling approximately $11.4 billion. In addition, considering PAA's investment grade credit rating, liquidity and capital structure, we believe PAA has the financial resources and strength necessary to finance future strategic expansion and acquisition opportunities. As of December 31, 2016, PAA had approximately $2.4 billion of liquidity available, including cash and cash equivalents and availability 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 31 years of industry experience, and an average of 19 years with PAA or its predecessors and affiliates. In addition, through their ownership of PAA common units, grants of phantom units and interests in us, AAP units and AAP Management Units, PAA's management team has a vested interest in PAA's continued success.

Our Financial Strategy

Our financial strategy is designed to be complementary to PAA's financial and business strategies. Our only cash-generating assets consist of our direct and indirect limited partner interests in AAP, which currently receives all of its cash flows from distributions on the PAA common units it owns.

In connection with the Simplification Transactions, we entered into an Omnibus Agreement which provides for (i) our ability to issue additional Class A shares and use the net proceeds therefrom to purchase a like number of AAP units from AAP, and the corresponding ability of AAP to use the net proceeds therefrom to purchase a like number of PAA common units from PAA and (ii) our ability to lend proceeds of any future indebtedness we incur to AAP, and AAP's corresponding ability to lend such proceeds to PAA, in each case on substantially the same terms as we incur.

Accordingly, we intend to access the equity capital markets from time to time to enhance the financial position of PAA and its ability to compete for incremental capital opportunities (including organic investments and third-party acquisitions) to drive future growth. We currently do not intend to incur any indebtedness in the near term. 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 50% or less;
- 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 and further adjusted for selected items that impact comparability. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Non-GAAP Financial Measures" for a discussion of our selected items that impact comparability and our non-GAAP measures.);
- an average total debt-to-total capitalization ratio of approximately 60% or less; 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 Intercontinental Exchange ("ICE") margin requirements. In certain market conditions, these routine short-term debt levels may increase significantly above baseline levels. For example, PAA's short-term debt levels at December 31, 2016 included borrowings for $410 million of margin requirements, which is significantly elevated from historical levels primarily due to the increase in crude oil prices at the end of the year. For the years ended December 31, 2015 and 2014, we had positive cash flow associated with such margin balance activities at the end of the year of $157 million and $133 million, respectively.

Typically, for PAA to maintain its targeted credit profile and achieve growth through acquisitions and expansion capital, PAA funds 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, capital expenditures and acquisitions may be financed initially using debt or there may be delays in realizing anticipated synergies from acquisitions or contributions from expansion capital projects to adjusted EBITDA. As a result of the challenging environment and the impact of the gap in the timing between funding PAA's capital program and the time the assets are placed in service and begin to generate cash flow, PAA expects its long-term debt-to-adjusted EBITDA to be above its target range for the near-term. PAA expects this leverage ratio will improve and return to targeted levels as PAA executes its 2017 funding plan, completes the 2017 asset sales, and as the industry recovers and PAA realizes EBITDA growth from capital investments.

To improve PAA's ability to manage through the industry downturn and to position for a recovery, PAA completed a number of initiatives during 2016 to maintain a solid capital structure, significant liquidity and overall financial flexibility. Such initiatives included (i) executing the Simplification Transactions in November 2016, which lowered PAA's incremental cost of equity through the elimination of its IDRs, and in connection therewith resetting its distribution level, which resulted in an annual reduction in cash distributions of approximately $320 million, (ii) securing approximately $1.6 billion of equity capital through the sale of new Series A preferred units in January 2016, (iii) selectively utilizing PAA's continuous offering program to raise approximately $796 million of net proceeds, (iv) selling non-core assets and entering into strategic joint ventures, which raised approximately $550 million of net cash proceeds while reducing PAA's capital commitments and (v) entering into a definitive agreement to sell additional assets for approximately $290 million that is expected to close in the first half of 2017, subject to regulatory approvals. See Note 6 and Note 11 to our Consolidated Financial Statements for additional discussion of these transactions.

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PAA intends to end 2017 with a long-term debt balance at or below levels at December 31, 2016. To that end, PAA expects that its 2017 acquisition and expansion capital will be funded with proceeds from asset sales, equity issuances and retained cash flow.

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 and NGL logistics assets as well as other energy assets that have characteristics and provide opportunities similar to its existing 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.

Acquisition [(1)]	Date	Description	Approximate Purchase Price [(2)] (in millions)	
Alpha Crude Connector Gathering System	Feb-2017	Recently constructed gathering system located in the Northern Delaware Basin	$ 1,215	(3)
Spectra Energy Partners Western Canada NGL Assets	Aug-2016	Integrated system of NGL assets located in Western Canada	$ 204	(4)
50% Interest in BridgeTex Pipeline Company, LLC ("BridgeTex")	Nov-2014	BridgeTex owns a crude oil pipeline that extends from Colorado City, Texas to East Houston	$ 1,088	(5)
US Development Group Crude Oil Rail Terminals	Dec-2012	Four operating crude oil rail terminals and one terminal under development	$ 503	
BP Canada Energy Company	Apr-2012	NGL assets located in Canada and the upper-Midwest United States	$ 1,683	(6)

(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 subject to working capital and other adjustments. See Note 6 to our Consolidated Financial Statements for additional information regarding this acquisition.

(4) Approximate purchase price of $180 million, net of cash, inventory and other working capital acquired.

(5) Approximate purchase price of $1.075 billion, net of working capital acquired. PAA accounts for its 50% interest in BridgeTex under the equity method of accounting.

(6) 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.

PAA's Divestitures

During 2016, PAA initiated a program to evaluate potential sales of non-core assets and/or sales of partial interests in assets to strategic joint venture partners to optimize its asset portfolio and strengthen its balance sheet and leverage metrics. This program currently totals approximately $1.2 billion of asset sales, of which approximately $550 million closed in 2016, with the remaining $670 million either already closed or expected to close during the first half of 2017. See Note 6 to our Consolidated Financial Statements for additional discussion of dispositions and divestitures.

Ongoing Acquisition, Divestiture and Investment Activities

Consistent with its business strategy, PAA is continuously engaged in the evaluation of potential acquisitions, joint ventures and capital projects. In addition, PAA continues to evaluate its asset portfolio to determine whether additional sales of non-core assets would further optimize its portfolio and strengthen its balance sheet. As a part of these efforts, PAA often

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engages in discussions with potential third parties regarding the possible purchase of or investment in assets and operations that are strategic and complementary to PAA's existing operations, or the potential sale of assets that it believes might have more value to a third-party buyer. In addition, in the past PAA has evaluated and pursued, and intends in the future to evaluate and pursue, the acquisition of or investment in other energy-related assets that have characteristics and provide opportunities similar to PAA's existing business lines and enable PAA to leverage its assets, knowledge and skill sets. Such efforts may involve participation by PAA in processes that have been made public and involve a number of potential buyers or investors, commonly referred to as "auction" processes, as well as situations in which PAA believes it is the only party or one of a limited number of parties who are in negotiations with the potential seller or other party. With respect to a potential divestiture, PAA may also conduct an auction process or may negotiate a transaction with one or a limited number of potential buyers. These acquisition and investment efforts often involve assets which, if acquired, constructed or sold, as applicable, 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 agreement. However, in certain cases in order to protect its business interests or for other reasons, PAA may defer public announcement of a transaction until closing or a later date. Past experience has demonstrated that discussions and negotiations regarding a potential transaction can advance or terminate in a short period of time. Moreover, the closing of any transaction for which PAA has entered into a definitive agreement may 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, divestiture or investment efforts will be successful. Although PAA expects the acquisitions and investments 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 "—Acquisitions involve risks that may adversely affect PAA's business."

PAA's Expansion Capital 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's 2017 expansion capital plan is representative of the diversity and balance of its overall project portfolio. The following expansion capital projects are included in PAA's 2017 capital plan as of February 2017:

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Basin/Region	Project	2017 Plan Amount [1] ($ in millions)	Description	Projected In-Service Date
Permian	Permian Basin Area Gathering System Projects	$ 120	Multiple projects to increase and expand our pipeline infrastructure in the Delaware Basin, including planned interconnects associated with the recently acquired Alpha Crude Connector gathering system	Q1 2017 - 2018
Central / Mid-Continent	Diamond Pipeline	300	50% interest in approximately 440 miles of new crude oil pipeline; 200,000 Bbls/d capacity from Cushing, OK to Valero's refinery in Memphis, TN	Q4 2017
	Cushing Terminal Expansions	30	Addition of approximately 2.1 million barrels of storage capacity and additional	Q2 2017 - Q4 2017
Canada	Fort Saskatchewan Facility Projects	90	Multi-phase project, remaining Phase I project includes conversion of service of approximately 3 million barrels of existing caverns Remaining Phase II projects include (i) adding a merox sweetening unit that will increase our ability to handle a variety of feed streams providing more flexibility and flow assurance, (ii) development of two new ethane caverns with 1.6 million barrels of capacity and a utility cavern and (iii) the addition of 2.7 million barrels of brine capacity Phase III includes a six-spot rail rack expansion for condensate service and adding butane service to four existing propane spots	Q1 2017 - 2018
Other	Other Projects	260		Q1 2017 - 2018+
Total Projected Expansion Capital Expenditures		$ 800		

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

Global Petroleum Market Overview

The health of the global petroleum market is dependent on the relative supply and demand of hydrocarbons, including crude oil and NGL. These supply and demand economics are greatly influenced by the broader global economic climate, exposing the petroleum market to the challenges and volatility associated with global economic development. For the period from 2004 through 2013, global liquids production increased 7.6 million barrels per day while global liquids consumption increased 8.4 million barrels per day. For the period from 2013 through 2015, global production growth outpaced global consumption growth by 2.5 million barrels per day resulting in a cumulative imbalance of 2.3 million barrels per day. In 2016, the market remained oversupplied, but global demand growth began to outpace global supply growth as non-OPEC production declined 0.6 million barrels per day. The table below depicts historical OPEC and non-OPEC liquids production and global liquids consumption and is derived from the EIA Short-Term Energy Outlook, January 2017 (see EIA website at www.eia.doe.gov):

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	Annual Liquids Production (1)					Δ from	Δ from	Δ from
	2004	2013	2014	2015	2016	2004-2013	2013-2015	2015-2016
	(in millions of barrels per day) (2)							
Production (Supply)								
OPEC	35.0	37.6	37.5	38.7	39.6	2.6	1.1	0.9
Non-OPEC	48.4	53.4	55.9	57.5	56.8	5.0	4.1	(0.6)
Total	83.4	91.0	93.4	96.1	96.4	7.6	5.2	0.3
Total Consumption (Demand)	83.0	91.4	92.6	94.1	95.6	8.4	2.7	1.4
Global Supply / Demand Balance	0.4	(0.5)	0.8	2.0	0.9	(0.9)	2.5	(1.1)

(1) Amounts are derived from the EIA's Short-Term Energy Outlook.
(2) Amounts may not recalculate due to rounding.

This surge in liquids production without a commensurate increase in demand has led to a near-to-medium-term supply imbalance and increase in inventory, which has resulted in a reduction to benchmark petroleum prices. Producers, in turn, scaled back capital programs, which ultimately reduced supply. These outcomes are expected to lead to underinvestment in long lead time projects and additionally stimulate petroleum demand growth, which ultimately should lead to an environment where prices will recover to a level to support future production growth in the U.S.

In November 2016, OPEC indicated a desire to return to its historical strategy of managing crude oil production levels. Joined by certain non-OPEC countries such as Russia and Mexico, OPEC and non-OPEC participants have targeted to cut output by approximately 1.8 million barrels per day in the first of half of 2017. This decision drove a significant increase in crude oil prices during the fourth quarter of 2016. To the extent the production cut is executed and demand growth stays on trend, accumulated inventories should begin to decline, prices should remain firm and potentially rise, ultimately leading to increased activity levels.

Crude Oil Market Overview

The definition of a commodity is a "mass-produced unspecialized product" and implies the attribute of fungibility. Crude oil is typically referred to as a commodity; however, it is neither unspecialized nor fungible. The crude slate available to U.S. and world-wide refineries consists of a substantial number of different grades and varieties of crude oil. Each crude oil grade has distinguishing physical properties. For example, specific gravity (generally referred to as light or heavy), sulfur content (generally referred to as sweet or sour) and metals content, along with other characteristics, collectively result in varying economic attributes. In many cases, these factors result in the need for such grades to be batched or segregated in the transportation and storage processes, blended to precise specifications or adjusted in value.

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

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

From 2011 through 2014, the combination of (i) a significant increase in North American production volumes, (ii) a change in crude oil qualities and related differentials and (iii) high utilization of existing pipeline and terminal infrastructure stimulated multiple industry initiatives to build new pipeline and terminal infrastructure, convert certain pipeline assets to

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alternative service or reverse flows and expand the use of trucks, rail and barges for the movement of crude oil and condensate. Increased production came from mature producing areas such as the Rockies, the Permian Basin in West Texas and the Mid-Continent region, as well as from less mature, but rapidly growing areas such as the Eagle Ford Shale in South Texas and the Williston Basin in North Dakota. As a result, North American crude oil production increased 3.7 million barrels per day, or 33% between 2011 and 2014, with the increases coming primarily from Canada, the Eagle Ford Shale, the Permian Basin and the Williston Basin. Production increases in all of these regions strained existing transportation, terminalling and downstream infrastructure. This opportunity for new crude oil infrastructure attracted significant investment in midstream oil assets, resulting in excess midstream capacity in the Permian, Eagle Ford, Williston, Mid-continent and DJ basins. The combination of the slowdown in U.S. crude oil production growth and significant commitments for new infrastructure created an environment in which margins have compressed and differentials are less than transportation cost in some cases. As production growth resumes and pipeline utilizations increase, differentials should approach transportation cost parity. The improvement is expected to occur on a regional basis subject to reductions in excess capacity.

In addition, significant shifts in the type and location of crude oil being produced in North America, relative to the types and location of crude oil being produced five years ago, have led to changes in the utilization of downstream infrastructure. From 2009 through 2015, refiners increased throughputs to take advantage of discounted domestic production, which led to lower use of imported crude oil by U.S. refineries. This decline in imports was a meaningful change in a multi-year trend where foreign imports of crude oil tripled over an approximately 23-year period from 1985 to 2007. However, in 2016, this more recent trend reversed as a result of lower 48 onshore production declines. In 2016, U.S. refinery inputs reached historically high levels fueled by price driven demand growth and exports, and U.S. petroleum consumption increased to 19.6 million barrels per day. The table below shows the overall domestic petroleum consumption projected through 2018 and is derived from the EIA Short-Term Energy Outlook, January 2017 (see EIA website at www.eia.doe.gov). This forecast shows increasing domestic production, decreasing foreign imports and steady levels of product exports.

	Actual [1]	Projected [1]	
	2016	2017	2018
	(in millions of barrels per day)		
Supply			
Domestic Crude Oil Production	8.9	9.0	9.3
Net Imports - Crude Oil	7.3	6.9	6.7
Other - (Supply Adjustment/Stock Change)	—	0.3	0.3
Crude Oil Input to Domestic Refineries	16.2	16.2	16.3
Net Product Imports / (Exports)	(2.6)	(2.5)	(2.6)
Supply from Renewable Sources	1.1	1.1	1.2
Other - (NGL Production, Refinery Processing Gain)	4.8	5.0	5.4
Total Domestic Petroleum Consumption	19.6	19.8	20.2

[1] Amounts may not recalculate due to rounding.

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. Liquefied petroleum gas ("LPG") primarily includes propane and butane, which liquefy at moderate pressures thus making it easier to transport and store such products as compared to ethane. NGL refers to all NGL products including LPG when used in this Form

10-K.

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.

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- 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 82%) of the United States NGL supply comes from gas processing plants, which separate a mixture of NGL from the dry gas (primarily methane). This NGL mix (also referred to as “Y Grade”) is then either fractionated at the processing site into the five individual NGL components (known as purity products), which may be transported, stored and sold to end use markets, or transported as a Y-Grade to a regional fractionation facility.

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

NGL products from refineries represent approximately 14% of the United States supply and are by-products of the refinery conversion processes. Consequently, they have generally already been separated into individual components and do not require further fractionation. NGL products from refineries are principally propane, with lesser amounts of butane, refinery naphthas (products similar to natural gasoline) and ethane. Due to refinery maintenance schedules and seasonal demand considerations, refinery production of propane and butane varies on a seasonal basis.

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

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; however, product is also stored in above ground tanks. Natural gasoline can be stored at relatively low pressures in tankage similar to that used to store motor gasoline. Propane and butane are stored at much higher pressures in steel spheres, cylinders, bullets, salt caverns or other configurations. Ethane is stored at very high pressures, typically in salt caverns. Storage is especially important for NGL as supply and demand can vary materially on a seasonal basis.

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

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

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the increased supply of NGL will be absorbed by the domestic petrochemical sector as low-cost feed stocks, as the North American petrochemical industry has enjoyed a supply cost advantage on a world scale.

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

- the absolute prices of NGL products and their prices relative to natural gas and crude oil;
- drilling activity and wet natural gas production in developing liquids-rich production areas;
- available processing, fractionation, storage and transportation capacity;
- petro-chemical demand driven by the build-out or new builds of Ethylene Cracker capacity (ethane demand) and Propane Dehydrogenation facilities (propane demand);
- increased export capacity for both ethane and propane;
- diluent requirements for heavy Canadian oil;
- regulatory changes in gasoline specifications affecting demand for butane;
- seasonal demand from refiners;
- seasonal weather related demand; 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) a shift from Gulf of Mexico production to Northeast production causing less concern over disruptions from tropical weather and (iii) lower basis differentials in certain regions due to expansion and improved connectivity of natural gas transportation infrastructure.

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) increased exports of natural gas to Mexico, (iii) construction of new gas-fired power plants, (iv) sustained fuel switching from coal to natural gas among existing power plants and (v) 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.

Description of Segments and Associated Assets

Under GAAP, we consolidate GP LLC, 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.

We have an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada.

The map and descriptions below highlights our more significant assets (including certain assets under construction or development) as of December 31, 2016:

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

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Transportation Segment

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

As of December 31, 2016, 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:

- 19,200 miles of active crude oil and NGL pipelines and gathering systems;
- 31 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;
- 810 trailers (primarily in Canada); and
- 120 transport and storage barges and 60 transport tugs through our interest in Settoon Towing.

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, 2016, grouped by geographic location:

Region / Pipeline and Gathering Systems [1]	System Miles	2016 Average Net Barrels per Day [2] (in thousands)
United States Crude Oil Pipelines		
Permian Basin		
Basin / Mesa / Sunrise	770	992
BridgeTex [3] [4]	408	108
Cactus	297	125
Permian Basin Area Systems	2,796	921
Permian Basin Subtotal	4,271	2,146
South Texas/Eagle Ford		
Eagle Ford Area Systems [4]	660	284
South Texas/Eagle Ford Subtotal	660	284
Western		
All American [5]	138	—
Line 63 / Line 2000	382	104
Other	121	84
Western Subtotal	641	188
Rocky Mountain		
Bakken Area Systems [4]	991	146
Cheyenne [4]	87	10
Saddlehorn [3] [4]	538	6
Salt Lake City Area Systems [4]	977	178
White Cliffs [3] [4]	1,054	42
Other	1,225	67
Rocky Mountain Subtotal	4,872	449

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Region / Pipeline and Gathering Systems [1]	System Miles	2016 Average Net Barrels per Day [2] (in thousands)
Gulf Coast		
Capline [3]	631	194
Pascagoula	41	143
Other	506	160
Gulf Coast Subtotal	1,178	497
Central		
Mid-Continent Area Systems [4]	2,696	325
Other	217	69
Central Subtotal	2,913	394
United States Crude Oil Pipelines Total	14,535	3,958
Canada Crude Oil Pipelines		
Manito	445	42
Rainbow	830	91
Rangeland	1,076	52
South Saskatchewan	342	60
Other	201	136
Canada Crude Oil Pipelines Total	2,894	381
Crude Oil Pipelines Total	17,429	4,339
Canada NGL Pipelines		
Co-Ed	595	61
PPTC	593	5
Other	548	118
Canada NGL Pipelines Total	1,736	184
Grand Total	19,165	4,523

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

(2) Represents average daily volumes for the entire year attributable to our interest. Average daily volumes are calculated as the total volumes (attributable to our interest) for the year divided by the number of days in the year. Volumes reflect tariff movements and thus might be included multiple times as volumes move through our integrated system.

(3) Pipelines operated by a third party.

(4) Includes total mileage and volumes (attributable to our interest) from pipelines owned by unconsolidated entities.

(5) Except for the segment of the All American Pipeline between Pentland and Emidio, the pipeline has been shut down since May 19, 2015, following the Line 901 incident.

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United States Pipelines

A significant portion of our U.S. pipeline assets are interconnected and are operated as a contiguous system. The following descriptions are based on geographic location.

Permian Basin

Basin Pipeline. We own an 87% undivided joint interest in and are the operator of Basin Pipeline. Basin Pipeline is a 607-mile mainline, and is the 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. Basin Pipeline 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 segment of the pipeline from Wink to Midland, Texas includes both a 24-inch pipeline and a 20-inch pipeline; together these lines have a capacity of approximately 600,000 barrels per day. The segment of the pipeline from Midland, Texas to Cushing, Oklahoma is a 22-inch to 24-inch telescoping pipeline with capacity ranging from 400,000 barrels per day to 460,000 barrels per day. The pipeline also includes approximately 6 million barrels of storage tankage, as well as a receipt facility in southern Oklahoma to aggregate South Central Oklahoma Oil Province (SCOOP) production.

Mesa Pipeline. We own a 63% undivided interest in and are the operator of Mesa Pipeline, which transports crude oil from Midland to a refinery at Big Spring, Texas, and to connecting carriers at Colorado City. Mesa Pipeline is an 80-mile mainline with capacity of up to 400,000 barrels per day (approximately 252,000 barrels per day attributable to our interest).

Sunrise Pipeline. We own and operate the Sunrise Pipeline, an 84-mile pipeline with a capacity of approximately 250,000 barrels per day that extends from Midland to connecting carriers at Colorado City.

BridgeTex Pipeline. We own a 50% interest in BridgeTex, a joint venture with a subsidiary of Magellan Midstream Partners, L.P. ("Magellan"). BridgeTex owns a 20-inch crude oil pipeline that extends from Colorado City to East Houston, Texas. At Colorado City, the BridgeTex pipeline is connected to our Basin and Sunrise pipelines. The BridgeTex pipeline has a current capacity of 300,000 barrels per day, and will be expanded to 400,000 barrels per day when pumping equipment enhancements are completed in the second quarter of 2017. BridgeTex holds a long-term capacity lease agreement with Magellan whereby its shippers have access to capacity on Magellan's pipeline from Houston to Texas City. Magellan serves as the operator of the BridgeTex pipeline.

Cactus Pipeline. We own and operate the Cactus Pipeline, an approximate 300-mile crude oil pipeline extending from McCamey to Gardendale, Texas, where it connects to the Eagle Ford joint venture pipeline. The Cactus Pipeline has a current takeaway capacity of approximately 300,000 barrels per day from the Permian Basin, and will be expanded to approximately 390,000 barrels per day when manifold and metering enhancements are completed in 2017.

Permian Basin Area Pipelines. We operate wholly owned pipelines comprised of approximately 2,800 miles of pipe that aggregate receipts from wellhead gathering lines and bulk truck injection locations into trunk lines for transportation and delivery into the Basin Pipeline at Jal, Wink and Midland as well as to our terminal facilities in Midland. During 2016, we completed construction of several projects, including 63 miles of 20-inch crude oil pipeline from the Highway 285 Station in Reeves County to Wink, Texas in Winkler County, which increased capacity on that segment of our Pinon pipeline by approximately 200,000 barrels per day.

South Texas/Eagle Ford Area

Eagle Ford Area Pipelines. 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 Eagle Ford Pipeline, which owns a crude oil and condensate pipeline with approximately 660,000 barrels per day of capacity that extends from Gardendale to Corpus Christi, Texas. We serve as operator of the Eagle Ford joint venture pipeline, and our joint venture partner is a subsidiary of Enterprise Products Partners, L.P. (“Enterprise”).

Combined, these Eagle Ford Area Pipelines consist of 660 miles of pipe that service production in the Eagle Ford shale play of South Texas and include approximately 5 million barrels of operational storage capacity across the systems. The Eagle Ford Area Pipelines can source Eagle Ford production as well as Permian Basin production via a connection with the Cactus Pipeline at Gardendale. These pipelines serve the Three Rivers and Corpus Christi, Texas refineries and other markets via marine terminal facilities at Corpus Christi, as well as the Houston market via a connection with Enterprise's pipeline at Lyssy in Wilson County, Texas.

Western

All American Pipeline. We own the All American Pipeline, which receives crude oil from offshore oil producers at Las Flores, California and at Gaviota, California. The pipeline 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.

In May 2015, we experienced a crude oil release from our Las Flores to Gaviota Pipeline (Line 901) in Santa Barbara County, California. The segment of the pipeline upstream of our Pentland station has been shut down since this incident. We are currently conducting a feasibility study to evaluate a replacement of the pipeline, subject to receipt of shipper commitments and regulatory approvals. See Note 17 to our Consolidated Financial Statements for additional information regarding this incident.

Line 63. We own and operate the Line 63 pipeline that transports crude oil from the San Joaquin Valley to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield, California. The pipeline is also connected to our crude oil rail terminal at Bakersfield. The Line 63 pipeline consists of an approximate 105-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 60,000 barrels per day. The Line 63 pipeline also includes approximately 30 miles of distribution pipelines in the Los Angeles Basin with a throughput capacity of approximately 20,000 barrels per day, and approximately 115 miles of gathering pipelines in the San Joaquin Valley with an average throughput capacity of approximately 35,000 barrels per day. We also have approximately 1 million barrels of storage capacity on this pipeline. In 2016, we completed the reactivation of an approximate 70-mile segment of Line 63 that had been temporarily taken out of service to allow for certain repairs and realignments to be performed.

Line 2000. We own and operate the Line 2000 crude oil pipeline that originates at our Emidio Pump Station and transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin. Line 2000 is an approximately 130-mile, 20-inch trunk pipeline with a throughput capacity of approximately 130,000 barrels per day.

Rocky Mountain

Bakken Area Pipelines. We own and operate several gathering systems and pipelines that service crude oil production in Eastern Montana and Western North Dakota. We also own a 22% interest in Butte, which owns a 16-inch crude oil pipeline system extending from Baker, Montana to Guernsey, Wyoming.

Cheyenne Pipeline. We own a 50% interest in Cheyenne, which owns an 87-mile, 16-inch crude oil pipeline that runs from Fort Laramie to Cheyenne, Wyoming and has a capacity of 80,000 barrels per day. Cheyenne is a joint venture with a subsidiary of Holly Energy Partners, L.P., which purchased a 50% interest in Cheyenne from us in June 2016. We serve as operator of the Cheyenne pipeline, which can be expanded through the addition of pumping capacity.

Saddlehorn Pipeline. We own a 40% interest in Saddlehorn, which owns a 62.5% undivided joint interest in a 20-inch pipeline that extends from the Niobrara and DJ Basin to Cushing, Oklahoma. Saddlehorn owns 190,000 barrels per day of the capacity in the pipeline and has approximately one million barrels of storage capacity at Platteville, Colorado. The Platteville-to-Cushing segment of the pipeline was placed in service in the third quarter of 2016, and linefill is expected to begin in the latter part of the first quarter of 2017 for the Carr-to-Platteville segment. Saddlehorn has the option to expand the capacity of the pipeline at its sole discretion and cost and would own all of the incremental capacity from any expansion. Magellan serves as operator of the Saddlehorn pipeline.

Salt Lake City Area Pipelines. We operate the Salt Lake City and Wahsatch pipelines, in which we own interests ranging between 75% and 100%, and we also own a 50% interest in Frontier, which owns the Frontier pipeline. These area pipelines 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 pipelines include approximately one million barrels of storage capacity and have a maximum throughput capacity of (i) approximately 20,000 barrels per day from Wamsutter, Wyoming to Ft. Laramie, (ii) approximately 40,000 barrels per day from Wamsutter to Wahsatch, Utah, (iii) approximately 100,000 barrels per day from Wahsatch to Salt Lake City and (iv) approximately 65,000 barrels per day from Casper to Ranch Station, Utah.

White Cliffs Pipeline. We own an approximate 36% interest in White Cliffs, which owns a pipeline system consisting of two 527-mile, 12-inch, crude oil pipelines with a combined capacity of approximately 215,000 barrels per day that move crude out of the DJ Basin to the Cushing market. Rose Rock Midstream, L.P. serves as the operator of the pipeline, which originates in Platteville, Colorado and terminates in Cushing.

Gulf Coast

Capline Pipeline. Capline Pipeline, in which we own an aggregate undivided joint interest of approximately 54%, is a 631-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. Marathon Pipeline LLC serves as the operator. Capline Pipeline has direct connection to crude oil production in the Gulf of Mexico. In addition, it is connected to an active dock capable of handling approximately 600,000-barrel tankers and is also connected to the Louisiana Offshore Oil Port and our St. James terminal. 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. The Capline owners are assessing the commercial potential to reverse the pipeline direction within the next several years, potentially enabling it to transport Canadian crude oil to the Gulf Coast.

Pascagoula Pipeline. We own and operate the Pascagoula Pipeline, a 41-mile crude oil pipeline that originates at our Ten Mile facility in Alabama and extends to a refinery on the Gulf Coast. Additionally, we have approximately 2 million barrels of storage capacity at our Ten Mile facility that supports the operational needs of the Pascagoula pipeline.

Other. During the first quarter of 2016, we sold certain of our non-core Gulf Coast pipeline assets. See Note 6 to our Consolidated Financial Statements for discussion of our divestiture activities.

Central

Mid-Continent Area Pipelines. We own and operate pipelines that source crude oil from Western and Central Oklahoma, Southwest Kansas and the Eastern Texas Panhandle. These pipelines consist of approximately 2,700 miles of pipe with transportation and delivery into and out of our terminal facilities at Cushing, Oklahoma.

We also own a 50% interest in STACK, which owns a 55-mile pipeline that transports crude oil from the Sooner Trend, Anadarko Basin, Canadian and Kingfisher Counties (STACK) play in northwestern Oklahoma to the Cushing market. STACK is a joint venture with Phillips 66 Partners, L.P., which purchased a 50% interest in STACK from us in August 2016. We serve as operator of the STACK pipeline, which has a current capacity of approximately 100,000 barrels per day and includes a terminal located at Cashion, Oklahoma with approximately 200,000 barrels of crude oil storage.

Caddo Pipeline. We own a 50% interest in Caddo, a joint venture with Delek Logistics Partners, LP (“Delek”). Caddo recently constructed and commissioned an approximate 80-mile, 12-inch crude oil pipeline with the capacity to move up to 80,000 barrels per day from our terminal in Longview, Texas to supply a refinery in the Shreveport, Louisiana area, as well as to an El Dorado, Arkansas refinery through a connection to Delek’s pipeline. We serve as operator of the Caddo pipeline, which was placed in service in December 2016.

Diamond Pipeline. We own a 50% interest in Diamond, a joint venture with Valero Energy Corporation (“Valero”). Diamond is currently constructing a 20-inch, approximately 440-mile pipeline that will provide 200,000 barrels per day of capacity from our Cushing terminal to Valero’s refinery in Memphis, Tennessee. The Diamond pipeline is underpinned by a long-term shipper agreement with Valero and a related contract for storage and terminalling services at our Cushing terminal. Construction of the Diamond pipeline is expected to be completed by late 2017. We will serve as operator of the pipeline.

Red River Pipeline (Cushing to Longview). The Red River Pipeline is a 140-mile, 16-inch crude oil pipeline with takeaway capacity of 150,000 barrels per day that extends from Cushing, Oklahoma to Longview, Texas, where it connects with various pipelines, including the Caddo pipeline. The Red River Pipeline is supported by long-term shipper commitments and was placed in service in December 2016. We serve as operator of the pipeline. In January 2017, we sold an undivided 40% interest in a segment of the Red River Pipeline to a subsidiary of Valero Energy Partners LP. The undivided interest conveyed represents 60,000 barrels per day on the segment of the pipeline extending from Cushing to Hewitt, Oklahoma near Valero's refinery in Ardmore, Oklahoma (the "Hewitt Segment"). We retained an undivided 60% interest in the Hewitt Segment and a 100% interest in the remaining portion of the pipeline that extends from Ardmore to Longview, Texas.

Canada Crude Oil Pipelines

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Crude Oil Pipelines

Manito Pipeline. We own a 100% interest in the Manito heavy oil system. This 445-mile system is comprised of the Manito Pipeline and the Bodo/Cactus Lake pipeline. Each system consists of a blended crude oil line and a parallel diluent line that delivers condensate to upstream blending locations. The Manito Pipeline includes 334 miles of 6-inch to 12-inch blend pipeline. The mainline segment originates at Dulwich and terminates at Kerrobert, Saskatchewan. The Bodo/Cactus Lake pipeline is a 111-mile long, 3-inch to 10-inch blend pipeline that originates in Bodo, Alberta and also terminates at our Kerrobert storage facility. The Kerrobert storage and terminalling facility is connected to the Enbridge pipeline system and can both receive and deliver heavy crude oil from and to the Enbridge pipeline system.

Rainbow Pipeline. We own a 100% interest in the Rainbow Pipeline. The Rainbow Pipeline is comprised of (i) an approximate 470-mile, 20-inch to 24-inch mainline crude oil pipeline, with capacity of approximately 185,000 barrels per day of batched light sweet and heavy sour oil capacity, that extends from the Norman Wells Pipeline connection in Zama, Alberta to Edmonton, Alberta and has 173 miles of associated gathering pipelines and (ii) a 187-mile, 10-inch to 12-inch pipeline to transport diluent north from Edmonton to our Nipisi truck terminal in Northern Alberta.

Rangeland Pipeline. We own a 100% interest in the Rangeland Pipeline. Rangeland Pipeline consists of a 683-mile, 8-inch to 16-inch mainline pipeline and approximately 393 miles of 3-inch to 8-inch gathering pipelines. Rangeland Pipeline transports NGL mix, butane, condensate, light sweet crude oil and light sour crude oil either north to Edmonton or south to the U.S./Canadian border near Cutbank, Montana.

South Saskatchewan Pipeline. We own a 100% interest in the South Saskatchewan system. This pipeline consists of a 158-mile, 16-inch mainline from Cantuar to Regina, Saskatchewan and 184 miles of 4-inch to 12-inch gathering pipelines from the Rapdan area to Cantuar. South Saskatchewan Pipeline has capacity to transport approximately 68,000 barrels per day of heavy crude oil from gathering areas in southern Saskatchewan to Enbridge's mainline at Regina.

Canada NGL Pipelines

Co-Ed NGL Pipeline. We own and operate the Co-Ed NGL pipeline, which consists of 595 miles of 3-inch to 10-inch pipeline. This pipeline gathers NGL from approximately 27 field gas processing plants located in Alberta, including all of the NGL produced at the Cochrane Straddle Plant for delivery to our NGL facilities at Fort Saskatchewan. The Co-Ed NGL pipeline system has throughput capacity of approximately 72,000 barrels per day.

PPTC Pipeline. In August 2016, we acquired a 593-mile, 6-inch pipeline extending from Empress, Alberta to the Fort Whyte Terminal in Winnipeg, Manitoba (referred to herein as the Plains Petroleum Transmission Company Pipeline, or the "PPTC" Pipeline). The addition of this pipeline increased our current NGL pipeline capacity by an additional 15,500 barrels per day. The PPTC Pipeline gives us access to seven truck terminals and three rail loading facilities across the system, allowing for increased flexibility in rail operations.

Facilities Segment

Our Facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products, NGL and natural gas, as well as NGL fractionation and isomerization services and natural gas and condensate processing services. We generate revenue through a combination of month-to-month and multi-year agreements.

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

As of December 31, 2016, we owned, operated or employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 80 million barrels of crude oil and refined products storage capacity primarily at our terminalling and storage locations;
- approximately 32 million barrels of NGL storage capacity;

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- approximately 97 Bcf of natural gas storage working capacity;
- approximately 31 Bcf of owned base gas;
- nine natural gas processing plants located throughout Canada and the Gulf Coast area of the United States;
- a condensate processing facility located in the Eagle Ford area of South Texas with an aggregate processing capacity of approximately 120,000 barrels per day;
- eight fractionation plants located throughout Canada and the United States with an aggregate net processing capacity of approximately 211,000 barrels per day, and an isomerization and fractionation facility in California with an aggregate processing capacity of approximately 15,000 barrels per day;
- 34 crude oil and NGL rail terminals located throughout the United States and Canada. See "Rail Facilities" below for an overview of various terminals and "Supply and Logistics" regarding our use of railcars;
- six major marine facilities in the United States; and
- approximately 1,000 miles of active pipelines that support our facilities assets.

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, 2016, grouped by product and service type, with capacity and volume as indicated:

Crude Oil and Refined Products Storage Facilities	Total Capacity (MMBbls)
Cushing	23
LA Basin	8
Martinez and Richmond	5
Mobile and Ten Mile	5
Patoka	6
St. James	13
Yorktown (1)	5
Other (2)	15
	80

NGL Storage Facilities	Total Capacity (MMBbls)
Bumstead	3
Empress Area	5
Fort Saskatchewan	8
Sarnia Area	10
Other	6
	32

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

Natural Gas Processing Facilities (3)	Ownership Interest	Total Gas Inlet Volume (Bcf/d)	Net Gas Processing Capacity (Bcf/d)
United States Gulf Coast Area	100%	0.1	0.3
Canada	50-100%	1.9	7.1
		2.0	7.4

Condensate Stabilization Facility	Total Capacity (Bbls/d)
Gardendale	120,000

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NGL Fractionation and Isomerization Facilities	Ownership Interest	Total Spec Product [4] (Bbls/d)	Net Capacity (Bbls/d)
Empress	100%	6,300	28,300
Fort Saskatchewan	21-100%	28,300	67,800
Sarnia	62-84%	62,300	90,000
Shafter	100%	9,300	15,000
Other	82-100%	9,100	25,000
		115,300	226,100

Rail Facilities	Ownership Interest	Loading Capacity (Bbls/d)	Unloading Capacity (Bbls/d)
Crude Oil Rail Facilities	100%	380,000	350,000
	Ownership Interest	Number of Rack Spots	Number of Storage Spots
NGL Rail Facilities [5]	50-100%	335	1,515

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

(2) Amount includes approximately 2 million barrels of storage capacity associated with our crude oil rail terminal operations.

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

(4) Represents average volumes net to our share for the entire year.

(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.

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 physical trading hubs in the United States and the delivery point for crude oil futures contracts traded on the NYMEX. The Cushing Terminal has been designated by the NYMEX as an approved delivery location for crude oil delivered under the NYMEX light sweet crude oil futures contract. As the NYMEX delivery point and a cash market hub, the Cushing Interchange serves as a source of refinery feedstock for Midwest and Gulf Coast refiners and plays an integral role in establishing and maintaining markets for many varieties of foreign and domestic crude oil. The Cushing Terminal has access to all major inbound and outbound pipelines in Cushing and is designed to handle multiple grades of crude oil while minimizing the interface and enabling deliveries to connecting carriers at their maximum rate.

Since 1999, we have completed multiple expansions that have increased the capacity of the Cushing Terminal to a total of 23 million barrels. In 2016, we added approximately 1.6 million barrels of storage and we expect to add approximately 2.1 million barrels of storage capacity during 2017.

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

Martinez and Richmond Terminals. We own two terminals in the San Francisco, California area: a terminal at Martinez (which provides refined product and crude oil service) and a terminal at Richmond (which provides refined product and black oil service). Our San Francisco area terminals have 5 million barrels of combined storage capacity and are connected to area refineries through a network of owned and third-party pipelines that carry crude oil and refined products to and from area refineries. These terminals have dock facilities and our Richmond terminal is also able to receive product by rail. We have entered into a definitive agreement to sell these non-core terminals, which we expect to close in the first half of 2017.

Mobile and Ten Mile Terminal. We have a marine terminal in Mobile, Alabama (the "Mobile Terminal") that has current useable capacity of 2 million barrels. Approximately 4 million barrels of additional storage capacity is available at our nearby Ten Mile Facility, which is connected to our Mobile Terminal via a 36-inch pipeline. Of this capacity, approximately 3 million barrels supports our Facilities segment operations, with the remaining storage supporting our Transportation segment assets. 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. Our Ten Mile Facility is connected to our Pascagoula Pipeline.

Patoka Terminal. Our Patoka Terminal has 6 million barrels of storage capacity and includes an associated manifold and header system at the Patoka Interchange located in southern Illinois. Our terminal has access to all major pipelines and terminals at the Patoka Interchange. Patoka is a growing regional hub with access to domestic and foreign crude oil for certain volumes moving north on the Capline Pipeline as well as Canadian barrels moving south. In 2017, we expect to add approximately 0.5 million barrels of storage capacity to accommodate future pipeline connectivity.

St. James Terminal. We have 13 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. In addition, this facility includes a marine dock that is able to receive from, and load, tankers and barges and is also connected to our rail unloading facility. See "Rail Facilities" below for further discussion. In 2016, we added approximately 2.2 million barrels of storage capacity to the St. James terminal, which included connections to the rail unloading facility, marine dock and operational pipelines. In 2017, we expect to add approximately 0.4 million barrels of storage capacity.

Yorktown Terminal. We have 5 million barrels of storage for crude oil and refined products at our Yorktown facility located in Virginia, including approximately 1 million barrels of capacity for which we hold lease options (all of which have been exercised). The Yorktown facility has its own deep-water port on the York River with the capacity to service the receipt and delivery of product from ships and barges. This facility also has an active truck rack and rail capacity. See "Rail Facilities" below for further discussion.

Corpus Christi Terminal. We own a 50% interest in Eagle Ford Terminals, a joint venture with a subsidiary of Enterprise. Eagle Ford Terminals is currently developing a terminal in Corpus Christi, Texas that, when completed, will be capable of loading ocean going vessels at a rate of 40,000 barrels per hour. Initial storage capacity of the terminal will be approximately 1 million barrels. The facility will have access to production from both the Eagle Ford and the Permian Basin through the Eagle Ford joint venture pipeline and is expected to be placed in service in 2018.

NGL Storage Facilities

Bumstead. The Bumstead facility is located at a major rail transit point near Phoenix, Arizona. With 3 million barrels of useable capacity, the facility's primary assets include three salt-dome storage caverns, a 30-car rail track and six truck racks.

Empress Area. In August 2016, we acquired a network of seven NGL terminals (Fort Whyte, Moose Jaw, Rapid City, Stewart Valley, Dewdney, Empress and Richardson) with an aggregate useable storage capacity of 5 million barrels. Our Dewdney terminal includes two loading and unloading truck spots, with a rate of 18 trucks per day, as well as rail access to two loading racks with capacity of 20 cars per day. The Richardson terminal is connected to our recently acquired PPTC Pipeline and includes two loading truck spots with a rate of 24 trucks per day. Our Stewart Valley, Moose Jaw and Rapid City propane terminals each have one truck loading rack. The Fort Whyte terminal is equipped with a truck terminal containing two loading spots capable of loading 40 trucks per day, and a rail loading terminal with loading capacity of 13 railcars per day.

Fort Saskatchewan. The Fort Saskatchewan facility is located approximately 16 miles northeast of Edmonton, Alberta in one of the key North American NGL hubs. The facility is a receipt, storage, fractionation and delivery facility for NGL and is connected to other major NGL plants and pipeline systems in the area. The facility's primary assets include 22 storage caverns with approximately 8 million barrels in useable storage capacity. The facility includes assets operated by us and assets operated by a third-party. Our ownership in the various facility assets ranges from approximately 21% to 100%. See the section entitled "—NGL Fractionation and Isomerization Facilities" below for additional discussion of this facility.

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In 2013, we began upgrading our Fort Saskatchewan storage capacity as part of a multi-phase expansion. The first phase of the expansion added 2.4 million barrels of new brine pond capacity and two new NGL storage caverns each with a capacity of 350,000 barrels; the first NGL cavern was completed in July 2016, and the second cavern in December 2016. We will convert approximately 3 million barrels of NGL mix storage to propane, butane and condensate storage by the end of the first quarter of 2017. The second phase of the project, which is expected to be completed in 2017, will see the development of 2.7 million barrels of new brine pond capacity and two new ethane caverns totaling 1.6 million barrels of capacity which are supported by long-term commitments from third parties.

Sarnia Area. Our Sarnia Area facilities consist of (i) our Sarnia facility, (ii) our Windsor storage terminal and (iii) our St. Clair terminal. The Sarnia facility is a large NGL fractionation, storage and shipping facility located on a 380-acre plant site in the Sarnia Chemical Valley. There are 36 multi-product railcar loading spots, 7 multi-product truck loading racks and a network of 14 pipelines providing product delivery capabilities to our Windsor and St. Clair terminal facilities, in addition to refineries, chemical plants and other pipeline systems in the area. The Sarnia facility has approximately 5 million barrels of useable storage capacity. In 2012, we initiated a brine disposal program to facilitate the removal of excess brine via truck from our Sarnia facility. The project increased useable NGL storage capacity at the facility by 1 million barrels in 2015, and further by approximately 1 million barrels in 2016.

The Windsor storage terminal in Windsor, Canada, is a pipeline hub and underground storage facility. The facility is served by three of our receipt/dispatch pipelines and rail and truck offloading. There are eight storage caverns on site with a useable capacity of approximately 3 million barrels. The terminal assets include 16 multi-product rail tank car loading spots and a propane truck loading rack.

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

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, 2016, we had an aggregate working gas capacity of approximately 97 Bcf in service. Our facilities have aggregate permitted 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 have 22 direct interconnects with third party interstate pipelines, industrial facilities and gas fired power plants, serving markets in the Gulf Coast, Midwest, Mid-Atlantic, Northeast, and Southeast regions of the United States and the Southeastern portion of Canada.

In January 2017, we executed a definitive agreement to sell our Bluewater natural gas storage facility located in Michigan. We expect this transaction to close in the first half of 2017, subject to customary closing conditions.

Natural Gas Processing Facilities

We own and/or operate four straddle plants and two field gas processing plants located in Western Canada. Through our August 2016 acquisition of the Empress straddle plant, we added 2.4 Bcf per day of gross NGL processing capacity with the ability to extract ethane and NGL liquids from TransCanada main lines. Cumulatively, our straddle plants have an aggregate net natural gas processing capacity of approximately 7.1 Bcf per day and a long-term liquids supply contract relating to a third-party owned straddle plant with gross processing capacity of approximately 2.5 Bcf per day. We also own and operate three natural gas processing plants located in Louisiana and Alabama with an aggregate natural gas processing capacity of approximately 0.3 Bcf per day.

NGL Fractionation and Isomerization Facilities

Empress. In August 2016, we acquired the Empress fractionation facility, which is connected to and receives liquids from our Empress straddle plant and has a fractionation capacity of approximately 28,000 barrels per day of propane, butane and condensate. The facility is capable of producing spec NGL products and connects to our recently acquired PPTC Pipeline network. See “Empress Area” under “NGL Storage Facilities” above for a description of the assets connected to the PPTC Pipeline.

Fort Saskatchewan. Our recently expanded Fort Saskatchewan fractionation facility has an inlet capacity of 85,000 barrels per day and produces spec propane, butane, condensate and a C3/C4 mix, which is sent to our Sarnia facility for further fractionation. We are in the process of adding a merox sweetening unit that will increase our ability to handle a variety of feed streams providing more flexibility and flow assurance. This final stage of the expansion is expected to be completed in late 2017 and is supported by long-term commitments from third parties. Through our 21% ownership in the Keyera Fort Saskatchewan fractionation plant, we have additional fractionation capacity, net to our share, of approximately 17,000 barrels per day.

Sarnia. The Sarnia Fractionator is the largest fractionation plant in Eastern Canada and receives NGL feedstock from the Enbridge Pipeline and from refineries, gas plants and chemical plants in the area. The fractionation unit has a net useable capacity of 90,000 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 15,000 barrels per day including NGL fractionation capacity of approximately 12,000 barrels per day.

The facility also includes an approximate 40-mile NGL pipeline system capable of delivering up to 20,000 barrels per day from California Resources Corporation’s Elk Hills Gas plant to our Shafter facility, equipped with storage capacity of 30,000 barrels and 10,000 barrels per day of rail capacity.

Condensate Processing Facility

Our Gardendale condensate processing facility located in La Salle County, Texas is designed to extract natural gas liquids from condensate. The facility is adjacent to our Gardendale terminal and rail facility and is connected to a third-party pipeline that delivers NGL to Mont Belvieu. The facility has a total processing capacity of 120,000 barrels per day and useable storage capacity of 160,000 barrels. Throughput at the Gardendale processing facility is supplied by long-term commitments from producers.

Rail Facilities

Crude Oil Rail Loading Facilities

We own crude oil and condensate rail loading terminals with a combined loading capacity of approximately 380,000 barrels per day. These facilities are located at or near Carr, Colorado; Tampa, Colorado; Gardendale, Texas; McCamey, Texas; Manitou, North Dakota; Van Hook, North Dakota; and Kerrobert, Saskatchewan.

Crude Oil Rail Unloading Facilities

We own three crude oil rail unloading terminals that have a combined unloading capacity of approximately 350,000 barrels per day. Our terminal at St. James, Louisiana is connected to our rail unloading facility that has an unload capacity of 140,000 barrels per day. Our Yorktown, Virginia rail facility receives unit trains and has an unload capacity of approximately 140,000 barrels per day, and our Bakersfield, California rail facility receives unit trains and has permitted capacity to unload 70,000 barrels per day.

NGL Rail Facilities

In April 2016, we completed the Fort Saskatchewan rail terminal which consists of 20 rack spots capable of loading 60 cars per day of propane. We have initiated projects to add butane loading and condensate offloading capacity at the facility, which is expected to be in service in the third quarter of 2018.

We also own 26 operational NGL rail facilities strategically located near NGL storage, pipelines, gas production or propane distribution centers throughout the United States and Canada. Our NGL rail facilities currently have 335 railcar rack spots and 1,515 railcar storage spots, and we have the ability to switch our own railcars at six of these terminals.

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

We generally characterize a portion of our baseline segment results generated by our Supply and Logistics segment as fee equivalent. This portion of the segment results 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 results associated with a portion of the other activities we conduct in the Supply and Logistics segment is influenced by overall market structure and the degree of market volatility, as well as variable operating expenses. The majority of activities that are carried out within our Supply and Logistics segment are designed to produce stable baseline results in a variety of market conditions, while at the same time providing upside potential associated with opportunities inherent in volatile market conditions (including opportunities to benefit from fluctuating differentials). These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies. The tankage that is used to support our arbitrage activities positions us to capture margins in various market conditions. During a transitional market, however, our Supply and Logistics segment may not be able to fully recover its costs on certain transactions in order to capture incremental barrels into our overall value chain. See "—Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model" below for further discussion.

In addition to hedged working inventories associated with its merchant activities, as of December 31, 2016, our Supply and Logistics segment also owned significant volumes of crude oil and NGL classified as long-term assets and linefill or minimum inventory requirements and employed a variety of owned or leased physical assets throughout the United States and Canada, including approximately:

- 14 million barrels of crude oil and NGL linefill in pipelines owned by us;
- 5 million barrels of crude oil and NGL linefill in pipelines owned by third parties and other long-term inventory;
- 820 trucks and 1,065 trailers; and
- 10,660 crude oil and NGL railcars.

In connection with its operations, our 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 fees are based on posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates. However, certain terminalling and storage rates recognized within our Facilities segment are discounted to our Supply and Logistics segment to reflect the fact that these services may be canceled on short notice to enable the Facilities segment to provide services to third parties, generally under longer term arrangements.

The following table shows the average daily volume of our supply and logistics activities for the year ended December 31, 2016:

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	Volumes (MBbls/d)
Crude oil lease gathering purchases	894
NGL sales	259
Waterborne cargos	7
Supply and Logistics activities total	1,160

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 with remaining terms extending up to nine years. We utilize our truck fleet, railcars and pipelines as well as leased railcars, third-party pipelines, trucks and barges to transport the crude oil to market. From time to time, we enter into various types of purchase and exchange transactions including fixed price purchase contracts, collars, financial swaps and crude oil and NGL-related futures contracts as hedging devices.

We purchase NGL from producers, refiners and other NGL marketing companies under contracts that typically have ranged from immediate delivery to one year in term. In the last few years, we have implemented an increasing number of contracts with longer terms to ensure 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 hub locations, rail facilities and dock or load port 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 individual refinery demand for specific grades of crude oil, area market price structures, location of customers, various modes and availability of transportation facilities to deliver crude oil and NGL to our customers.

We sell our crude oil to major integrated oil companies, independent refiners, exporters and other resellers in various types of sale and exchange transactions. Our crude oil sales contracts generally range in term from thirty-day evergreen to five years, with the majority ranging from thirty days to one year. We sell NGL primarily to propane and refined product retailers, petrochemical companies and refiners, and limited volumes to other marketers. The majority of our NGL contracts generally span a term of one year. For contracts greater than one year, pricing mechanisms are put in place to ensure any cost escalations are accounted for as well as annual price negotiations occur to ensure both the buyer and seller remain at market based pricing. We establish a margin for the crude oil and NGL we purchase by entering into physical sales contracts with third parties, or by entering into a future delivery obligation with respect to futures contracts on the NYMEX, ICE or over-the-counter exchanges. Through these transactions, we seek to maintain a position that is substantially balanced between purchases and sales and future delivery obligations. From time to time, we enter into various types of sale and exchange transactions including fixed price delivery contracts, collars, financial swaps and crude oil and NGL-related futures contracts as hedging devices.

Crude Oil and NGL Exchanges. We pursue exchange opportunities to enhance margins throughout the gathering and marketing process. When opportunities arise to increase our margin or to acquire a grade, type or volume of crude oil or NGL that more closely matches our physical delivery requirement, location or the preferences of our customers, we exchange physical crude oil or NGL, as appropriate, with third parties. These exchanges are effected through contracts called exchange or buy/sell agreements. Through an exchange agreement, we agree to buy crude oil or NGL that differs in terms of geographic location, grade of crude oil or type of NGL, or physical delivery schedule from crude oil or NGL we have available for sale. Generally, we enter into exchanges to acquire crude oil or NGL at locations that are closer to our end markets, thereby reducing transportation costs and increasing our margin. We also exchange our crude oil to be physically delivered at a later date, if the exchange is expected to result in a higher margin net of storage costs, and enter into exchanges based on the grade of crude oil, which includes such factors as sulfur content and specific gravity, in order to meet the quality specifications of our physical delivery contracts. See Note 2 to our Consolidated Financial Statements for further discussion of our accounting for exchange and buy/sell agreements.

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

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

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

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

We also have credit risk exposure related to our sales of NGL (principally propane); however, because our sales are typically in relatively small amounts to individual customers, we do not believe that these transactions pose a material concentration of credit risk. Typically, we enter into annual contracts to sell NGL on a forward basis, as well as to sell NGL on a current basis to local distributors and retailers. In certain cases our NGL customers prepay for their purchases, in amounts ranging up to 100% of their contracted amounts.

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

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

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

Crude oil, NGL and natural gas commodity prices have historically been very volatile. For example, since the mid-1980s, NYMEX West Texas Intermediate (“WTI”) crude oil benchmark prices have ranged from a low of approximately $10 per barrel during 1986 to a high of over $147 per barrel during 2008. During 2016, WTI crude oil prices traded within a range of approximately $26 to $54 per barrel. There is also volatility within the propane and butane markets as seen through the North American benchmark price located at Mont Belvieu, Texas. Specifically, propane prices have ranged from a low of approximately 40% of the WTI benchmark price for crude oil in 2016 to a high of approximately 81% of the WTI benchmark price for crude oil in 2000. Butane has seen a price range from a low of approximately 53% of the WTI benchmark price for crude oil in 2016 to a high of approximately 99% of the WTI benchmark price for crude oil in 2016.

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

Base level segment results 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 results may be adversely affected during certain transitional periods as discussed further below, our crude oil and NGL supply, logistics and distribution operations are not directly affected by the absolute level of prices, but are affected by overall levels of supply and demand for crude oil and NGL and relative fluctuations in market-related indices.

In developing our business model and allocating our resources among our three segments, we attempt to anticipate the impacts of shifts between supply-driven markets and demand-driven markets, seasonality, cyclicality, regional surpluses and shortages, economic conditions and a number of other influences that can cause volatility and change market dynamics on a short, intermediate and long-term basis. Our objective is to position the Partnership such that our overall annual base level of cash flow is not materially adversely affected by the absolute level of energy prices, shifts between demand-driven markets and supply-driven markets or other similar dynamics. Beginning in the second half of 2014 to present, however, the market has experienced impacts from aggressive competition and overbuilt infrastructure in certain regions, which has caused supply and demand imbalances and price volatility. In some of the areas where we operate, there has been significantly increased competition for marginal or incremental volumes from shippers on third party pipelines who have committed to ship more production than they have and are purchasing barrels in the market for shipment on the applicable third party pipeline in satisfaction of their transportation commitments, often doing so at a loss because the loss on sale of the purchased crude oil will be less than the amount of the take-or-pay obligation on the pipeline. This type of activity has put downward pressure on volumes and margins across our three business segments. This transitioning crude oil market presents challenges to both us and the overall midstream industry, and while we believe our integrated business model and diversification of our asset base among varying regions and demand-driven and supply-driven markets gives us competitive advantages, we may see a lower level of cash flow than we would have otherwise experienced. In addition, increased competition and compressed differentials may drive lower volumes and lower unit margins in parts of our business, particularly our Supply and Logistics segment. Also, during such transitional markets, our Supply and Logistics segment may not be able to fully recover its costs on certain transactions in order to capture incremental barrels into our overall value chain creating the opportunity to provide profitability at the company level.

While recent market conditions have been challenging, we believe the complementary, integrated nature of our business activities and diversification of our asset base among varying regions and demand-driven and supply-driven markets generally provides us with the opportunity to generate a base level of cash flow in a variety of market scenarios. In addition to providing the opportunity to generate a base level of cash flow, this approach is also intended to provide opportunities to realize incremental margin during volatile market conditions. For example, if crude oil prices are high relative to historical levels, we may hedge some of our expected pipeline loss allowance barrels, and if crude oil prices are low relative to historical prices, we may hedge a portion of our anticipated diesel purchases needed to operate our trucks and barges. Also, during periods when supply exceeds the demand for crude oil, NGL or natural gas in the near term, the market for such product is often in contango, meaning that the price for future deliveries is higher than current prices. In a contango market, entities that have access to storage at major trading locations can purchase crude oil, NGL or natural gas at current prices for storage and simultaneously sell forward such products for future delivery at higher prices.

The combination of fee-based cash flow from our Transportation and Facilities segments, complemented by a number of diverse, flexible and generally counter-balanced sources of cash flow within our Supply and Logistics segment is intended to provide us with the opportunity to generate a base level of cash flow and provide 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.

During certain transitional periods, such as this extended period of lower crude oil prices, the ability to generate above base line performance is challenging, and taking into account the over-capacity of midstream assets that currently exists in most crude oil producing regions, generating even baseline level performance will be challenging. See "Global Petroleum Market Overview " above for additional discussion regarding market conditions.

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.

Our policy is generally to structure our purchase and sales contracts so that price fluctuations do not materially affect our operating income, and not to acquire and hold physical inventory or derivatives for the purpose of speculating on outright commodity price changes. Although we seek to maintain a position that is substantially balanced within our supply and logistics activities, we purchase crude oil, NGL and natural gas from thousands of locations and may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions and other uncontrollable events that may occur. When unscheduled physical inventory builds or draws do occur, they are monitored constantly and managed to a balanced position over a reasonable period of time. This activity is monitored independently by our risk management function and must take place within predefined limits and authorizations.

Geographic Data; Financial Information about Segments

See Note 19 to our Consolidated Financial Statements.

Customers

Marathon Petroleum Corporation and its subsidiaries accounted for 18%, 17% and 17% of our revenues for the years ended December 31, 2016, 2015 and 2014, respectively. ExxonMobil Corporation and its subsidiaries accounted for 14%, 13% and 15% of our revenues for the years ended December 31, 2016, 2015 and 2014, respectively. Phillips 66 Company and its subsidiaries accounted for 11% of our revenues for the year ended December 31, 2016. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2016. 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 14 to our Consolidated Financial Statements.

Competition

Competition among pipelines is based primarily on transportation charges, access to producing areas and supply regions and demand for 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, together with the fact that many of the producing basins in the United States and Canada currently have excess take-away capacity (whether by pipeline or rail), generally make it less likely that new competing pipeline systems comparable in size and scope to our larger pipeline systems (and excluding those already publicly announced to be under development or construction) will limit the number of new pipeline projects over the next few years. However, there are currently third-party owned pipelines or owners with joint venture pipelines with excess capacity in the vicinity of our operations that expose us to significant competition based on the relatively low cost of moving an incremental barrel of crude oil or NGL. In the current environment, such competition for marginal or incremental volumes has been exacerbated in some areas by shippers on third party pipelines who have committed to ship more production than they own or have secured under contract and are purchasing barrels in the market and shipping them on the applicable third party pipeline in satisfaction of their transportation commitment. This type of activity reduces the pool of incremental barrels that would otherwise be available for transport on our pipelines. 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 and terminalling companies, other NGL processing and fractionation companies, the major integrated oil companies and their marketing affiliates, independent gatherers, private equity backed entities, 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 fines and penalties, expose us to civil and criminal claims, and cause us to incur significant costs and expenses. In all material respects, we believe that we are in substantial compliance with the various laws, rules and regulations that apply to our assets, operations and business activities; however, we can provide no assurances in that regard. See Item 1A. "Risk Factors—Risks Related to PAA's Business—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." 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. We can provide no assurance that the increased costs associated with any new or proposed laws, rules or regulations will not be material. We may at any time also be required to apply significant resources in responding to governmental requests for information and/or enforcement actions.

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. 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, health and safety laws and regulations to which our operations are subject.

Pipeline Safety/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

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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 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 $89 million in 2016, $107 million in 2015 and $107 million in 2014. Based on currently available information, our preliminary estimate for 2017 is that we will incur approximately $95 million in capital expenditures and approximately $35 million in operational expenditures associated with our required pipeline integrity management program. Significant additional expenses could be incurred if new or more stringently interpreted pipeline safety requirements are implemented. In addition to required activities, our integrity management program includes several voluntary, multi-year initiatives designed to prevent incidents. Costs incurred for such activities were approximately $48 million in 2016, $33 million in 2015 and $21 million in 2014, and our preliminary estimate for 2017 is that we will incur approximately $50 million of such costs.

In 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the "2011 Act") became effective. Under the 2011 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 2011 Act reauthorized 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 2011 Act have the potential to cause owners and operators of pipeline facilities to incur significant capital expenditures and/or operating costs.

The Securing America's Future Energy: Protecting Infrastructure of Pipelines and Enhancing Safety Act ("SAFE PIPES Act") was signed into law on June 22, 2016. This bill imposes a number of requirements on the industry and PHMSA, but the key provisions include: (i) reauthorization of PHMSA through fiscal year 2019, (ii) requirements for reports to Congress on the status of rulemaking efforts and certain specific information gathering efforts, (iii) a requirement that PHMSA initiate new rulemaking for underground natural gas storage facilities, (iv) a requirement to convene a work group on the development of a voluntary information sharing program; and (v) the granting of authority to the DOT to issue industry-wide emergency orders under certain circumstances.

The pending rule-making efforts that are required by the SAFE PIPES Act, and that could materially affect the operation of pipeline operators, include: (i) expansion of integrity management programs beyond high-consequence areas, (ii) additional regulation of pipeline leak detection systems and (iii) the use of shut-off valves and excess flow valves in certain applications. We will monitor the rule-making resulting from the SAFE PIPES Act, as well as the reports PHMSA is obligated to provide to Congress to better understand the potential impact to our operations. At this time we cannot predict the full impact to our operations or the potential additional cost of compliance.

In October 2015, PHMSA published a Notice of Proposed Rulemaking ("NPRM") in the Federal Register proposing to make changes to the hazardous liquid pipeline safety regulations. PHMSA is proposing to make the following changes to the regulations:

- Extend reporting requirements to all hazardous liquid gravity and gathering lines;
- Require inspections of pipelines in areas affected by extreme weather, natural disasters, and other similar events, and periodic inline integrity assessments of pipelines that are located outside of high consequence areas of at least once every ten years;
- Use of leak detection systems on hazardous liquid pipelines in all locations;
- Modify the provisions for making pipeline repairs;

- Require that all pipelines subject to the integrity management requirements be capable of accommodating inline inspection tools within 20 years; and
- Clarifications to improve certainty and compliance to certain existing regulations.

PHMSA announced the regulatory text of the final rule on January 13, 2017; however, the complete text was not published in the Federal Register prior to the regulatory freeze put in place by the incoming administration on January 24, 2017. The regulatory freeze was instituted to allow the incoming administration the opportunity to review all pending rules.

The rule will go into effect six months after publication in the Federal Register. We do not currently believe this rule will have a significant adverse financial impact on our operations.

If approved by PHMSA, states may assume responsibility for enforcing federal interstate pipeline regulations as agents for PHMSA and conduct inspections of interstate pipelines. In practice, states vary in their authority and capacity to address pipeline safety.

The California Governor signed into law the following three bills on October 8, 2015 related to pipeline safety:

- The Oil Spill Response Bill allows volunteer cleanup crews to be paid as contractors, requires oil skimmers to be placed along the coastline at all times, and prohibits the use of dispersants until the EPA issues rules on dispersant safety.
- The Pipeline Safety: Inspections Bill (SB 295) mandates annual pipeline inspections commencing January 1, 2017, with the State Fire Marshal responsible for annually inspecting all intrastate pipelines and operators of intrastate pipelines under the jurisdiction of the State Fire Marshal.
- The Oil Spill Response: Environmentally and Ecologically Sensitive Areas Bill (AB 864) requires automatic shut-offs for pipelines located in environmentally sensitive areas.

The SB 295 rulemaking efforts were completed in 2016 and the annual pipeline inspection requirements commence in 2017. Efforts to draft and implement regulations to adopt the provisions of AB 864 continue and are expected to be finalized by July 2017. We cannot currently predict the impact and costs of these new laws, and any associated regulations, on our operations.

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, our costs associated with this program were approximately $29 million, $33 million and $32 million in 2016, 2015 and 2014, respectively. For 2017, we have budgeted approximately $40 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 (“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.

The Pipeline Safety Act, SC 2015, c. 21 (the “Pipeline Safety Act” or the “Act”) came into force in June 2016, amending the National Energy Board Act and the Canada Oil and Gas Operations Act in order to strengthen the safety and security of pipelines regulated under those acts. It reinforces the “polluter pays” principle, such that operators of pipelines are liable for costs and damages for all unintended or uncontrolled releases of oil, gas, or other substances. The Act introduces absolute liability for costs and damages up to $1 billion from an uncontrolled release of oil, gas or other commodity from a major pipeline (i.e. those with capacity over 250,000 barrels per day). Additionally, operators will be required to maintain the financial resources necessary to meet the applicable absolute liability obligations imposed under the Act. Finally, the Act imposes requirements with respect to abandoned pipelines, including an obligation to maintain adequate funds to pay for abandonment costs. The total transport capacity of our pipelines regulated by the NEB exceeds 250,000 barrels per day so financial instruments in the form of lines of credit and insurance verification were filed with the NEB. The Pipeline Safety Act also amended the pipeline damage prevention provisions of the National Energy Board Act and regulations for pipeline damage prevention came in effect June 2016. Potential operational requirements and costs may be incurred around depth of cover information and mitigation with landowners, crossings and encroachments, turnaround timelines for responding to dig requests near pipelines and land use monitoring for adjacent lands to the pipeline right-of-way. The cost impact of the Pipeline Safety Act on us is not expected to be material.

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In addition to required activities, our Canadian integrity management program includes several voluntary, multi-year programs designed to prevent incidents, such as upgrades to our operating and maintenance programs and systems and upgrades to our pipeline watercourse crossing integrity program. Between such required and elective activities, we spent approximately $56 million, $66 million and $66 million in 2016, 2015 and 2014, respectively. Our preliminary estimate for 2017 is approximately $75 million.

We cannot predict the potential costs associated with additional, future regulation. Significant additional expenses could be incurred, and additional operational requirements and constraints could be imposed, if new or more stringently interpreted pipeline safety requirements are implemented.

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.

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.

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 waste under RCRA may be revisited and our wastes subject to more rigorous and costly disposal requirements, resulting in additional capital expenditures or operating expenses. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address the EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from RCRA regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary.

Hazardous Substances

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

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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. In March 2016, the EPA proposed revisions to the Risk Management Plan ("RMP") rules, including requirements for the use of third party compliance audits, root cause analyses for facilities that experience releases, process hazard analyses and enhanced information-sharing provisions. OSHA has announced that it is considering similar revisions to the PSM rule, but, to date, has not issued an NPRM.

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 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 may 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. In October 2015, the EPA promulgated a revised national ambient air standard for ozone. While full implementation of the standard may take a number of years, the revised standard could make air permits for sources of volatile organic compounds (such as crude oil tank farms) more difficult to obtain in some areas. In addition, in June 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and control requirements.

Our Canadian operations are subject to federal and provincial air emission regulations. 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 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.

As a result of the changing requirements in both Canada and the United States such as those mentioned above, 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. We can provide no assurance that future compliance obligations will not have a material adverse effect on our financial condition or results of operations.

Climate Change Initiatives

United States

The EPA has adopted rules for the reporting of carbon dioxide, methane and other greenhouse gases ("GHG") from certain sources. 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 our facilities and activities.

The EPA has also promulgated regulations establishing Title V and Prevention of Significant Deterioration permitting requirements for certain 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” (“BACT”) to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they emit quantities of GHGs that trigger the requirements of these regulations. For facilities such as ours, BACT will normally take the form of enhanced energy efficiency measures rather than post-combustion GHG capture requirements. We do not anticipate that the imposition of enhanced energy efficiency requirements will have a material adverse effect on the cost of our operations.

In June 2016, the EPA finalized regulations affecting new, modified and reconstructed sources of air emissions in the oil and natural gas sector that require significant reductions in fugitive methane emissions from certain upstream and midstream oil and gas facilities. These new rules also require operators to implement fugitive emission leak detection and repair requirements for compressor stations. We do not expect the cost of complying with these rules to have a material effect on the cost of our operations.

California has implemented a GHG cap-and-trade program, authorized under Assembly Bill 32 (“AB32”). Through 2014, California’s cap-and-trade program has only applied to large industrial facilities. The California Air Resources Board has published a list of facilities that are subject to this program. At this time, the list only includes one of our facilities, the Lone Star Gas Liquids facility in Shafter, California because it is a significant combustion source. As a result, compliance instruments for GHG emissions have been purchased since 2013.

On January 1, 2015, the AB32 regulations for the first time covered finished fuel providers and importers. California finished fuels providers (refiners and importers) were required to purchase GHG emission credits for finished fuel sold in or imported into California. Plains Marketing was included in this portion of the regulation due to propane imports and completed its first year of compliance in 2016. The rules implementing the AB32 program were finalized in December 2011. The compliance requirements of the GHG cap-and-trade program through 2020 are being phased in. The California Air Resources Board is currently developing a scoping plan for AB32 compliance obligations after the year 2020. We will be reporting associated GHG emissions for finished fuels imported and exported across California borders and will be subject to the cap and trade program in 2016.

Executive Order B-30-15 was signed by California’s Governor in mid-year 2015. This Executive Order requires a 40% reduction in GHG emissions from the 1990 baseline level by 2030. The current 2020 goals for GHG emissions reductions are at 15% below the 1990 baseline level. Compliance with this reduction requirement may necessitate the lowering of the threshold for industrial facilities required to participate in the GHG cap and trade program. This may increase the number of PAA facilities subject to this program.

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

In December 2015, the Paris Agreement was signed at the 21st annual Conference of Parties to the United Nations Framework Convention on Climate Change ("UNFCCC"). The Paris Agreement, which came into effect in November 2016, requires signatory parties to develop and implement carbon emission reduction policies with a goal of limiting the rise in average global temperatures to 2°C or less. This Agreement is likely to become a significant driver for future potential GHG reduction programs in the United States and Canada.

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.

Canada

Federal Regulations. Along with 194 other countries, Canada is a signatory to the UNFCCC “Durban Platform” committing it to develop a legally binding agreement to reduce GHG emissions by 2020. Since 2004, large emitters of GHG were required to report their emissions under the Canadian Greenhouse Gas Emissions Reporting Program. Three PMC facilities meet the current 50kt/y reporting threshold.

The federal Department of Environment and Climate Change is proposing to lower the reporting threshold for all facilities from 50kt/y to 10 kt/y. The enactment of this proposal would result in more PMC facilities being required to prepare annual reports of their emissions. The associated costs with this requirement would not be considered material.

In October 2016, the Government of Canada proposed a pan-Canadian approach to pricing carbon pollution requiring all Canadian provinces and territories to have carbon pricing in place by 2018. The provinces and territories will have flexibility in deciding how they implement carbon pricing either by placing a direct price on carbon pollution or adopting a cap-and-trade system. The price on carbon pollution will start at $10/tonne in 2018 and rise by $10 a year to reach $50/tonne in 2022.

Provincial Regulations

Ontario. In February 2015, the Ontario Ministry of Environment and Climate Change issued a discussion paper that identified carbon pricing as a critical action necessary to reduce emissions of greenhouse gases. In April 2015, the Ontario government announced it would be implementing a GHG cap and trade program, which would be implemented through the Western Climate Initiative (WCI), which includes Quebec and California. Mandatory participants for the program will be responsible for their emissions starting on January 1, 2017.

PMC’s facility at Sarnia is considered to be a mandatory participant in the program (threshold >25,000 tonnes GHG emissions). At this early stage of the program, it is not possible to predict any material increases in compliance costs or additional operating restrictions.

Alberta. The Alberta Climate Change and Emissions Management Act provides a framework for managing GHG emissions by reducing specified gas emissions to 50% of 1990 levels by December 31, 2020. The accompanying Specified Gas Emitters Regulation imposes GHG emissions limits on large emitters and requires reductions in GHG emissions intensity. Since the regulation came into effect, PMC has two facilities (Fort Saskatchewan Storage and Fractionation Facility and Empress VI) which currently do not meet the reduction obligation. As such, PMC has been required to submit compliance payments to the Climate Change Emissions Management Fund (the “CCEMC”). CCEMC will increase from $30 per tonne (from $20 in 2016) of CO2 over a facility’s budget in 2017, which will increase our operating costs at these two facilities.

On May 24, 2016, the Government of Alberta introduced Bill 20: the Climate Leadership Implementation Act, which implements a carbon levy on Alberta businesses previously announced under the Plan. Subject to certain exemptions, the Act applies a carbon levy to all sales and imports of fuel. PMC has registered and received specific exemptions for its Alberta facilities until January 1, 2023. The combined effect of these Alberta climate change enactments is not expected to be material.

Saskatchewan. The Management and Reduction of Greenhouse Gases Act received royal assent on May 20, 2010 and set 20% GHG emission reduction targets below 2006 levels by 2020, but no regulations to implement the targets have been passed by the provincial government to date. The provincial government continues discussions with the federal government on implementation.

Water

The U.S. 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/Integrity Management" above and Note 17 to our Consolidated Financial Statements. Federal, state and provincial regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with discharge permits or other requirements of the CWA.

The U.S. 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. 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.

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 over 35 years, the Corps has authorized construction, maintenance and repair of pipelines under a streamlined nationwide permit program known as Nationwide Permit 12 (“NWP”). The NWP program is supported by strong statutory and regulatory history and was originally approved by Congress in 1977. From time to time, environmental groups have challenged the NWP program; however, to date, federal courts have upheld the validity of NWP program under the CWA. We cannot predict whether future lawsuits will be filed to contest the validity of NWP; however, in the event that a court wholly or partially strikes down the NWP program, which we believe to be unlikely, we could face significant delays and financial costs when seeking project approvals from the Corps.

In May 2015, the EPA published a final rule that attempted to clarify federal jurisdiction under the CWA over waters of the United States, but a number of legal challenges to this rule are pending, and implementation of the rule has been stayed nationwide. To the extent the rule expands the scope of the CWA’s jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

The Corps completed their five-year review and update of the NWPs in 2016, publishing the final version of the revised NWPs in the Federal Register on January 6, 2017. The revised NWPs will be effective on March 19, 2017. Changes to NWP 12, which applies to linear projects such as pipelines, could impact both the time to obtain project authorization under NWP 12 and the cost to comply with the revised conditions.

Endangered Species

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

Other Regulation

Transportation Regulation

Our transportation activities are subject to regulation by multiple governmental agencies. Our historical operating costs reflect the recurring costs resulting from compliance with these regulations. The following is a summary of the types of transportation regulation that may impact our operations.

General Interstate Regulation in the United States. 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 in the United States. 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.

U.S. 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, 2016, the annual index adjustment for the five year period ending June 30, 2021 will equal the producer price index for finished goods for the applicable year plus an adjustment factor of 1.23%. 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.

Pipeline Rate Regulation in the United States. The FERC historically 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. FERC issued an Advance Notice of Proposed Rulemaking on October 20, 2016 that addressed issues related to FERC's indexing methodology and liquids pipeline reporting practices. If implemented, the proposals in this rulemaking could affect the profitability of certain liquids pipelines. On December 15, 2016, FERC issued a Notice of Inquiry regarding certain matters related to FERC's income tax allowance policy. Parties are currently submitting comments in response to this notice, and FERC could, after review of those comments, decide to propose changes to its current policy.

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.

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 and (vi) operation and equipment safety. We are also subject to OSHA with respect to our trucking operations.

Canada

Our trucking assets in Canada are subject to regulation by both federal and provincial transportation agencies in the provinces in which they are operated. These regulatory agencies do not set freight rates, but do establish and administer rules and regulations relating to other matters including equipment, facility inspection, reporting and safety. We are licensed to operate both intra- and inter-provincially under the direction of the National Safety Code

(“NSC”) that is administered by Transport Canada. Our for-hire service is primarily the transportation of crude oil, condensates and NGL. We are required under the NSC to, among other things, monitor: (i) driver operations, (ii) log book maintenance, (iii) truck manifest preparations, (iv) safety placard placement on the trucks and trailers, (v) operation and equipment safety and (vi) many other aspects of trucking operations. We are also subject to Occupational Health and Safety regulations with respect to our trucking operations.

On June 1, 2016, the Transportation of Dangerous Goods (“TDG”) Regulations were amended. The amendments to the TDG regulations concern volume thresholds for reporting flammable product releases. For many products transported by PMC, the volume threshold for reporting changed from 200 litres (52.8 gallons) to ‘any volume’ that could endanger public safety. While this change in legislation may result in an increase in the number of reportable releases, it is not expected to have a financial impact (penalties or remediation).

Railcar Regulation

We own and operate a number of railcar loading and unloading facilities in the United States and Canada. In connection with these rail terminals, we own and lease a significant number of railcars. 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.

Railcar accidents involving trains carrying crude oil from North Dakota's Bakken shale formation have led to increased regulatory scrutiny. 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. In May 2015, PHMSA adopted a final rule that, among other things, imposes a new tank car design standard, a phase out by as early as January 2018 for older DOT-111 tank cars that are not retrofitted, and a classification and testing program for unrefined petroleum based products, including crude oil. We expect our railcar fleet to be in compliance with such requirements. The rule also includes new operational requirements such as speed restrictions. In December 2015, Congress passed the Fixing America's Transportation ("FAST") Act which was subsequently signed by the President. This legislation clarified the parameters around the timeline and requirements for railcars hauling crude oil in the United States.

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

Cross Border Regulation

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

Market Anti-Manipulation Regulation

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

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

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

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

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 $1,193,970 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.

In December 2016, PHMSA issued an interim final rule ("IFR") that establishes minimum federal standards for underground natural gas storage facilities. The IFR imposes new requirements on "downhole facilities," including wells, wellbore tubing and casings at underground natural gas storage facilities. The IFR addresses construction, maintenance, risk management and integrity management procedures for these facilities and includes registration and reporting obligations. The IFR adopts and incorporates by reference the requirements and recommendations contained in American Petroleum Institute ("API") Recommended Practice ("RP") 1170 and 1171. Existing underground natural gas storage facilities must meet the appropriate requirements and recommendations of API 1170 and 1171 by January 18, 2018. While we believe that our facilities are currently in substantial conformance with API 1170 and 1171, a review is underway to ensure consistency.

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

Operational Hazards and Insurance

Pipelines, terminals, trucks or other facilities or equipment may experience damage as a result of an accident, natural disaster, terrorist attack, cyber event or other event. 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 and varying levels of insurance coverage that we consider adequate under the circumstances to cover our operations and properties, and we self-insure certain risks, including gradual pollution and named windstorm. With respect to our insurance, our policies are subject to deductibles and retention levels that we consider reasonable and not excessive. However, such insurance does not cover every potential risk that might occur, associated with operating pipelines, terminals and other facilities and equipment, including the potential loss of significant revenues and cash flows.

Since the terrorist attacks of September 11, 2001, 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 that we maintain adequate insurance coverage, although insurance will not cover many types of interruptions that might occur, will not cover amounts up to applicable deductibles and will not cover all risks associated with certain of our assets and operations. Additionally we self-insure certain risks including, gradual pollution and named windstorm. With respect to our insurance coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable. As a result, we may elect to self-insure or utilize higher deductibles in certain other insurance programs. In addition, although we believe that we have established adequate reserves and liquidity to the extent such risks are not insured, costs incurred in excess of these reserves may be higher or we may not receive insurance proceeds in a timely manner, and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

Title to Properties and Rights-of-Way

Our real property holdings generally consist of: (i) parcels of land that we own in fee, (ii) surface leases and 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. In all material respects, 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. Except for challenges that we do not regard as material relative to our overall operations, 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.

Employees and Labor Relations

Through GP LLC or its affiliates, we employed approximately 5,100 employees at December 31, 2016. None of these employees were subject to a collective bargaining agreement, except for eight employees covered by an agreement scheduled for renegotiation in September 2019; 61 employees covered by a separate agreement scheduled for renegotiation in January 2019; and 23 employees covered by a separate agreement scheduled for renegotiation in January 2019. Also, a first collective agreement is being negotiated for 61 employees who recently unionized in Canada. We consider employee relations to be good.

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, 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 or a court 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 our Class A shares will be treated as distributions on corporate stock for U.S. federal income tax purposes. No Schedule K-1s will be issued with respect to our Class A shares. Instead holders of Class A shares will receive a Form 1099 from us with respect to distributions received on our 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 that, for U.S. federal income tax purposes, is:

- an individual who is a citizen or resident of the United States;
- a corporation (or other entity treated as a corporation for U.S. federal income tax purposes) created or organized in or under the laws of the United States, any state thereof or the District of Columbia;
- an estate the income of which is subject to U.S. federal income tax regardless of its source; or
- a trust (i) the administration of which is subjected to the primary supervision of a U.S. court and which has one or more United States persons who have the authority to control all substantial decisions of the trust or (ii) which has made a valid election under applicable U.S. Treasury regulations 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 from the sale or exchange of such Class A shares. See "-Gain on Disposition of Class A Shares" below. Non-corporate holders that receive distributions on our Class A shares that are treated as dividends for U.S. federal income tax purposes generally will be subject to U.S. federal income tax at a reduced rate (currently at a maximum tax rate of 20%) 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 acquisition of AAP Class A units in connection with our IPO and in connection with exchanges since the IPO by the Legacy Owners and their permitted transferees of their AAP Class A units and Class B shares for Class A shares have 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 AAP Class A units and Class B shares for our 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, 2017 through 2019, 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 with respect to such distribution.

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 U.S. federal income tax at a reduced rate (currently at a maximum 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

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. Subject to the withholding requirements under FATCA (as defined below) and with respect to effectively connected dividends, each of which is discussed below, any distribution treated as a dividend paid to a non-U.S. holder on our Class A shares generally 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 a United States real property holding corporation (a "USRPHC") 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 15% (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 applicable withholding agent with an IRS W-8BEN or IRS Form W-8BEN-E (or other applicable or successor 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 income 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 United States persons (as defined under the Code). Such effectively connected dividends will not be subject to U.S. withholding tax if the non-U.S. holder satisfies certain certification requirements by providing the applicable withholding agent a properly executed IRS Form W-8ECI (or successor form) certifying eligibility for exemption. If a non-U.S. holder is a non-U.S. corporation, it may also be subject to a "branch profits tax" (at a 30% rate or such lower rate as may be specified by an applicable income tax treaty) on its effectively connected earnings and profits (as adjusted for certain items), which will include effectively connected dividends.

Gain on Disposition of Class A Shares

Subject to the discussion below under "-Additional Withholding Requirements under FATCA," 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 income 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 United States real property interest by reason of our status as a 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 income tax treaty) on the amount of such gain, which generally may be offset by U.S. source capital losses.

A non-U.S. holder whose gain is described in the second bullet point above or, subject to the exceptions described in the next paragraph, the third bullet point above, generally will be taxed on a net income basis at the rates and in the manner generally applicable to United States persons (as defined under the Code) unless an applicable income tax treaty provides otherwise. If the non-U.S. holder is a corporation whose gain is described in the second bullet point above, then such gain would also be included in its effectively connected earnings and profits (as adjusted for certain items), which may be subject to a branch profits tax (at a 30% or such lower rate as may be specified by an applicable income tax treaty).

Generally, a corporation is a USRPHC if the fair market value of its United States 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 continue to be regularly traded on an established securities market, only a non-U.S. holder that actually or constructively owns, or owned at any time during the shorter of the five-year period ending on the date of the disposition or the non-U.S. holder's holding period for the Class A shares, more than 5% of our Class A shares will be taxable on gain recognized on the disposition of our Class A shares as a result of our status as a USRPHC. If our Class A shares were not considered to be regularly traded on an established securities market, such non-U.S. holder (regardless of the percentage of our

Class A shares owned) would be subject to U.S. federal income tax on a taxable disposition of our Class A shares (as described in the preceding paragraph), and a withholding tax would apply to the gross proceeds from such disposition at the applicable withholding rate (currently at a rate of 15%).

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.

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, IRS Form W-8BEN-E or other 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 United States 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, IRS Form W-8BEN-E or other appropriate version of IRS Form W-8 and certain other conditions are met. 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 non-U.S. office of a broker. However, unless such broker has documentary evidence in its records that the holder is not a United States person 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 backup withholding results in an overpayment of taxes, a refund may be obtained, provided that certain required information is timely furnished to the IRS.

Additional Withholding Requirements under FATCA

Sections 1471 through 1474 of the Code, and the Treasury regulations and administrative guidance issued thereunder ("FATCA"), impose a 30% withholding tax on any dividends paid on our Class A shares and on the gross proceeds from a disposition of our Class A shares (if such disposition occurs after December 31, 2018), in each case if paid to a "foreign financial institution" or a "non-financial foreign entity" (each as defined in the Code) (including, in some cases, when such foreign financial institution or non-financial foreign 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 non-U.S. 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 United States owners" (as defined in the Code) or provides the applicable withholding agent with a certification identifying each direct and indirect substantial United States owner of the entity (in either case, generally on an IRS Form W-8BEN-E), or (iii) the foreign financial institution or non-financial foreign entity otherwise qualifies for an exemption from these rules and provides appropriate documentation (such as an IRS Form W-8BEN-E). Foreign financial institutions located in jurisdictions that have an intergovernmental agreement with the United States governing these rules may be subject to different 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.

Available Information

We make available, free of charge on our Internet website at ir.pagp.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"). The public may read and copy any materials filed by PAGP with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Room 1580, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site that

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contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at http://www.sec.gov.

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:

- our payment of any income taxes;
- restrictions on distributions contained in PAA's credit facilities and any future debt agreements entered into by AAP, PAA or us; 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 distributions AAP is entitled to receive may fluctuate, which may reduce cash distributions to our Class A shareholders.

At December 31, 2016, we directly and indirectly owned an approximate 42% limited partner interest in AAP, which owned 241,672,409 PAA common units. All of the cash flow we receive from AAP is derived from its ownership of these PAA common units. Because distributions on PAA common units are dependent on the amount of cash PAA generates, distributions may fluctuate based on PAA's performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of PAA. 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, PAA's cash distributions might be made during periods when PAA records losses and might not be made during periods when PAA record profits.

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

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distributions we receive from AAP, which are derived from AAP's 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 that AAP owns. 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.

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

PAA's credit facilities contain various operating and financial restrictions and covenants. PAA's ability to comply with these restrictions and covenants may be affected by events beyond their control, including prevailing economic, financial and industry conditions. If PAA is unable to comply with these restrictions and covenants, any indebtedness under these credit facilities may become immediately due and payable and PAA's lenders' commitment to make further loans under these credit facilities may terminate. PAA might not have, or be able to obtain, sufficient funds to make these accelerated payments.

For more information regarding 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."

Our shareholders do not elect or have the power to remove our general partner. 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. 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, 2016, the Legacy Owners owned approximately 58% of our outstanding Class A and Class B 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, 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 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 will receive cash in exchange for its general partner interest. 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 purchase the general partner interest for its fair market value. If PAA GP's interests are not purchased in accordance with the foregoing theory, they 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.

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, except that such shares constituting up to 19.9% of the total shares outstanding may be voted in the election of directors. 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.

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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, 2016, through their ownership of Class B shares, the Legacy Owners held approximately 58% 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.

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

A deferred tax asset of approximately $1.9 billion, that is being amortized, was recorded on our books as a result of certain of the transactions that took place in connection with our 2013 initial public offering, our November 2014 secondary offering and 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 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.

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.

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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:

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 Class C shares and 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, 2016, the Legacy Owners owned approximately 58% of our outstanding Class A and Class B shares and approximately 58% 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.

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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, 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.

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, 2016, the Legacy Owners owned approximately 58% of the Class A shares and Class B shares on a combined basis.

Risks Related to PAA's Business

PAA's profitability depends on the volume of crude oil, 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 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 gas reservoirs, a decrease in exploration and development activities, supply disruptions, economic conditions or otherwise, could result in a decline in the volume of crude oil, natural gas or NGL handled by PAA's facilities.

During the latter half of 2014 and continuing into 2016, benchmark crude oil prices declined significantly; as a result, many of the companies that produce oil and gas significantly reduced capital expenditures. Such reduced expenditure levels, coupled with high decline rates for many horizontal wells in the shale resource plays, led to production declines in many areas in the Lower 48 United States (excluding Gulf of Mexico production). Other factors that could adversely impact production include reduced capital market access, increased capital raising costs for producers or adverse governmental or regulatory action. In turn, such developments could lead to reduced throughput on PAA's pipelines and at PAA's other facilities, which, depending on the level of production declines, could have a material adverse effect on PAA's business.

Also, except with respect to some of our recently constructed pipeline assets, third-party shippers generally do not have long-term contractual commitments to ship crude oil on 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.

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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 reduced drilling activity by producers, natural declines in crude oil production from depleting wells or volumes lost to competitors. If production declines, competitors with under-utilized assets could impair PAA's ability to secure additional supplies of crude oil.

PAA may not be able to compete effectively in its transportation, facilities and supply and logistics activities, and PAA's business is subject to various risks associated with the general capacity overbuild of midstream energy infrastructure in some of 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 participants in a wide variety of contexts, including new entrants and existing participants and in connection with day-to-day business, expansion capital 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) stems from the rapid development of new midstream energy infrastructure capacity that was 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 presented opportunities for PAA, many of these areas have become overbuilt, resulting in an excess of midstream energy infrastructure capacity. In addition, as an established participant 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. Current expectations for oil and gas development in many of the areas where PAA operates are not as robust as they were during the last few years. This adversely impacts both PAA's existing assets and growth projects in such areas. PAA also faces competition for incremental volumes from shippers on third party pipelines who overcommitted relative to their actual production or committed supplies and are now purchasing barrels on the open market and shipping them on such third party pipelines in order to satisfy their minimum commitment levels. This puts downward pressure on PAA's throughput and margins and, together with other adverse competitive effects, 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, private equity backed entities, independent gatherers, 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, 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.

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

Supply and 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. The supply of crude oil depends on a variety of global political and economic factors, including the reliance of foreign governments on petroleum revenues. Excess global supply of crude oil may negatively impact PAA's operating results by decreasing the price of crude oil and making production and transportation less profitable in areas PAA services.

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 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) can have a positive impact on lease gathering margins because in certain circumstances crude oil gatherers can capture a premium for prompt deliveries; however, in this environment there is little incentive to store crude oil as current prices are above future delivery prices. In either case, margins can be improved when prices are volatile. The periods between these two market structures are referred to as transition periods. If the market is in a backwardated to transitional structure, 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 agreements, these transition periods may have either an adverse or beneficial effect on its aggregate segment results. 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 (including eco-terrorist attacks), process safety failure or other event, including pipeline or facility accidents and 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 or other natural events, including hurricanes, tornadoes, storms, floods, earthquakes, shifting soil and/or landslides. The location of some 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. PAA's facilities and operations are also vulnerable to accidents caused by process safety failures, equipment failures or human error. In addition, since the September 11, 2001 terrorist attacks, the U.S. government has issued warnings that energy assets, specifically the nation's pipeline infrastructure, may be future targets of terrorist organizations. Terrorists may target PAA's physical facilities and hackers may attack its electronic and computer systems.

If one or more of PAA's pipelines or 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.

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

PAA may face opposition to the operation of its pipelines and facilities from various groups.

PAA may face opposition to the operation of its pipelines and facilities from environmental groups, landowners, tribal groups, local groups and other advocates. Such opposition could take many forms, including organized protests, attempts to block or sabotage PAA's operations, intervention in regulatory or administrative proceedings involving PAA's assets, or lawsuits or other actions designed to prevent, disrupt or delay the operation of PAA's assets and business. For example, repairing PAA's pipelines often involves securing consent from individual landowners to access their property; one or more landowners may resist PAA's efforts to make needed repairs, which could lead to an interruption in the operation of the affected pipeline or facility for a period of time that is significantly longer than would have otherwise been the case. In addition, acts of sabotage or eco-terrorism could cause significant damage or injury to people, property or the environment or lead to extended interruptions of PAA's operations. Any such event that interrupts the revenues generated by PAA's operations, or which causes PAA to make significant expenditures not covered by insurance, could reduce PAA's cash available for paying distributions to its partners and, accordingly, adversely affect PAA's financial condition and the market price of PAA's securities.

Cybersecurity breaches and other disruptions could compromise PAA's information and operations, and expose it to liability, which would cause its business and reputation to suffer.

In the ordinary course of our business, PAA collects and store sensitive data, including intellectual property, its proprietary business information and information regarding its customers, suppliers and business partners, and personally identifiable information of its employees, in its data centers and on its networks. The secure processing, maintenance and transmission of this information is critical to PAA's operations and business strategy. Despite PAA's security measures, its information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise PAA's networks and the information stored there could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties for divulging shipper information, disruption of PAA's operations, damage to its reputation, and loss of confidence in its services, which could adversely affect its business.

PAA's information technology infrastructure is critical to the efficient operation of its business and essential to its ability to perform day-today operations. Breaches in PAA's information technology infrastructure or physical facilities, or other disruptions, could result in damage to its assets, safety incidents, damage to the environment, potential liability or the loss of contracts, and have a material adverse effect on its operations, financial position and results of operations.

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 expansion capital 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, increases in key benchmark interest rates and/or credit spreads, the adoption of new or amended banking or capital market laws or regulations, the re-pricing of market risks and volatility in capital and financial markets.

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In addition, PAA's ability to achieve and maintain its target credit profile is in part dependent on its ability to consummate previously announced divestiture transactions. The closing of such transactions is not entirely within PAA's control and depends in part on the satisfaction of closing conditions that require action by governmental authorities or others. To the extent PAA is unable to consummate such transactions, PAA may be forced to incur additional indebtedness or issue more equity than it would have otherwise preferred, which could make it harder for PAA to achieve its target credit profile.

Due to these factors, PAA cannot be certain that funding for its capital needs will be available from bank credit arrangements, capital markets or other sources 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 borrowing costs, 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, Moody's Investors Service and Fitch Ratings Inc.; however, in late January 2017, Moody's Investors Service placed such rating under review for downgrade. A downgrade below PAA's current ratings levels by any 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 receives 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 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. Loss of PAA's investment grade credit rating could also adversely impact its cash flows, its ability to make distributions at its current levels and the value of its outstanding equity and debt securities.

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, may be obtained with conditions that materially alter the expected return associated with the underlying projects or may be granted and then subsequently withdrawn;
- PAA may face opposition to its planned growth projects from environmental groups, landowners, local groups and other advocates, including lawsuits or other actions designed to disrupt or delay PAA's planned projects;
- PAA may not be able to obtain, or PAA may be significantly delayed in obtaining, all of the rights of way or other real property interests it needs 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;
- 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 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, including increased costs associated with any requirements to source certain supplies or materials from U.S. suppliers or manufacturers, 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

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- 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 or could be delayed. In turn, this could negatively impact PAA's cash flow and its ability to make or increase cash distributions to its partners.

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 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.

Acquisitions involve risks that may adversely affect PAA's 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 either not indemnified, or the indemnity is not from a credit-worthy party, including liabilities arising from the operation of the acquired businesses or assets prior to 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 is exposed to the credit risk of its customers and other counterparties it transacts within the ordinary course of its business activities.

Risks of nonpayment and nonperformance by customers are a significant consideration in PAA's business and are of increased concern in the current low commodity price environment. 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.

PAA has a number of minimum volume commitment contracts that support pipelines in its Transportation segment. In addition, certain of the pipelines in which PAA owns a joint venture interest have minimum volume commitment contracts. Pursuant to such contracts, shippers are obligated to pay for a minimum volume of transportation service regardless of whether such volume is actually shipped (typically referred to as a deficiency payment), subject to the receipt of credits that typically expire if not used by a certain date. While such contracts provide greater revenue certainty, if the applicable shipper fails to transport the minimum required volume and is required to make a deficiency payment, under applicable accounting rules, the revenue associated with such deficiency payment may not be recognized until the applicable transportation credit has expired or has been used. Deferred revenue associated with non-performance by shippers under minimum volume contracts could be significant and could adversely affect PAA's profitability and earnings.

In addition, 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.

Further, to the extent one or more of PAA's major customers experiences financial distress or commences bankruptcy proceedings, contracts with such customers (including contracts that are supported by acreage dedications) may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. Any such renegotiation or rejection could have an adverse effect on PAA's revenue and cash flows and its ability to make cash distributions to its unitholders.

PAA have also undertaken numerous projects that require cooperation with and performance by joint venture co-owners. Nonperformance by these parties could result in increased costs or delays that could decrease PAA's returns on these joint venture projects.

PAA also relies to a significant degree on the banks that lend to it under its revolving credit facility for financial liquidity, and any failure of those banks to perform on their obligations to PAA could significantly impair its liquidity. Furthermore, nonpayment by the counterparties to PAA's interest rate, commodity and/or foreign currency derivatives could expose it to additional interest rate, commodity price and/or foreign currency risk.

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 crude oil, refined products and NGL, up to predefined limits and authorizations. Although this activity is monitored independently by PAA's risk management function, it exposes PAA to commodity price risks within these limits.

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 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 expansion capital 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 it believes go beyond regulatory mandates. See Items 1 and 2 "Business and Properties—Regulation."

For 2017 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 continued 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 enhance 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 "Environmental — General" in Note 17 to our Consolidated Financial Statements. In addition, despite PAA's pipeline and facility integrity management efforts, it can provide no assurance that its pipelines and facilities will not experience leaks or releases or that PAA will be able to fully comply with all of the federal, state and local laws and regulations applicable to the operation of PAA's pipelines or facilities; any such leaks or releases could be material and could have a significant adverse impact on PAA’s reputation, financial position, cash flows and ability to pay or increase distributions to its unitholders.

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.

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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.

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 crude oil, natural gas and NGL, and hedging activities, expose it to potential regulatory risks.

The FTC, the FERC and the CFTC hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to PAA's physical sales of oil, natural gas or NGL, and any related 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 CFTC could result in the imposition of civil and criminal penalties. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on 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 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 for, and expects to continue to qualify for, the end-user exception from the mandatory clearing requirements for

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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.

Certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although PAA qualifies for the end-user exception from margin requirements for swaps entered into to hedge commercial risks, if any of PAA's swaps do not qualify for the commercial end-user exception, a requirement to post additional cash margin or collateral could reduce PAA's ability to execute hedges necessary to reduce commodity price exposures and protect cash flows. 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.

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. In addition, implementation of the Dodd Frank Act and related rules and regulations could reduce the overall liquidity and depth of the markets for financial and other derivatives 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 lower 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. 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. We do not perform hydraulic fracturing, but many of the producers using our pipelines do. Hydraulic fracturing has been subject to increased scrutiny due to public concerns that it could result in contamination of drinking water supplies, and there have been a variety of legislative and regulatory proposals to prohibit, restrict, or more closely regulate various forms of hydraulic fracturing. Any legislation or regulatory initiatives that curtail hydraulic fracturing could reduce the production of crude oil and natural gas in the United States or Canada, and could thereby reduce demand for PAA’s transportation, terminalling and storage services as well as its supply and logistics services.

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, as well as the fact that PAA has experienced several incidents over the last 3 to 5 years, premiums and deductibles for certain insurance policies have 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, 2016, the face value of PAA's consolidated debt outstanding was approximately $11.9 billion, consisting of approximately $10.2 billion face value of long-term debt (including senior notes and long-term commercial paper borrowings) and approximately $1.7 billion of short-term borrowings. As of December 31, 2016, PAA had approximately $2.4 billion of liquidity available, including cash and cash equivalents and available borrowing capacity under its senior unsecured revolving credit facility, its senior secured hedged inventory facility and its senior unsecured 364-day credit facility, subject to continued covenant compliance. Lower Adjusted EBITDA could increase PAA's leverage ratios and effectively reduce its ability to incur additional indebtedness.

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—PAA Credit Agreements, Commercial Paper Program 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.

Increases in interest rates could adversely affect PAA's business and the trading price of its units.

As of December 31, 2016, the face value of PAA's consolidated debt was approximately $11.9 billion, of which approximately $10.3 billion was at fixed interest rates and approximately $1.6 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. Further, the trading price of PAA's common units may be sensitive to changes in interest rates and any rise in interest rates could adversely impact such trading price.

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

Because PAA is a U.S. dollar reporting company and also conducts 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. For example, as the U.S. dollar appreciates against the Canadian dollar, the U.S. dollar value of PAA's Canadian dollar denominated earnings is reduced for U.S. reporting purposes.

An impairment of long-term assets could reduce PAA's earnings.

At December 31, 2016, PAA had approximately $13.9 billion of net property and equipment, $2.3 billion of goodwill, $2.3 billion of investments accounted for under the equity method of accounting and $242 million of net intangible assets capitalized on its balance sheet. GAAP requires an assessment for impairment on an annual basis or in certain circumstances, including when there is an indication that the carrying value of property and equipment may not be recoverable or a determination that it is more likely than not that a reporting unit's carrying value is in excess of the reporting unit's fair value. If PAA was to determine that any of its property and equipment, goodwill, intangibles or equity method investments was impaired, it could be required to take an immediate charge to earnings, which could adversely impact its operating results, with a corresponding reduction of partners' capital and increase in balance sheet leverage as measured by debt-to-total capitalization. During the year ended December 31, 2016, PAA recognized impairment losses of approximately $80 million. See Note 5 to our Consolidated Financial Statements for additional information regarding impairments.

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

PAA's supply and logistics operations include purchasing crude oil that is carried on railcars, tankers or barges. Such cargos are at risk of being damaged or lost because of events such as derailment, marine disaster, inclement weather, mechanical failures, grounding or collision, fire, explosion, environmental accidents, piracy, terrorism and political instability. Such occurrences could result in death or injury to persons, loss of property or environmental damage, delays in the delivery of cargo, loss of revenues, termination of contracts, governmental fines, penalties or restrictions on conducting business, higher insurance rates and damage to 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 PAA's Facilities segment revenue and cash flow.

Non-utilization of certain assets, such as PAA's leased railcars, could significantly reduce its profitability due to 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 railcars, 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 a significant number of its railcars, 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 railcars. In addition, during the period of time that PAA is not utilizing such railcars, it will incur incremental costs associated with the cost of storing such railcars and will continue to incur costs for maintenance and upkeep. Non-utilization of its leased assets in connection with PAA's business could have a significant negative impact on PAA's profitability and cash flows.

Many of PAA's assets have been in service for many years and require significant expenditures to maintain them. As a result, its maintenance or repair costs may increase in the future.

PAA's pipelines, terminals and storage assets are generally long-lived assets, and many of them have been in service for many years. The age and condition of its assets could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect PAA's results of operations, financial position or cash flows, as well as its ability to make cash distributions to our unitholders.

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;
- 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 opportunistic leaching activities at its facilities in connection with the expansion of existing salt 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 be substantial and will reduce PAA's cash available for distribution to its partners.

Prior to making any distribution on its common units, PAA will reimburse PAA GP and its affiliates, including officers and directors of its general partner, for all expenses incurred on PAA's behalf. In addition, PAA is required to pay all direct and indirect expenses of the Plains Entities, other than income taxes of any of the PAGP Entities. The reimbursement of expenses and the payment of fees and expenses could adversely affect PAA's ability to make distributions. 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 common units are dependent on the amount of cash it generates, distributions may fluctuate based on PAA's performance, which will result in fluctuations in the amount of distributions ultimately received by

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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.

PAA's preferred units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of PAA's common units.

PAA's Series A Preferred Units (the "PAA preferred units"), issued in January 2016, rank senior to all of PAA's other classes or series of equity securities with respect to distribution rights and rights upon liquidation. These preferences could adversely affect the market price for PAA's common units, or could make it more difficult for PAA to sell common units in the future.

In addition, distributions on the PAA preferred units accrue and are cumulative, at the rate of 8% per annum on the original issue price and are convertible into PAA common units by the holders of such units or by PAA in certain circumstances. PAA's obligation to pay distributions on its preferred units, or on the common units issued following the conversion of such preferred units, could impact its liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions, and other general partnership purposes. PAA's obligations to the holders of preferred units could also limit its ability to obtain additional financing or increase our borrowing costs, which could have an adverse effect on PAA's financial condition.

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 additional entity-level taxation by individual states. If the Internal Revenue Service ("IRS") were to treat PAA as a corporation for federal income tax purposes or if 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, 2016, we owned an approximate 42% limited partner interest in AAP, which directly owned a 33% limited partner interest in PAA through its ownership of 241,672,409 PAA common units. 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"). The IRS issued final regulations on January 24, 2017, that are effective January 19, 2017, that define the activities that generate qualifying income from exploration, development, mining or production, processing, refining, transportation, and marketing of minerals or natural resources within the meaning of Section 7704. These regulations are intended to provide regulatory guidance on whether income from activities with respect to minerals or natural resources is qualifying income.

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 additional entity-level taxation. In addition, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, 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.

Legislative changes to the IRS audit rules, starting with partnership tax years beginning after 2017, will allow the IRS to assess and collect tax on audit adjustments at the partnership level as opposed to the partner level unless the partnership makes an election or exercises certain alternatives. Changes were also made to limit partner representation in the event of an audit.

The Bipartisan Budget Act of 2015 (H.R. 1315) ("Act"), effective for partnership tax years beginning after December 31, 2017, repeals the partnership audit rules of the Tax Equity and Fiscal Responsibility Act of 1982 ("TEFRA") and replaces the TEFRA provisions with new provisions that allow for the IRS to assess and collect taxes associated with audit adjustments, referred to as an "imputed underpayment", at the partnership entity level rather than the partner level in the year the partnership adjustment is made, the "adjustment year", as opposed to the year the adjustment relates, the "reviewed year". The imputed underpayment is calculated using the highest tax rate in effect for the reviewed year. The implications of an imputed underpayment are that current partners could be liable for a liability of former partners. If an audit adjustment did result in a material imputed underpayment the partnership would need to determine whether to pay the imputed underpayment or to avail itself of one of three alternative provisions under the Act that can shift the partnership level tax liability back onto the prior tax year partners. The first alternative, an opt-out election, is not available to PAA as a publicly traded partnership because PAA does not meet the criteria of 100 or fewer partners. The second alternative would require the partnership to submit audit adjustment information to the affected partners and to the IRS as well as ensure amended return compliance by our partners within 270 days after receipt of the proposed audit adjustment. From an administrative standpoint, considering the number of PAA's partners, as a publicly traded partnership, the second alternative is not a viable option to PAA. The third alternative is an election by PAA that would require the partnership, not later than 45 days after the date of the notice of final partnership adjustment, to furnish to each affected partner and to the IRS a statement of each partner's share of any adjustment to income, gain, loss, deduction, or credit. Under this alternative, reviewed year partners calculate their share of additional tax due and pay the additional amount with their respective current year individual tax returns. An election under this provision, however, because the reviewed year is older increases the applicable imputed underpayment interest rate by two percentage points. If PAA was required to pay taxes, penalties and interest as the result of audit adjustments, cash available for distribution to their unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited taxable year.

Also for partnership tax years beginning after 2017, the Act eliminated rights that certain individual partners might previously have had in the audit process by now restricting it to a single “partnership representative”

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. For example, the Obama administration’s budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. From time to time, members of Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Similar proposals could 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.

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

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 did not have any earnings and profits in 2016 and 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, 2017 through 2019. 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 tax deductions associated with our initial and subsequent acquisitions of interests in AAP (as a result of the exercise by Legacy Owners of their exchange rights) will offset all of our current taxable income for an extended period of time, and thus result in our distributions not constituting taxable dividends for an extended period of time, is based on current law with respect to the amortization of basis adjustments associated with our acquisition of interests in AAP. 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

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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.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

The information required by this item is included in Note 17 to our Consolidated Financial Statements, and is incorporated herein by reference thereto.

Item 4. Mine Safety Disclosures

Not applicable.

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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." In connection with the closing of the Simplification Transactions, as discussed further below, we completed a reverse split of our Class A and Class B shares, in each case, at a ratio of approximately 1-for-2.663. No fractional shares were issued. Accordingly, our Class A shares began trading on a split-adjusted basis on the NYSE at the opening of trading on November 16, 2016. The effect of this reverse split has been retroactively applied to all share and per share amounts presented in this Form 10-K. See Note 11 to our Consolidated Financial Statements for further discussion of the Simplification Transactions.

As of February 10, 2017, the closing market price for our Class A shares was $31.79 per share and there were approximately 38,000 record holders and beneficial owners (held in street name). As of February 10, 2017, there were 103,269,257 Class A shares outstanding.

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

	Class A Share Price Range		Cash Distributions [1]
	High	Low	
2016			
4th Quarter	$36.59	$28.84	$ 0.55
3rd Quarter	$35.10	$25.59	$ 0.55
2nd Quarter	$30.70	$20.98	$ 0.62
1st Quarter	$25.80	$12.57	$ 0.62
2015			
4th Quarter	$51.90	$19.12	$ 0.62
3rd Quarter	$70.94	$43.35	$ 0.62
2nd Quarter	$79.54	$68.73	$ 0.60
1st Quarter	$77.12	$63.94	$ 0.59

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

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

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

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

Simplification Transactions

On November 15, 2016, the Plains Entities closed a series of transactions and executed several organizational and ancillary documents (the "Simplification Transactions") intended to simplify our capital structure, better align the interests of our stakeholders and improve our overall credit profile. The Simplification Transactions included, among other things: the permanent elimination of PAA's incentive distribution rights ("IDRs") and the economic rights associated with its 2% general partner interest in exchange for the issuance by PAA to AAP of 245.5 million PAA common units (including approximately 0.8 million units to be issued in the future) and the assumption by PAA of all of AAP's outstanding debt ($642 million); the implementation of a unified governance structure pursuant to which the board of directors of PAA's general partner was eliminated and an expanded board of directors of our general partner assumed oversight responsibility over both us and PAA; and provision for annual shareholder elections beginning in 2018 with certain directors with expiring terms in 2018, and the participation of PAA's common unitholders and Series A preferred unitholders in such elections through its ownership of our newly issued Class C shares, which provide PAA, as the sole holder, the right to vote in elections of eligible directors together with the holders of our Class A and Class B shares. In addition, we entered into an Omnibus Agreement with AAP and PAA to promote economic alignment between our Class A shareholders and PAA's common unitholders by, among other measures, maintaining a one-to-one relationship between the number of our outstanding Class A shares and the number of PAA common units indirectly owned by us through AAP.

See Note 1 to our Consolidated Financial Statements for further discussion of the Simplification Transactions.

Cash Distribution Policy

Our partnership agreement requires that, within 55 days following 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; or
- provide for the proper conduct of our business;

As of December 31, 2016, our only cash-generating assets consisted of an indirect limited partnership interest in PAA through our direct and indirect approximate 42% limited partner interest in AAP. AAP currently receives all of its cash flows from its ownership of PAA common units. 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 such common units. 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 PAA's debt, PAA is 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—PAA Credit Agreements, Commercial Paper Program and Indentures."

Recent Sales of Unregistered Securities

In connection with our IPO and related transactions, the former owners of Plains All American GP LLC (the "Legacy Owners") acquired the following interests (collectively, the "Stapled Interests"): (i) Class A units of AAP ("AAP units") representing an economic limited partner interest in AAP; (ii) general partner units representing a non-economic membership interest in our general partner; and (iii) Class B shares representing a non-economic limited partner interest in us. The Legacy Owners and any permitted transferees of their Stapled Interests have the right to exchange (the "Exchange Right") all or a portion of such Stapled Interests for an equivalent number of Class A shares. In connection with the exercise of the Exchange Right, the Stapled Interests are transferred to us and the applicable Class B shares are canceled. Although we issue one Class A share for each Stapled Interest that is exchanged, we also receive one AAP unit and one general partner unit. As a result, the exercise by Legacy Owners of the Exchange Right is not dilutive. During the three months ended December 31, 2016, certain Legacy Owners or their permitted transferees exercised the Exchange Right, which resulted in the issuance of 434,602 Class A shares. The issuance of Class A shares in connection with the exercise of the Exchange Rights was exempt from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(2) thereof.

Issuer Purchases of Equity Securities

We did not repurchase any of our Class A shares during the fourth quarter of 2016, and we do not have any announced or existing plans to repurchase any of our Class A shares.

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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 financial information below was derived from the audited financial statements of PAGP (and GP LLC as discussed above) as of December 31, 2016, 2015, 2014, 2013 and 2012 and for the years then ended.

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

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(in millions, except per unit data)				
Statement of operations data:					
Total revenues	$20,182	$23,152	$43,464	$42,249	$37,797
Operating income	$990	$1,258	$1,791	$1,734	$1,433
Net income	$660	$809	$1,328	$1,374	$1,118
Net income attributable to PAGP	$94	$118	$70	$15	$3
Per share data:					
Basic net income per Class A share [(1)]	$0.94	$1.41	$1.28	$0.25	N/A
Diluted net income per Class A share [(1)]	$0.94	$1.41	$1.25	$0.25	N/A
Declared distributions per Class A share [(2)]	$2.40	$2.35	$1.78	N/A	N/A
Balance sheet data (at end of period):					
Property and equipment, net	$13,890	$13,493	$12,292	$10,841	$9,664
Total assets	$26,103	$24,142	$23,923	$21,411	$19,219
Long-term debt	$10,124	$10,932	$9,238	$7,188	$6,480
Total debt	$11,839	$11,931	$10,525	$8,301	$7,566
Partners' capital / Members' equity:					
Partners' capital / Members' equity (excluding Noncontrolling interests)	$1,737	$1,762	$1,657	$1,035	$—
Noncontrolling interests	$8,970	$7,472	$7,724	$7,244	$6,968
Total Partners' capital / Members' equity	$10,707	$9,234	$9,381	$8,279	$6,968
Other data:					
Net cash provided by operating activities	$711	$1,333	$1,988	$1,948	$1,232
Net cash used in investing activities	$(1,273)	$(2,530)	$(3,296)	$(1,653)	$(3,392)
Net cash provided by/(used in) financing activities	$578	$827	$1,672	$(274)	$2,159
Capital expenditures:					
Acquisition capital	$289	$105	$1,099	$19	$2,286
Expansion capital	$1,405	$2,170	$2,026	$1,622	$1,185
Maintenance capital	$186	$220	$224	$176	$170

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	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(in millions, except per unit data)				
Volumes [3] [4]					
Transportation segment (average daily volumes in thousands of barrels per day):					
Tariff activities	4,523	4,340	3,952	3,595	3,373
Trucking	114	113	127	117	106
Transportation segment total volumes	4,637	4,453	4,079	3,712	3,479
Facilities segment:					
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	107	100	95	94	90
Rail load / unload volumes (average volumes in thousands of barrels per day)	83	210	231	221	—
Natural gas storage (average monthly working capacity in billions of cubic feet)	97	97	97	96	84
NGL fractionation (average volumes in thousands of barrels per day)	115	103	96	96	79
Facilities segment total volumes (average monthly volumes in millions of barrels)	129	126	121	120	106
Supply and Logistics segment (average daily volumes in thousands of barrels per day):					
Crude oil lease gathering purchases	894	943	949	859	818
NGL sales	259	223	208	215	182
Waterborne cargos	7	2	—	4	3
Supply and Logistics segment total volumes	1,160	1,168	1,157	1,078	1,003

(1) Basic and diluted net income per Class A share for 2013 were calculated based on net income attributable to PAGP for the period following the closing of our initial public offering on October 21, 2013 and basic weighted average Class A shares outstanding weighted for the same period.

(2) Represents cash distributions declared and paid during the year presented. See Note 11 to our Consolidated Financial Statements for further discussion regarding our distributions.

(3) Average volumes are calculated as the total volumes (attributable to our interest) for the year divided by the number of days or months in the year.

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

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

Introduction

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

Our discussion and analysis includes the following:

- Executive Summary
- Acquisitions and Capital Projects
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements
- Results of Operations
- Market Overview and Outlook
- Liquidity and Capital Resources

Executive Summary

Company Overview

We are a Delaware limited partnership formed on July 17, 2013 that has elected to be taxes as a corporation for United States federal income tax purposes. As of December 31, 2016, our sole assets consisted of (i) a 100% managing member interest in Plains All American GP LLC ("GP LLC") that has also elected to be taxed as a corporation for United States federal income tax purposes and (ii) an approximate 42% limited partner interest in AAP through our direct ownership of 100,198,807 AAP units and indirect ownership of 1,007,719 AAP units through GP LLC. GP LLC is a Delaware limited liability company that also holds the non-economic general partner interest in AAP. AAP is a Delaware limited partnership that, as of December 31, 2016, directly owns an approximate 33% limited partner interest in PAA represented by 241.7 million PAA common units. AAP is the sole member of PAA GP LLC ("PAA GP"), a Delaware limited liability company that directly holds the non-economic general partner interest in PAA.

PAA owns and operates midstream energy infrastructure and provides logistics services for crude oil, NGL, natural gas and refined products. 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.

Overview of Operating Results, Capital Investments and Other Significant Activities

The transitioning crude oil market over the last two years created a challenging environment for the overall midstream industry. See the "—Market Overview and Outlook" section below for further discussion. We recognized net income of $660 million in 2016 as compared to net income of $809 million recognized in 2015. This year-over-year decrease was impacted by:

- Lower operating results, primarily due to less favorable crude oil and NGL market conditions, increased competition and the impact of mark-to-market losses on certain derivative instruments, partially offset by (i) contributions from our recently completed acquisition and capital expansion projects and (ii) lower field operating costs, largely due to lower trucking costs associated with our supply and logistics activities and the absence of costs related to the Line 901 incident, which occurred in May 2015;

- Higher depreciation and amortization expense primarily resulting from (i) our recently completed capital expansion projects, (ii) impairment losses related to certain of our rail and other terminal assets and (iii) assets taken out of service and the discontinuation of certain capital projects, all partially offset by net gains related to non-core assets sales and joint venture formations completed during the 2016 period;

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- Higher interest expense primarily related to financing activities associated with our capital investments;

- Gains recognized during 2016 related to the mark-to-market impact of our Preferred Distribution Rate Reset Option; and

- Lower income tax expense primarily due to lower earnings from our Canadian operations and the impact from the cumulative revaluation of Canadian net deferred tax liabilities resulting from an Alberta, Canada provincial tax rate increase enacted during the comparative 2015 period.

See further discussion of our segment operating results in the "—Results of Operations—Analysis of Operating Segments" and "—Other Income and Expenses" sections below;

We executed a $1.4 billion capital program during 2016, which we expect will contribute to growth in our fee-based Transportation and Facilities segments in future years. In addition, we paid approximately $1.7 billion of cash distributions to our Class A shareholders and noncontrolling interests during 2016.

To improve our ability to manage through the industry downturn and to position for a recovery, we completed a number of initiatives during 2016 to maintain a solid capital structure, significant liquidity and overall financial flexibility. Such initiatives included (i) executing the Simplification Transactions in November 2016, which lowered PAA's incremental cost of equity through the elimination of its IDRs, and in connection therewith resetting PAA's distribution level, which resulted in an annual reduction in consolidated cash distributions of approximately $320 million, (ii) securing approximately $1.6 billion of equity capital through the sale of new PAA Series A preferred units in January 2016, (iii) selectively utilizing PAA's continuous offering program to raise approximately $796 million of net proceeds, (iv) selling non-core assets and entering into strategic joint ventures, which raised approximately $550 million of cash proceeds during 2016 while reducing our capital commitments and (v) entering into a definitive agreement to sell additional assets for approximately $290 million that is expected to close in the first half of 2017, subject to regulatory approvals.

Subsequent to December 31, 2016, we acquired a crude oil gathering system located in the Northern Delaware Basin for approximately $1.215 billion. In addition, in February 2017, we entered into a definitive agreement to form a 50/50 joint venture to acquire a crude oil pipeline located in the Southern Delaware Basin for $133 million. We also entered into definitive sales agreements for two transactions totaling $310 million, and we completed a third transaction, the sale of a partial interest in a pipeline segment, in January 2017 for proceeds of $70 million. We expect the remaining transactions to close during the first half of 2017, subject to customary closing conditions, including receipt of regulatory approvals.

Acquisitions and Capital Projects

We completed a number of acquisitions and capital projects in 2016, 2015 and 2014 that have impacted our results of operations. The following table summarizes our expenditures for acquisition capital, expansion capital and maintenance capital for the periods indicated (in millions):

	Year Ended December 31,		
	2016	2015	2014
Acquisition capital (1)	$ 289	$ 105	$ 1,099
Expansion capital (2)	1,405	2,170	2,026
Maintenance capital (2)	186	220	224
	$ 1,880	$ 2,495	$ 3,349

(1) Acquisitions of initial investments or additional interests in unconsolidated entities are included in "Acquisition capital." Subsequent contributions to unconsolidated entities related to expansion projects of such entities are recognized in "Expansion capital." We account for our investments in such entities under the equity method of accounting.

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

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Acquisitions

Acquisitions are financed using a combination of equity and debt, including borrowings under the PAA commercial paper program or credit facilities and the issuance of PAA senior notes. In addition, we use proceeds from sales of non-core assets for funding. Businesses acquired impact our results of operations commencing on the closing date of each acquisition. Our acquisition, divestiture and capital expansion activities are discussed further in "—Liquidity and Capital Resources." Information regarding acquisitions completed in 2016, 2015 and 2014 is set forth in the table below (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Western Canada NGL Assets	August 2016	$ 204	Transportation and Facilities
Other	Various	85	Transportation
2016 Total		$ 289	
2015 Total	Various	$ 105	Transportation and Facilities
BridgeTex Acquisition (50% interest) (1)	November 2014	$ 1,088	Transportation
Other	Various	11	Facilities
2014 Total		$ 1,099	

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

Alpha Crude Connector Gathering System. In February 2017, we acquired the Alpha Crude Connector ("ACC") gathering system for total consideration of $1.215 billion, subject to working capital and other adjustments. The ACC gathering system is located in the Northern Delaware Basin in Southeastern New Mexico and West Texas and is comprised of 515 miles of recently constructed gathering and transmission lines and five market interconnects, including to our Basin Pipeline at Wink. The ACC gathering system is supported by long-term acreage dedications.

Expansion Capital Projects

Our 2016 projects primarily included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2016, 2015 and 2014 projects (in millions):

Projects	2016	2015	2014
Red River Pipeline (Cushing to Longview) (1)	$306	$143	$—
Permian Basin Area Projects (2)	200	470	378
Fort Saskatchewan Facility Projects / NGL Line (2)	200	272	142
Saddlehorn Pipeline (4)	108	103	—
Diamond Pipeline (2) (5)	104	6	29
Cushing Terminal Expansions (2)	62	39	13
St. James Terminal Expansions (2)	51	45	25
Eagle Ford JV Projects (2) (5)	29	93	117
Cactus Pipeline (2)	26	134	350
Rail Terminal Projects (3)	5	294	239
Other Projects	314	571	733
Total	$1,405	$2,170	$2,026

(1) In January 2017, we sold an undivided 40% interest in a segment of the Red River Pipeline.

(2) These projects will continue into 2017. See "—Liquidity and Capital Resources—Acquisitions, Divestitures and Expansion Capital Expenditures—2017 Capital Projects."

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(3) Includes railcar purchases, as well as rail projects near St. James, LA; Tampa, CO; Bakersfield, CA; Carr, CO; Manitou, ND; Van Hook, ND; Yorktown, VA; and Kerrobert, Canada rail projects.
(4) Represents contributions related to our 40% investment interest in Saddlehorn.
(5) Represents contributions related to our 50% investment interest.

Our recent expansion capital programs were primarily driven by investment in midstream infrastructure projects to address the need for additional takeaway capacity in regions impacted by the increase in crude oil and liquids-rich gas production growth in North America, as well as the long-term needs of both the upstream and downstream sectors of the crude oil space. A majority of the expansion capital spent in the years presented was invested in our fee-based Transportation and Facilities segments.

However, the meaningful decrease in crude oil prices since the second half of 2014 led to production declines and infrastructure overbuild in a number of onshore resource plays. As such, we have reduced our forecasted capital expansion program in 2017 relative to prior years. We currently expect to spend approximately $800 million for expansion capital in 2017. See "—Liquidity and Capital Resources—Acquisitions, Divestitures and Expansion Capital Expenditures—2017 Capital Projects" and "—Market Overview and Outlook" for additional information.

Critical Accounting Policies and Estimates

Critical Accounting Policies

We have adopted various accounting policies to prepare our consolidated financial statements in accordance with GAAP. These critical accounting policies are discussed in Note 2 to our Consolidated Financial Statements.

Critical Accounting Estimates

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

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

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

Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, acreage dedications and other contracts, involves professional judgment and is ultimately based on acquisition models and management's assessment of the value of the assets acquired and, to the extent available, third party assessments. Impairment testing entails estimating future net cash flows relating to the business, based on management's estimate of future revenues, future cash flows and market conditions including pricing, demand, competition, operating costs and other factors, such as weighted average cost of capital. Uncertainties associated with these estimates include changes in production decline rates, production interruptions, fluctuations in refinery capacity or product slates, economic obsolescence factors in the area and potential future sources of cash flow. We cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Resolutions of these uncertainties have resulted, although not material, and in the future may result, in impairments that impact our results of operations and financial condition. See Note 7 to our Consolidated Financial Statements for further discussion of goodwill.

Fair Value of Derivatives. The fair value of a derivative at a particular period end does not reflect the end results of a particular transaction, and will most likely not reflect the gain or loss at the conclusion of a transaction. We reflect estimates for these items based on our internal records and information from third parties. We have commodity derivatives, interest rate derivatives and foreign currency derivatives that are accounted for as assets and liabilities at fair value in our Consolidated Balance Sheets. The valuations of our derivatives that are exchange traded are based on market prices on the applicable exchange on the last day of the period. For our derivatives that are not exchange traded, the estimates we use are based on indicative broker quotations or an internal valuation model. Our valuation models utilize market observable inputs such as price, volatility, correlation and other factors and may not be reflective of the price at which they can be settled due to the lack of a liquid market. Less than 1% of total annual revenues are based on estimates derived from internal valuation models.

We also have embedded derivatives in PAA's preferred units that are accounted for as assets and liabilities at fair value in our Consolidated Balance Sheets. Derivatives related to the embedded derivatives in PAA's preferred units are valued using a model that contains inputs, including PAA common unit price, ten-year U.S. Treasury rates, default probabilities and timing estimates, which involve management judgment.

Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Note 12 to our Consolidated Financial Statements for a discussion regarding our derivatives and risk management activities.

Accruals and Contingent Liabilities. We record accruals or liabilities for, among other things, environmental remediation, natural resource damage assessments, governmental fines and penalties, potential legal claims and fees for legal services associated with loss contingencies, and bonuses. Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Our estimates are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our environmental remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment, the duration of the natural resource damage assessment and the ultimate amount of damages determined, the determination and calculation of fines and penalties, the possibility of existing legal claims giving rise to additional claims and the nature, extent and cost of legal services that will be required in connection with lawsuits, claims and other matters. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. A hypothetical variance of 5% in our aggregate estimate for the accruals and contingent liabilities discussed above would have an impact on earnings of up to approximately $12 million. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Equity-Indexed Compensation Plan Accruals. We accrue compensation expense (referred to herein as equity-indexed compensation expense) for outstanding equity-indexed compensation awards. Under GAAP, we are required to estimate the fair value of our outstanding equity-indexed compensation awards and recognize that fair value as compensation expense over the service period. For equity-indexed compensation awards that contain a performance condition, the fair value of the award is recognized as equity-indexed compensation expense only if the attainment of the performance condition is considered probable. Uncertainties involved in this estimate include the actual unit price at time of vesting, whether or not a performance condition will be attained and the continued employment of personnel with outstanding equity-indexed compensation awards. We cannot provide assurance that the actual fair value of our equity-indexed compensation awards will not vary significantly from estimated amounts.

We recognized equity-indexed compensation expense of $60 million, $27 million and $99 million in 2016, 2015 and 2014, respectively, related to awards granted under our various equity-indexed compensation plans. A hypothetical variance of 5% in our aggregate estimate for the equity-indexed compensation expense would have an impact on net income of less than 1%. See Note 16 to our Consolidated Financial Statements for a discussion regarding our equity-indexed compensation plans.

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

We record retirement obligations associated with tangible long-lived assets based on estimates related to the costs associated with cleaning, purging and in some cases, completely removing the assets and returning the land to its original state. In addition, our estimates include a determination of the settlement date or dates for the potential obligation, which may or may not be determinable. Uncertainties that impact these estimates include the costs associated with these activities and the timing of incurring such costs.

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

- whether there is an event or circumstance that may be indicative of an impairment;
- the grouping of assets;
- the intention of “holding”, “abandoning” or “selling” an asset;
- the forecast of undiscounted expected future cash flow over the asset’s estimated useful life; and
- if an impairment exists, the fair value of the asset or asset group.

As discussed in the “Market Overview and Outlook” section below, the decline in crude oil prices and its impact on certain differentials and downward pressure on production that has occurred since mid-2014 has adversely impacted most companies in the midstream industry, including us. As a result of such adverse market conditions, during 2016, we recognized approximately $80 million of non-cash impairment losses on certain of our long-lived rail and other terminal assets included in our Facilities segment. Despite the modest recovery in the crude oil market in recent months, we continue to monitor appropriate indicators of potential impairment.

We did not recognize any material impairment of long-lived assets during the year ended December 31, 2015. During the year ended December 31, 2014, we recognized impairments of $10 million primarily related to assets that were taken out of service. See Note 5 to our Consolidated Financial Statements for further discussion regarding impairments.

Allowance for Doubtful Accounts. We perform credit evaluations of our customers and grant credit based on past payment history, financial conditions and anticipated industry conditions. Customer payments are regularly monitored and a provision for doubtful accounts is established based on specific situations and overall industry conditions. Our history of bad debt losses has been minimal (less than $2 million in the aggregate over the years ended December 31, 2016, 2015 and 2014) and generally limited to specific customer circumstances; however, credit risks can change suddenly and without notice. See Note 2 to our Consolidated Financial Statements for additional discussion.

Inventory Valuations. Inventory, including long-term inventory, primarily consists of crude oil, NGL and natural gas and is valued at the lower of cost or market, with cost determined using an average cost method within specific inventory pools. At the end of each reporting period, we assess the carrying value of our inventory and use estimates and judgment when making any adjustments necessary to reduce the carrying value to net realizable value. Among the uncertainties that impact our estimates are the applicable quality and location differentials to include in our net realizable value analysis. Additionally, we estimate the upcoming liquidation timing of the inventory. Changes in assumptions made as to the timing of a sale can materially impact net realizable value. During the years ended December 31, 2016, 2015 and 2014, we recorded charges of $3 million, $117 million and $289 million, respectively, related to the valuation adjustment of our crude oil, NGL and natural gas inventory due to declines in prices. See Note 4 to our Consolidated Financial Statements for further discussion regarding inventory.

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Recent Accounting Pronouncements

See Note 2 to our Consolidated Financial Statements for information regarding the effect of recent accounting pronouncements on our consolidated financial statements, including the impact of our adoption of revised debt issuance costs guidance on prior period financial statements.

Results of Operations

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

	Year Ended December 31,			Favorable/(Unfavorable) Variance			
				2016-2015		2015-2014	
	2016	2015	2014	$	%	$	%
Transportation segment adjusted EBITDA (1)	$1,141	$1,056	$979	$85	8 %	$77	8 %
Facilities segment adjusted EBITDA (1)	667	588	597	79	13 %	(9)	(2)%
Supply and Logistics segment adjusted EBITDA (1)	359	568	651	(209)	(37)%	(83)	(13)%
Adjustments:							
Depreciation and amortization of unconsolidated entities	(50)	(45)	(29)	(5)	(11)%	(16)	(55)%
Selected items impacting comparability - segment adjusted EBITDA	(434)	(290)	93	(144)	**	(383)	**
Unallocated general and administrative expenses	(3)	(3)	(6)	—	— %	3	50 %
Depreciation and amortization	(495)	(433)	(386)	(62)	(14)%	(47)	(12)%
Interest expense, net	(480)	(443)	(357)	(37)	(8)%	(86)	(24)%
Other income/(expense), net	33	(7)	(2)	40	**	(5)	**
Income tax expense	(78)	(182)	(212)	104	57 %	30	14 %
Net income	660	809	1,328	(149)	(18)%	(519)	(39)%
Net income attributable to noncontrolling interests	(566)	(691)	(1,258)	125	18 %	567	45 %
Net income attributable to PAGP	$94	$118	$70	$(24)	(20)%	$48	69 %
Basic net income per Class A share	$0.94	$1.41	$1.28	$(0.47)	(33)%	$0.13	10 %
Diluted net income per Class A share	$0.94	$1.41	$1.25	$(0.47)	(33)%	$0.16	13 %
Basic weighted average Class A shares outstanding	99	83	54	16	19 %	29	54 %
Diluted weighted average Class A shares outstanding	99	83	244	16	19 %	(161)	(66)%

** Indicates that variance as a percentage is not meaningful.

(1) Segment adjusted EBITDA is the measure of segment performance that is utilized by our Chief Operating Decision Maker ("CODM") to assess performance and allocate resources among our operating segments. This measure is adjusted for certain items, including those that our CODM believes impact comparability of results across periods. See Note 19 to our Consolidated Financial Statements for additional discussion of such adjustments.

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Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures known as “non-GAAP financial measures” in its evaluation of past performance and prospects for the future. The primary additional measure used by management is earnings before interest, taxes, depreciation and amortization (including our proportionate share of depreciation and amortization of unconsolidated entities) and adjusted for certain selected items impacting comparability (“Adjusted EBITDA”).

Management believes that the presentation of such additional financial measure provides useful information to investors regarding our performance and results of operations because this measure, when used to supplement related GAAP financial measures, (i) provide additional information about our core operating performance, (ii) provide investors with the same financial analytical framework upon which management bases financial, operational, compensation and planning/budgeting decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. This non-GAAP measure may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) the mark-to-market of derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), the mark-to-market related to our Preferred Distribution Rate Reset Option, gains and losses on derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable, (iii) long-term inventory costing adjustments, (iv) items that are not indicative of our core operating results and business outlook and/or (v) other items that we believe should be excluded in understanding our core operating performance. This measure may further be adjusted to include amounts related to deficiencies associated with minimum volume commitments whereby we have billed the counterparties for their deficiency obligation and such amounts are recognized as deferred revenue in “Accounts payable and accrued liabilities” on our Consolidated Financial Statements. Such amounts are presented net of applicable amounts subsequently recognized into revenue. We have defined all such items as “selected items impacting comparability.” We do not necessarily consider all of our selected items impacting comparability to be non-recurring, infrequent or unusual, but we believe that an understanding of these selected items impacting comparability is material to the evaluation of our operating results and prospects.

Although we present selected items impacting comparability that management considers in evaluating our performance, you should also be aware that the items presented do not represent all items that affect comparability between the periods presented. Variations in our operating results are also caused by changes in volumes, prices, exchange rates, mechanical interruptions, acquisitions, expansion projects and numerous other factors as discussed, as applicable, in “Analysis of Operating Segments.”

Our definition and calculation of certain non-GAAP financial measures may not be comparable to similarly-titled measures of other companies. Adjusted EBITDA is reconciled to Net Income, the most directly comparable measure as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our Consolidated Financial Statements and footnotes.

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The following table sets forth the reconciliation of our non-GAAP financial performance measure from Net Income (in millions):

	Year Ended December 31,			Favorable/(Unfavorable) Variance			
				2016-2015		2015-2014	
	2016	2015	2014	$	%	$	%
Net income	$660	809	$1,328	$(149)	(18)%	$(519)	(39)%
Add/(Subtract):							
Interest expense, net	480	443	357	37	8 %	86	24 %
Income tax expense	78	182	212	(104)	(57)%	(30)	(14)%
Depreciation and amortization	495	433	386	62	14 %	47	12 %
Depreciation and amortization of unconsolidated entities (1)	50	45	29	5	11 %	16	55 %
Selected Items Impacting Comparability - Adjusted EBITDA:							
(Gains)/losses from derivative activities net of inventory valuation adjustments (2)	404	110	(243)	294	267 %	353	145 %
Deficiencies under minimum volume commitments, net (3)	46	—	—	46	N/A	—	N/A
Long-term inventory costing adjustments (4)	(58)	99	85	(157)	(159)%	14	16 %
Equity-indexed compensation expense (5)	33	27	56	6	22 %	(29)	(52)%
Net (gain)/loss on foreign currency revaluation (6)	9	(29)	9	38	131 %	(38)	(422)%
Line 901 incident (7)	—	83	—	(83)	(100)%	83	N/A
Selected Items Impacting Comparability - segment adjusted EBITDA	434	290	(93)	144	**	383	**
Gains from derivative activities (2)	(30)	—	—	(30)	N/A	—	N/A
Net (gain)/loss on foreign currency revaluation (6)	(1)	8	4	(9)	(113)%	4	100 %
Selected Items Impacting Comparability - Adjusted EBITDA (8)	403	298	(89)	105	**	387	**
Adjusted EBITDA (8)	$2,166	$2,210	$2,223	$(44)	(2)%	$(13)	(1)%

** Indicates that variance as a percentage is not meaningful.

(1) Over the past several years, we have increased our participation in pipeline strategic joint ventures, which are accounted for under the equity method of accounting. Our proportionate share of the depreciation and amortization expense associated with such unconsolidated entities is excluded when reviewing Adjusted EBITDA, similar to our consolidated pipelines.

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

(3) We have certain agreements that require counterparties to deliver, transport or throughput a minimum volume over an agreed upon period. Substantially all of such agreements were entered into with counterparties to economically

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support the return on our capital expenditure necessary to construct the related asset. Some of these agreements include make-up rights if the minimum volume is not met. We record a receivable from the counterparty in the period that services are provided or when the transaction occurs, including amounts for deficiency obligations from counterparties associated with minimum volume commitments. If a counterparty has a make-up right associated with a deficiency, we defer the revenue attributable to the counterparty's make-up right and subsequently recognize the revenue at the earlier of when the deficiency volume is delivered or shipped, when the make-up right expires or when it is determined that the counterparty's ability to utilize the make-up right is remote. We include the impact of amounts billed to counterparties for their deficiency obligation, net of applicable amounts subsequently recognized into revenue, as a selected item impacting comparability. We believe the inclusion of the contractually committed revenues associated with that period is meaningful to investors as the related asset has been constructed, is standing ready to provide the committed service and the fixed operating costs are included in the current period results. Amounts for years prior to 2016 were not significant.

(4) We carry crude oil and NGL inventory that is comprised of minimum working inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. Therefore, we classify this inventory as long-term on our balance sheet and do not hedge the inventory with derivative instruments (similar to linefill in our own assets). We treat the impact of changes in the average cost of the long-term inventory (that result from fluctuations in market prices) and writedowns of such inventory that result from price declines as a selected item impacting comparability. See Note 4 to our Consolidated Financial Statements for additional inventory disclosures.

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

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

(7) Includes costs recognized during the period related to the Line 901 incident that occurred in May 2015, net of amounts we believe are probable of recovery from insurance. See Note 17 to our Consolidated Financial Statements for additional information.

(8) Adjusted EBITDA includes Other income/(expense), net adjusted for selected items impacting comparability. Segment adjusted EBITDA is exclusive of such amounts.

Analysis of Operating Segments

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. Our CODM (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment adjusted EBITDA, segment volumes, segment adjusted EBITDA per barrel and maintenance capital investment.

During the fourth quarter of 2016, we modified our primary segment performance measure to segment adjusted EBITDA from segment profit, and thus prior period segment disclosures have been recast to reflect this change. Segment adjusted EBITDA forms the basis of our internal financial reporting and is the measure of segment performance that is utilized by our CODM in assessing performance and allocating resources among our operating segments. Such recasts have no impact on previously reported consolidated financial results.

We define segment adjusted EBITDA as revenues and equity earnings in unconsolidated entities less (a) purchases and related costs, (b) field operating costs and (c) segment general and administrative expenses, plus our proportionate share of the depreciation and amortization expense of unconsolidated entities, and further adjusted for certain selected items including (i) the mark-to-market of derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), gains and losses on derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable, (ii) long-term inventory costing adjustments, (iii) charges for

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obligations that are expected to be settled with the issuance of equity instruments, (iv) amounts related to deficiencies associated with minimum volume commitments, net of applicable amounts subsequently recognized into revenue and (v) other items that our CODM believes are integral to understand our core segment operating performance. See Note 19 to our Consolidated Financial Statements for a reconciliation of segment adjusted EBITDA to net income attributable to PAGP.

Our segment analysis involves an element of judgment relating to the allocations between segments. In connection with its operations, the Supply and Logistics segment secures transportation and facilities services from our other two segments as well as third-party service providers under month-to-month and multi-year arrangements. Intersegment transportation service rates are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market. Facilities segment services are also obtained at rates generally consistent with rates charged to third parties for similar services; however, certain terminalling and storage rates are discounted to our Supply and Logistics segment to reflect the fact that these services may be canceled on short notice to enable the Facilities segment to provide services to third parties. Intersegment activities are eliminated in consolidation and we believe that the estimates with respect to these rates are reasonable. Also, our segment operating and general and administrative expenses reflect direct costs attributable to each segment; however, we also allocate certain operating expenses and general and administrative overhead expenses between segments based on management's assessment of the business activities for the period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period. We believe that the estimates with respect to these allocations are reasonable.

Revenues and expenses from our Canadian based subsidiaries, which use CAD as their functional currency, are translated at the prevailing average exchange rates for each month.

Transportation Segment

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

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The following tables set forth our operating results from our Transportation segment:

Operating Results [1]	Year Ended December 31,			Favorable/(Unfavorable) Variance			
				2016-2015		2015-2014	
(in millions, except per barrel data)	2016	2015	2014	$	%	$	%
Revenues							
Tariff activities	$1,436	$1,439	$1,447	$(3)	— %	$(8)	(1)%
Trucking	148	155	208	(7)	(5)%	(53)	(25)%
Total transportation revenues	1,584	1,594	1,655	(10)	(1)%	(61)	(4)%
Costs and expenses							
Trucking costs	(94)	(108)	(151)	14	13 %	43	28 %
Field operating costs [2]	(537)	(652)	(560)	115	18 %	(92)	(16)%
Equity-indexed compensation expense - field operating costs	(14)	(5)	(15)	(9)	(180)%	10	67 %
Segment general and administrative expenses [2] [3]	(88)	(89)	(83)	1	1 %	(6)	(7)%
Equity-indexed compensation expense - general and administrative	(15)	(6)	(29)	(9)	(150)%	23	79 %
Equity earnings in unconsolidated entities	195	183	108	12	7 %	75	69 %
Adjustments [4]:							
Depreciation and amortization of unconsolidated entities	50	45	29	5	11 %	16	55 %
Deficiencies under minimum volume commitments, net	44	—	—	44	N/A	—	N/A
Line 901 incident	—	83	—	(83)	(100)%	83	N/A
Equity-indexed compensation expense	16	11	25	5	45 %	(14)	(56)%
Segment adjusted EBITDA	$1,141	$1,056	$979	$85	8 %	$77	8 %
Maintenance capital	$121	$144	$165	$(23)	(16)%	$(21)	(13)%
Segment adjusted EBITDA per barrel	$0.67	$0.65	$0.66	$0.02	3 %	$(0.01)	(2)%

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Average Daily Volumes	Year Ended December 31,			Favorable/(Unfavorable) Variance			
				2016-2015		2015-2014	
(in thousands of barrels per day) [5]	2016	2015	2014	Volumes	%	Volumes	%
Tariff activities volumes							
Crude oil pipelines (by region):							
Permian Basin [6]	2,146	1,849	1,512	297	16 %	337	22 %
South Texas / Eagle Ford [6]	284	306	227	(22)	(7)%	79	35 %
Western	188	215	260	(27)	(13)%	(45)	(17)%
Rocky Mountain [6]	449	440	426	9	2 %	14	3 %
Gulf Coast	497	532	492	(35)	(7)%	40	8 %
Central [6]	394	413	450	(19)	(5)%	(37)	(8)%
Canada	381	392	399	(11)	(3)%	(7)	(2)%
Crude oil pipelines	4,339	4,147	3,766	192	5 %	381	10 %
NGL pipelines	184	193	186	(9)	(5)%	7	4 %
Tariff activities total volumes	4,523	4,340	3,952	183	4 %	388	10 %
Trucking volumes	114	113	127	1	1 %	(14)	(11)%
Transportation segment total volumes	4,637	4,453	4,079	184	4 %	374	9 %

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

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

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

(4) Represents adjustments included in the performance measure utilized by our CODM in the evaluation of segment results. See Note 19 to our Consolidated Financial Statements for additional discussion of such adjustments.

(5) Average daily volumes are calculated as the total volumes (attributable to our interest) for the year divided by the number of days in the year.

(6) Area systems include volumes (attributable to our interest) from pipelines owned by unconsolidated entities.

Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment results generated by our tariff and other fee-related activities depend on the volumes transported on the pipeline and the level of the tariff and other fees charged as well as the fixed and variable field costs of operating the pipeline. As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor that is intended to offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative-related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff activities revenues.

The following is a discussion of items impacting Transportation segment operating results for the periods indicated.

Revenues from Tariff Activities, Equity Earnings in Unconsolidated Entities and Volumes. The following table presents variances in tariff activities revenues and equity earnings in unconsolidated entities by region for the comparative periods presented:

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(in millions)	Favorable/(Unfavorable) Variance 2016-2015 Revenues	Favorable/(Unfavorable) Variance 2016-2015 Equity Earnings	Favorable/(Unfavorable) Variance 2015-2014 Revenues	Favorable/(Unfavorable) Variance 2015-2014 Equity Earnings
Tariff activities:				
Permian Basin region	$ 98	$ 7	$ 75	$ 52
South Texas / Eagle Ford region	(7)	(1)	12	19
Western region	(6)	—	(24)	—
Rocky Mountain region	(18)	10	7	10
Gulf Coast region	(19)	—	10	—
Central region	(23)	2	(8)	—
Canada crude oil	(2)	—	(16)	—
NGL	11	—	(2)	—
Other (including pipeline loss allowance revenue)	(37)	(6)	(62)	(6)
Total variance	$ (3)	$ 12	$ (8)	$ 75

- Permian Basin region. The increase in revenues for 2016 compared to 2015 was primarily driven by (i) higher volumes associated with the expansion of our pipeline systems in the Delaware Basin, (ii) higher volumes on our takeaway pipelines and (iii) a full year of service of our Cactus pipeline, which was placed in service in April 2015. Revenues increased for 2015 over 2014 primarily due to (i) results from our Cactus pipeline and (ii) higher volumes related to increased production, primarily associated with the expansion of our pipeline system in the Delaware Basin. The increase in equity earnings for 2015 over 2014 was driven by earnings from our interest in BridgeTex, which we acquired in November 2014.

- South Texas / Eagle Ford region. Revenues decreased in 2016 compared to 2015 due to production declines in the region. Revenues increased for 2015 over 2014 due to higher volumes driven by the extension of our gathering system and increased production. Equity earnings increased for 2015 over 2014 due to higher earnings from our interest in Eagle Ford Pipeline LLC, primarily driven by higher throughput on the Eagle Ford pipeline system. The higher throughput was due to a combination of (i) the connection to our Cactus pipeline in April 2015 and (ii) increased crude oil production in the Eagle Ford region.

- Western region. Revenues and volumes decreased for each of the comparative periods presented primarily due to pipeline downtime on our All American Pipeline associated with the Line 901 incident that occurred in the second quarter of 2015. See Note 17 to our Consolidated Financial Statements for additional information regarding this incident.

- Rocky Mountain region. The decrease in revenues for 2016 compared to 2015 was largely driven by (i) lower volumes due to production declines and increased competition and (ii) the sale of 50% of our investment in Cheyenne Pipeline in June 2016, subsequent to which it was accounted for under the equity method of accounting.

Equity earnings increased for 2016 over 2015 due to earnings from (i) our 40% investment in the entity that owns Saddlehorn Pipeline, a segment of which was placed in service in the third quarter of 2016, and (ii) our 50% investment in Cheyenne Pipeline, as discussed above.

The increase in equity earnings for 2015 compared to 2014 was driven by higher earnings from our interest in White Cliffs, primarily as a result of increased throughput on the White Cliffs pipeline due to an expansion of the pipeline that was placed into service in July 2014.

- Gulf Coast region. Revenues and volumes decreased for 2016 compared to 2015 primarily due to the sale of certain of our Gulf Coast pipelines in March and July 2016. These decreases were partially offset by increased volumes on the

Capline and Pascagoula pipelines, which were favorably impacted by higher refinery demand, but were at lower tariff rates than the pipelines that were sold.

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The increase in revenues for 2015 over 2014 was primarily driven by (i) results from our Pascagoula pipeline, which was placed in service in April 2014, and which also favorably impacted volumes and demand for storage on our Mississippi/Alabama system, and (ii) higher volumes on Capline due to higher refinery demand.

- Central region. The decrease in revenues for 2016 compared to 2015 was largely driven by lower volumes due to production declines in the Mid-Continent area, as well as the sale of 50% of our investment in STACK in August 2016, subsequent to which it was accounted for under the equity method of accounting.

- Canada. Revenues decreased for 2016 as compared to 2015 and for 2015 as compared to 2014 due to unfavorable foreign exchange impacts of $9 million and $38 million, respectively, which more than offset revenue increases from higher tariff rates on certain of our pipelines and related system assets in each of the comparative periods.

- NGL pipelines. Revenues increased for 2016 as compared to 2015 primarily due to contributions from the Western Canada NGL assets we acquired in August 2016.

Revenues and volumes from our NGL pipelines were relatively consistent for 2015 compared to 2014, as higher revenue from tariff rate increases was substantially offset by unfavorable foreign exchange fluctuation impacts of $12 million.

- Other. The variances for the comparative periods presented were related to pipeline loss allowance revenue. Loss allowance revenue decreased for the comparative periods presented due to a lower average realized price per barrel. The decrease in loss allowance revenue for 2015 compared to 2014 was partially offset by higher volumes.

Adjustments: Deficiencies under minimum volume commitments, net. Many industry infrastructure projects developed and completed over the last several years were underpinned by long-term minimum volume commitment contracts whereby the shipper, based on an expectation of continued production growth, agreed to either: (i) ship and pay for certain stated volumes or (ii) pay the agreed upon price for a minimum contract quantity. The activity for 2016 presented in the table above primarily reflects the amounts billed in 2016 under minimum volume commitment contracts. Such amounts were not material to periods prior to 2016 and, thus, are not included in the table for prior years.

Adjustments: Depreciation and amortization of unconsolidated entities. The increases for the periods presented were primarily driven by additional depreciation expense associated with newly acquired or completed joint venture pipeline projects.

Trucking Revenues. Trucking revenues for the comparative periods presented were unfavorably impacted by foreign exchange fluctuation impacts of $5 million and $28 million, respectively. The decrease in trucking revenues for 2015 compared to 2014 was further unfavorably impacted by lower producer volumes.

Trucking Costs. The decrease in trucking costs for 2016 compared to 2015 was primarily driven by lower contract services rates. The decrease in trucking costs for 2015 compared to 2014 was primarily driven by lower producer volumes, as discussed above. Trucking costs for the comparative periods presented were further favorably impacted by foreign exchange fluctuation impacts of $4 million and $20 million, respectively.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) decreased for the year ended December 31, 2016 compared to the year ended December 31, 2015 primarily due to net costs of approximately $83 million associated with the Line 901 incident that were recognized during 2015. See Note 17 to our Consolidated Financial Statements for additional information regarding this incident. The decrease in field operating costs was further driven by lower utilities and maintenance costs, costs associated with the MP 29 release during 2015, lower operating costs due to the sale of certain of our Gulf Coast pipelines in March and July 2016 and a favorable foreign exchange impact of $5 million, partially offset by an increase in insurance premiums.

The increase in field operating costs (excluding equity-indexed compensation expense) for the year ended December 31, 2015 compared to the year ended December 31, 2014 was primarily due to the estimated costs of $83 million recognized during 2015 associated with the Line 901 incident, net of amounts we believe are probable of recovery from insurance. The increase in field operating costs was also driven by (i) higher salary and related expenses and property tax expense primarily associated with new assets placed in service in 2015 and (ii) higher maintenance and repairs cost, partially offset by favorable foreign exchange impacts of $22 million.

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Segment General and Administrative Expenses. The increase in segment general and administrative expenses (excluding equity-indexed compensation expense) for the year ended December 31, 2015 over the year ended December 31, 2014 was primarily due to increased salaries, benefits and other costs associated with the growth in the segment, partially offset by a $4 million favorable foreign exchange impact.

Equity-Indexed Compensation Expense. The following table presents total equity-indexed compensation expense by segment (in millions):

	Year Ended December 31,			Favorable/(Unfavorable) Variance	
Operating Segment	2016	2015	2014	2016-2015	2015-2014
Transportation	$ 29	$ 11	$ 44	$ (18)	$ 33
Facilities	15	5	24	(10)	19
Supply and Logistics	16	11	30	(5)	19
	$ 60	$ 27	$ 98	$ (33)	$ 71

Across all segments, equity-indexed compensation expense increased by $33 million for the year ended December 31, 2016 compared to the year ended December 31, 2015, primarily due to the impact of the increase in PAA unit price during the year ended December 31, 2016 compared to the impact of the decrease in PAA unit price during the year ended December 31, 2015, partially offset by the impact of fewer average probable awards outstanding and lower average values per award during the 2016 period compared to the same period in 2015. Across all segments, equity-indexed compensation expense decreased by $71 million for the year ended December 31, 2015 compared to the year ended December 31, 2014, primarily due to the impact of the decrease in PAA unit price during the year ended December 31, 2015 compared to the impact of the decrease in PAA unit price during the year ended December 31, 2014. See Note 16 to our Consolidated Financial Statements for additional information regarding our equity-indexed compensation plans.

Allocations of equity-indexed compensation expense vary over time between field operating costs and general and administrative expenses, as well as between segments, and could result in variances in those expense categories or segments that differ from the consolidated variance explanations above.

Adjustments: Equity-Indexed Compensation Expense. The equity-indexed compensation expense selected item adjustment is primarily associated with equity-classified awards, which are not impacted by changes in unit price. Therefore, the impact of unit price changes is less on the equity-indexed compensation expense selected item adjustment than on equity-indexed compensation expense as a whole.

Maintenance Capital. Maintenance capital consists of capital expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets. The decrease in maintenance capital for the year ended December 31, 2016 compared to the year ended December 31, 2015 was primarily driven by completion of several large projects in earlier years and lower third party service costs.

The decrease in maintenance capital in 2015 compared to 2014 was primarily due to a reclassification of certain maintenance capital costs from our Facilities segment during the 2014 period. In addition, the decrease in maintenance capital was impacted by favorable foreign exchange rate fluctuations.

Facilities Segment

Our Facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products, NGL and natural gas, as well as NGL fractionation and isomerization services and natural gas and condensate processing services. The Facilities segment generates revenue through a combination of month-to-month and multi-year agreements.

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The following tables set forth our operating results from our Facilities segment:

Operating Results [1] (in millions, except per barrel data)	Year Ended December 31, 2016	2015	2014	Favorable/(Unfavorable) Variance 2016-2015 $	%	2015-2014 $	%
Revenues	$1,107	$1,050	$1,127	$57	5 %	$(77)	(7)%
Natural gas related storage costs	(26)	(24)	(55)	(2)	(8)%	31	56 %
Field operating costs [2]	(347)	(377)	(404)	30	8 %	27	7 %
Equity-indexed compensation expense - field operating costs	(5)	—	(4)	(5)	N/A	4	100 %
Segment general and administrative expenses [2] [3]	(58)	(65)	(60)	7	11 %	(5)	(8)%
Equity-indexed compensation expense - general and administrative	(10)	(5)	(20)	(5)	(100)%	15	75 %
Adjustments [4]	6	9	13	(3)	(33)%	(4)	(31)%
Segment adjusted EBITDA	$667	$588	$597	$79	13 %	$(9)	(2)%
Maintenance capital	$55	$68	$52	$(13)	(19)%	$16	31 %
Segment adjusted EBITDA per barrel	$0.43	$0.39	$0.41	$0.04	10 %	$(0.02)	(5)%

Volumes [5]	Year Ended December 31, 2016	2015	2014	Favorable/(Unfavorable) Variance 2016-2015 Volumes	%	2015-2014 Volumes	%
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	107	100	95	7	7 %	5	5 %
Rail load / unload volumes (average volumes in thousands of barrels per day)	83	210	231	(127)	(60)%	(21)	(9)%
Natural gas storage (average monthly working capacity in billions of cubic feet)	97	97	97	—	— %	—	— %
NGL fractionation (average volumes in thousands of barrels per day)	115	103	96	12	12 %	7	7 %
Facilities segment total volumes (average monthly volumes in millions of barrels) [6]	129	126	121	3	2 %	5	4 %

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

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

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

(4) Represents adjustments included in the performance measure utilized by our CODM in the evaluation of segment results. See Note 19 to our Consolidated Financial Statements for additional discussion of such adjustments.

(5) Average monthly volumes are calculated as total volumes for the year divided by the number of months in the year.

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

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crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iv) NGL fractionation volumes multiplied by the number of days in the year and divided by the number of months in the year.

The following is a discussion of items impacting Facilities segment operating results for the periods indicated.

Revenues and Volumes. Variances in revenues and average monthly volumes for the comparative periods were primarily driven by:

- NGL Storage, NGL Fractionation and Canadian Gas Processing — Revenues increased by $53 million for the year ended December 31, 2016 over the same 2015 period primarily due to (i) contributions from the Western Canada NGL assets we acquired in August 2016, (ii) contributions from ongoing expansion projects at our Fort Saskatchewan facility and (iii) higher fees at certain of our NGL storage and fractionation facilities. Such increases were partially offset by unfavorable foreign exchange fluctuation impacts of $10 million, which were largely offset in our Supply and Logistics segment results.

Revenues decreased by $7 million for the year ended December 31, 2015 compared to the year ended December 31, 2014. This decrease was primarily due to estimated unfavorable foreign exchange fluctuation impacts of $41 million, which offset revenue increases from higher facility fees for the 2015 period. These impacts were largely offset in our Supply and Logistics segment results.

- Crude Oil Storage — Revenues increased by $24 million for the year ended December 31, 2016 over the year ended December 31, 2015 primarily due to (i) aggregate capacity expansions of approximately 4 million barrels at our St. James and Cushing terminals and (ii) increased utilization at certain of our West Coast terminals. Such increases were partially offset by lower results due to the sale of certain of our East Coast terminals in April 2016.

For the year ended December 31, 2015, revenues increased by $9 million over the year ended December 31, 2014 primarily due to capacity expansions of approximately 1 million barrels and higher marine access activity at our St. James terminal.

- Rail Terminals — Revenues decreased by $17 million for the year ended December 31, 2016 compared to the year ended December 31, 2015 primarily due to (i) lower volumes at our U.S. terminals as a result of production declines in the Bakken and less favorable market conditions, partially offset by (i) revenue associated with minimum volume commitments at certain of our terminals and (ii) revenues and volumes from our Canadian NGL rail terminal that came online in April 2016.

For the year ended December 31, 2015, revenues decreased by $26 million compared to the year ended December 31, 2014 due to lower volumes and lower rail fees related to the movement of certain volumes of Bakken crude oil, partially offset by revenues from our Bakersfield rail terminal that came online in the fourth quarter of 2014.

- Gulf Coast Gas Processing — Revenues decreased by $13 million for the year ended December 31, 2015 compared to the same 2014 period, primarily due to lower volumes and decreased margins driven by lower commodity prices. Revenues remained relatively consistent for the year ended December 31, 2016 compared to the same 2015 period.

- Natural Gas Storage Operations — Net revenues decreased by $12 million for the year ended December 31, 2015 compared to the year ended December 31, 2014 primarily due to (i) declines in market rates for natural gas storage, which resulted in lower rates on new contracts replacing expiring contracts, and (ii) reduced hub services opportunities. In addition, the 2014 period was unfavorably impacted by costs incurred to manage deliverability requirements in conjunction with the extended period of severe cold weather experienced during the first quarter of 2014. Revenues remained relatively consistent for the year ended December 31, 2016 compared to the same 2015 period.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) decreased for the year ended December 31, 2016 compared to the same 2015 period due to (i) lower costs related to contract services, largely at our rail terminals and, to a lesser extent, at our processing facilities, (ii) the impact of the sale of certain of our East Coast terminals in April 2016, (iii) lower turnaround and inspection costs and (iv) favorable foreign exchange fluctuation impacts of $4 million. Such decreases were partially offset by an increase in operating costs due to the Western Canada NGL assets acquired in August 2016.

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The decrease in field operating costs (excluding equity-indexed compensation expenses) for the year ended December 31, 2015 compared to the year ended December 31, 2014 was primarily due to (i) decreased maintenance and repairs cost, (ii) lower gas and power costs largely associated with our NGL fractionation and Canadian gas processing activities and (iii) favorable foreign exchange fluctuation impacts of $19 million. Such decreases were partially offset by an increase in expenses associated with new assets placed in service.

Segment General and Administrative Expenses. Segment general and administrative expenses (excluding equity-indexed compensation expense) decreased for the year ended December 31, 2016 compared to the year ended December 31, 2015 due to cost reduction efforts and lower expenses incurred for legal fees.

The increase in general and administrative expenses (excluding equity-indexed compensation expenses) for the year ended December 31, 2015 compared to the year ended December 31, 2014 was primarily due to increased salaries and benefits, partially offset by a $3 million favorable foreign exchange fluctuation impact.

Equity-indexed compensation expense. See "—Analysis of Operating Segments—Transportation Segment" for discussion of equity-indexed compensation expense for the periods presented.

Maintenance Capital. The decrease in maintenance capital for 2016 compared to 2015 was primarily due to lower spending on various tank and other maintenance capital projects, partially due to the timing of certain 2015 projects at our NGL storage and fractionation facilities.

The increase in maintenance capital in 2015 over 2014 was primarily due to various tank and facility projects and timing of equipment replacements, as well as the impact from a change in classification of certain maintenance capital costs to our Transportation segment in the 2014 period.

Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, as well as sales of NGL volumes purchased from suppliers and natural gas sales attributable to the activities performed by our natural gas storage commercial optimization group. Generally, our segment results are impacted by (i) increases or decreases in our Supply and Logistics segment volumes (which consist of lease gathering crude oil purchases volumes, NGL sales volumes and waterborne cargos), (ii) the effects of competition on our lease gathering margins and (iii) the overall volatility and strength or weakness of market conditions and the allocation of our assets among our various risk management strategies. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. Although our segment results may be adversely affected during certain transitional periods as discussed further below, our crude oil and NGL supply, logistics and distribution operations are not directly affected by the absolute level of prices, but are affected by overall levels of supply and demand for crude oil and NGL and relative fluctuations in market-related indices.

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The following tables set forth our operating results from our Supply and Logistics segment:

Operating Results [1]	Year Ended December 31,			Favorable/(Unfavorable) Variance			
				2016-2015		2015-2014	
(in millions, except per barrel data)	2016	2015	2014	$	%	$	%
Revenues	$19,018	$21,945	$42,150	$(2,927)	(13)%	$(20,205)	(48)%
Purchases and related costs	(18,627)	(21,018)	(40,752)	2,391	11%	19,734	48%
Field operating costs [2]	(291)	(433)	(481)	142	33%	48	10%
Equity-indexed compensation expense - field operating costs	(1)	—	(2)	(1)	N/A	2	100%
Segment general and administrative expenses [2] [3]	(93)	(102)	(105)	9	9%	3	3%
Equity-indexed compensation expense - general and administrative	(15)	(11)	(28)	(4)	(36)%	17	61%
Adjustments [4]:							
(Gains)/losses from derivative activities net of inventory valuation adjustments	406	106	(243)	300	283%	349	144%
Long-term inventory costing adjustments	(58)	99	85	(157)	(159)%	14	16%
Net (gain)/loss on foreign currency revaluation	10	(29)	9	39	134%	(38)	(422)%
Equity-indexed compensation expense	10	11	18	(1)	(9)%	(7)	(39)%
Segment adjusted EBITDA	$359	$568	$651	$(209)	(37)%	$(83)	(13)%
Maintenance capital	$10	$8	$7	$2	25%	$1	14%
Segment adjusted EBITDA per barrel	$0.85	$1.33	$1.54	$(0.48)	(36)%	$(0.21)	(14)%

Average Daily Volumes	Year Ended December 31,			Favorable (Unfavorable) Variance			
				2016-2015		2015-2014	
(in thousands of barrels per day)	2016	2015	2014	Volume	%	Volume	%
Crude oil lease gathering purchases	894	943	949	(49)	(5)%	(6)	(1)%
NGL sales	259	223	208	36	16%	15	7%
Waterborne cargos	7	2	—	5	250%	2	N/A
Supply and Logistics segment total volumes	1,160	1,168	1,157	(8)	(1)%	11	1%

(1) Revenues and costs include intersegment amounts.

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

(3)