PLAINS GP HOLDINGS LP
Form 10-K
February 25, 2016
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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, 2015

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

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

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

Title of Each Class	Name of Each Exchange on Which Registered
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 $5.8 billion on June 30, 2015, based on a closing price of $25.84 per Class A share as reported on the New York Stock Exchange on such date.

As of February 12, 2016, there were 244,203,443 Class A shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

NONE

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PLAINS GP HOLDINGS, L.P. AND SUBSIDIARIES

FORM 10-K 2015 ANNUAL REPORT

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FORWARD-LOOKING STATEMENTS

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements incorporating the words anticipate, believe, estimate, expect, plan, intend and forecast, as well as similar expressions and st regarding our business strategy, plans and objectives for future operations. The absence of 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, refined product 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, 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;
- failure to implement or capitalize, or delays in implementing or capitalizing, on expansion projects;
- unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transportation throughput requirements;

- the occurrence of a natural disaster, catastrophe, terrorist attack or other event, including attacks on our electronic and computer systems;
- tightened capital markets or other factors that increase our cost of capital or limit our 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 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;
- maintenance of PAA s credit rating and ability to receive open credit from suppliers and trade counterparties;
- non-utilization of our assets and facilities;
- 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 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;
- increased costs, or lack of availability, of insurance;
- the effectiveness of our risk management activities;

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- 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;

- 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;

- 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;

- 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.

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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 to own an interest in the general partner and incentive distribution rights (IDRs) of Plains All American Pipeline, L.P (PAA), a publicly traded Delaware limited partnership. Although formed as a limited partnership, PAGP has elected to be taxed as a corporation for United States federal income tax purposes. As used in this Form 10-K and unless the context indicates otherwise (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. 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, 2015, we owned an approximate 38% limited partner interest in AAP (an approximate 35% economic interest), and the remaining limited partner interests in AAP were held by the owners of AAP immediately prior to our IPO (the Legacy Owners). AAP is a Delaware limited partnership that directly owns all of PAA s IDRs and indirectly owns the 2% general partner interest in PAA. AAP is the sole member of PAA GP LLC (PAA GP), a Delaware limited liability company that directly holds the 2% general partner interest in PAA. Plains All American GP LLC (GP LLC) is a Delaware limited liability company that holds the general partner interest in AAP. Also, through a series of transactions prior to our IPO with PAA GP Holdings LLC (our general partner) and the owners of GP LLC, GP LLC s general partner interest in AAP became a non-economic interest and we became the owner of a 100% managing member interest in GP LLC.

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.

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

The two charts below show the structure and ownership of PAGP and certain subsidiaries as of December 31, 2015 in both a summarized and more detailed format. The first chart depicts PAGP s legal structure in summary format, while the second chart depicts a more comprehensive view of PAGP s legal structure, including ownership and economic interests and shares and units outstanding.

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Summarized Partnership Structure

(as of December 31, 2015) (1)

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(1) In January 2016, PAA completed the sale of approximately 61.0 million Series A Convertible Preferred Units representing limited partner interests in PAA. See Note 10 to our Consolidated Financial Statements for additional information.

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

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Detailed Partnership Structure

(as of December 31, 2015) (1)

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(1) In January 2016, PAA completed the sale of approximately 61.0 million Series A Convertible Preferred Units representing limited partner interests in PAA. See Note 10 to our Consolidated Financial Statements for additional information.

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

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

(4) Represents the number of Class A units of AAP (AAP units) for which the Class B units of AAP (referred to herein as the AAP Management Units) would be exchangeable, assuming a conversion rate of approximately 0.938 AAP units for each AAP Management Unit as of December 31, 2015. The AAP Management Units are entitled to certain proportionate distributions paid by AAP.

(5) As of December 31, 2015, we owned approximately 38% of the membership interests in our general partner, which percentage corresponds to our ownership percentage of AAP units (approximately 38%, representing an approximate 35% economic interest in AAP, including the dilutive effect of the AAP Management Units).

Our Business

As of December 31, 2015, our only cash-generating assets consisted of 229,278,980 AAP units, which represent an approximate 38% limited partner interest in AAP (approximately 35% economic interest including the dilutive effect of the AAP Management Units). Unless we directly acquire and hold assets or businesses in the future, our cash flows will be generated solely from the cash distributions we receive from AAP. AAP does not own any common units in PAA and currently receives all of its cash flows from distributions on its direct ownership of PAA s IDRs and its indirect ownership of PAA s 2% general partner interest. AAP s ownership of both of these interests entitles it to receive, without duplication:

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

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

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

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

Such amounts do not take into account temporary and permanent reductions in IDR payments that are currently in place in connection with past PAA acquisition activities, PAA s January 2016 preferred unit offering, or any reductions that may be implemented with respect to future activities. The cash distributions AAP receives from PAA are tied to (i) PAA s per unit distribution level, (ii) the number of PAA common units outstanding and (iii) the number of PAA preferred units outstanding. An increase in either factor (assuming the other factor remains constant or increases) will generally, absent additional IDR reductions, result in an increase in the amount of cash distributions AAP receives from PAA, a portion of which we, in turn, receive from AAP. Because the IDRs currently participate at the maximum percentage participation rate, any future growth in distributions we receive from AAP will not result from an increase in the percentage participation rate associated with the IDRs.

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

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PAA s Business Strategy

PAA s principal business strategy is to provide competitive and efficient midstream transportation, terminalling, storage, processing, fractionation and supply and logistics services to producers, refiners and other customers. Toward this end, PAA endeavors to address regional supply and demand imbalances for crude oil and NGL in the United States and Canada by combining the strategic location and capabilities of its transportation, terminalling, storage, processing and fractionation assets with its extensive supply, logistics and distribution expertise. 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:

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

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

- developing and implementing 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 balance that typically provides PAA with the opportunity to generate a base level of margin in a variety of market conditions (subject to the effects of seasonality). In certain circumstances, PAA may be able to realize incremental margins during volatile market conditions.

- *PAA has the evaluation, integration and engineering skill sets and the financial flexibility to continue to pursue acquisition and expansion opportunities.* Since 1998, PAA has completed and integrated over 85 acquisitions with an aggregate purchase price of approximately $11.7 billion. PAA has also implemented expansion capital projects totaling approximately $10 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, 2015, PAA had approximately $2.3 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 industry experience, and an average of 18 years with PAA or its predecessors and affiliates. In addition, through their ownership of common units, indirect interests in PAA s general

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partner, grants of phantom 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. Because our only cash-generating assets consist of our partnership interests in AAP, which currently derives all of its cash flows from PAA s distributions, we intend to maintain a level of indebtedness at AAP such that it will not be material in relation to PAA s adjusted EBITDA or other financial metrics used in the evaluation of its business. As of December 31, 2015, AAP had $559 million of debt outstanding under its credit facility. In connection with future PAA equity issuances, we expect AAP may fund any capital contribution required to maintain its indirect 2% general partner interest in PAA with credit facility borrowings. We do not anticipate that additional debt associated with these contributions will be material to our consolidated financial position, as such equity issuances are typically used to pay down existing debt or fund PAA s growth through acquisitions or organic growth opportunities. We would expect to fund direct acquisitions made by us, if any, with a combination of debt and equity.

PAA s Financial Strategy

Targeted Credit Profile

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

- an average long-term debt-to-total capitalization ratio of approximately 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, equity-indexed compensation plan charges, certain gains and losses from derivative activities and other selected items that impact comparability);
- 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.

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. During the latter part of 2015, energy industry conditions deteriorated and capital markets access for energy companies was disrupted, which has continued into 2016. To fund PAA s ongoing capital program and maintain a solid capital structure and significant liquidity, in January 2016, PAA raised $1.6 billion of equity capital through the sale of approximately 61.0 million unregistered Series A Convertible Preferred Units. See Note 10 to our Consolidated Financial Statements for additional information. 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 PAA funding its 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 the industry recovers and PAA realizes EBITDA growth from capital investments.

PAA s Acquisitions

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

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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)
50% Interest in BridgeTex Pipeline Company, LLC (BridgeTex)	Nov-2014	BridgeTex owns a crude oil pipeline that extends from Colorado City, Texas to East Houston	$	1,088(3)
US Development Group 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(4)
Western Refining, Inc. Pipeline and Storage Assets	Dec-2011	Multi-product storage facility in Virginia and Crude oil pipeline in southeastern New Mexico	$	220(5)
Velocity South Texas Gathering, LLC	Nov-2011	Crude oil and condensate gathering and transportation assets in South Texas	$	349
SG Resources Mississippi, LLC	Feb-2011	Southern Pines Energy Center natural gas storage facility	$	765(6)
Nexen Holdings U.S.A. Inc. Gathering and Transportation Assets	Dec-2010	Crude oil gathering business and transportation assets in North Dakota and Montana	$	229(7)

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

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

(3) 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.

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

(5) Includes both transactions with Western.

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

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

Ongoing Acquisition and Investment Activities

Consistent with its business strategy, PAA is continuously engaged in the evaluation of potential acquisitions, joint ventures and capital projects. As a part of these efforts, PAA often engages in discussions with potential sellers or other parties regarding the possible purchase of or investment in assets and operations that are strategic and complementary to PAA s existing operations. 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. These acquisition and investment efforts often involve assets which, if acquired or constructed, could have a material effect on PAA s financial condition and results of operations.

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From time to time, PAA may also sell assets that it regards as non-core or that it believes might be a better fit with the business and/or assets of a third-party buyer.

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 believes that the diversity and balance of its expansion capital project portfolio (i.e., relatively large number of projects that are small to medium sized and spread across multiple geographic regions) reduces its overall exposure to cost overruns, timing delays and other adverse market developments with respect to a particular project or region. PAA s 2016 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 2016 capital plan as of February 2016:

Basin/Region	Project	2016 Plan Amount (1) ($ in millions)	Description	Projected In-Service Date
Permian	Permian Basin Area Pipeline Projects	$ 185	Multiple projects to increase and expand PAA s pipeline infrastructure in the Delaware Basin	2016
	Cactus Pipeline	20	Installation of two separate valves and pump stations to add 80,000 Bbls/d of additional capacity (increases pipeline capacity to 330,000 Bbls/d)	2016
Eagle Ford	Eagle Ford JV Project	20	50% interest in new, 1.2 million barrel terminal in Corpus Christi, TX capable of loading ocean going vessels at a rate of 20,000 barrels per hour	2018
Central / Mid-Continent	Diamond Pipeline	260	50% interest in 440 miles of new crude oil pipeline; 200,000 Bbls/d capacity from Cushing, OK to Valero s refinery in Memphis, TN	2017
	Red River Pipeline (Cushing to Longview)	290	Approximately 400 miles of new crude oil pipeline; 150,000 Bbls/d capacity from Cushing, OK to Longview, TX	2016
	Cushing Terminal Expansions	35	Addition of 1.6 million barrels of storage capacity	2016

	Caddo Pipeline	30	50% interest in 80 miles of new 12-inch crude oil pipeline; 80,000 Bbls/d capacity between Longview, TX and Shreveport, LA	2016
Rocky Mountain	Saddlehorn Pipeline	155	40% of Saddlehorn s 190,000 Bbls/d of capacity in the 600 miles of new 20-inch crude oil undivided joint interest pipeline from the DJ Basin to Cushing, OK	2016

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Basin/Region	Project	2016 Plan Amount (1) ($ in millions)		Description	Projected In-Service Date
Gulf Coast	St. James Terminal Expansions		35	Addition of 1.5 million barrels of storage capacity with connectivity to the rail and dock facilities	2016
Canada	Fort Saskatchewan Facility Projects		190	Multi-phase project, Phase I of which includes (i) development of two new high rate delivery caverns, (ii) conversion of service of two existing caverns, (iii) the addition of 2.4 million barrels of brine capacity and (iv) development of a truck loading facility Phase II includes (i) expanding inlet fractionation capacity by 20,000 Bbls/d, (ii) development of two new ethane caverns and a utility cavern, (iii) the addition of 2.7 million barrels of brine capacity and (iv) development of a propane rail loading facility	Various, throughout 2016 and 2017
Other	Other Projects		280		
		$	1,500		

(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 8.1 million barrels per day. However, in 2014, global production growth outpaced global consumption growth by 1.1 million barrels per day, with non-OPEC accounting for 104% of the production growth. In 2015, the markets remained oversupplied due to the continuation of the 2014 imbalance. Supply growth in 2015 outpaced demand growth by another 1.0 million barrels per day, resulting in an imbalance of 1.9 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 2016 (see EIA website at *www.eia.doe.gov*):

	Annual Liquids Production (1)				Δ from 2004	Δ from 2013	Δ from 2014
	2004	2013	2014	2015	2013	2014	2015
	(in millions of barrels per day)						
Production (Supply)							
OPEC	33.6	37.3	37.2	38.3	3.7	(0.1)	1.1
Non-OPEC	49.8	53.7	56.1	57.4	3.9	2.4	1.3
Total	83.4	91.0	93.3	95.7	7.6	2.3	2.4

Total Consumption (Demand)	83.1	91.2	92.4	93.8	8.1	1.2	1.4
Global Supply / Demand Balance	0.3	(0.2)	0.9	1.9	(0.5)	1.1	1.0

(1) Amounts are derived from the EIA s Short-Term Energy Outlook.

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This surge in liquids production without a commensurate increase in demand has led to a near-to-medium-term supply imbalance, which has resulted in a reduction to benchmark petroleum prices. Producers, in turn, are scaling back capital programs, which will ultimately reduce supply. This is expected to lead to underinvestment in long lead time projects and 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.

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 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 Bakken Shale in North Dakota. As a result, North American crude oil production increased 3.6 million barrels per day, or 32%, between 2011 and 2014, with the increases coming primarily from Canada, the Eagle Ford Shale, the Permian Basin and the Bakken Shale. 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, Midcontinent and Denver Julesburg basins.

However, in the latter half of 2014 crude oil prices fell approximately 50%, and then approximately another 30% during 2015. The reduction in prices precipitated a significant slowdown in drilling activity and plans as producers right-sized their capital budgets to the significantly reduced levels of cash flow resulting from lower prices, a process that is continuing into 2016. The combination of the slowdown of growth in U.S. crude oil production caused by declining prices and the significant commitments for new infrastructure created an environment in which margins have compressed and differentials are less than transportation costs in some cases.

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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. Since reaching a multi-year low in 2009, U.S. net refinery inputs of crude oil have increased to 16.2 million barrels per day in 2015. From 2009 through 2014, 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 1985-2007. In 2015, U.S. refinery inputs reached historically high levels fueled by price driven demand growth and exports. U.S. petroleum consumption increased to 19.5 million barrels per day for the twelve month period ended October 2015, the highest levels since 2008. The table below shows the overall domestic petroleum consumption projected through 2017 and is derived from the EIA Short-Term Energy Outlook, January 2016 (see EIA website at *www.eia.doe.gov*).

	Actual	**Projected**	
	2015	**2016**	**2017**
	(In millions of barrels per day)		
Supply			
Domestic Crude Oil Production	9.4	8.7	8.5
Net Imports - Crude Oil	6.9	7.2	7.6
Other (Supply Adjustment/Stock Change)	(0.1)	0.3	0.2
Crude Oil Input to Domestic Refineries	16.2	16.2	16.3
Net Product Imports / (Exports)	(2.2)	(2.6)	(2.7)
Supply from Renewable Sources	1.1	1.1	1.1
Other - (NGL Production, Refinery Processing Gain)	4.4	4.8	5.1
Total Domestic Petroleum Consumption	19.5	19.5	19.8

U.S. Crude Oil Exports

At the end of 2015, the U.S. Congress agreed to lift the 40-year ban on exporting U.S. crude oil, providing domestic oil producers the ability to sell into the international market. The immediate impact will most likely not be felt in 2016 as refineries have increased their processing of U.S. crude oil while domestic production output is expected to decline.

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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.

- *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 80%) of the United States NGL supply comes from gas processing plants, which separate a mixture of NGL from the dry gas (primarily methane). The NGL mix (also referred to as Y Grade) is then either fractionated at the processing site into the five individual NGL components (known as purity products), which may be transported, stored and sold to end use markets or transported as a Y-Grade to a regional fractionation facility.

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

NGL products from refineries represent approximately 17% 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 3% 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 the production points and the delivery points, cost-efficiency and the quantity of product being transported. Pipelines are generally the most cost-efficient mode of transportation when large, consistent volumes of product are to be delivered.

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

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

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

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

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

- the absolute prices of NGL products and their prices relative to natural gas and crude oil;
- drilling activity and wet natural gas production in developing liquids-rich production areas;
- available processing, fractionation, storage and transportation capacity;
- petro-chemical demand;
- 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, (iii) increased availability of storage capacity and (iv) 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) construction of new gas-fired power plants, (iii) sustained fuel switching from coal to natural gas among existing power plants and (iv) growth in base-level industrial demand. As a result, we remain optimistic about the intermediate- to long-term intrinsic value of our natural gas storage assets.

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

Description of Segments and Associated Assets

Under GAAP, we consolidate AAP and PAA and its subsidiaries. We currently have no separate operating activities apart from those conducted by PAA. As such, our segment analysis, presentation and discussion is the same as that of PAA, which conducts its operations through three segments Transportation, Facilities and Supply and Logistics. Accordingly, any references to we, our, and similar terms describing assets, business characteristics or other related matters are references to assets, business characteristics or other matters involving PAA s assets and operations. We have an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. The map below highlights our more significant assets (including certain assets under construction or development) as of December 31, 2015:

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

Transportation Segment

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

As of December 31, 2015, 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:

- 18,100 miles of active crude oil and NGL pipelines and gathering systems;
- 30 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;
- 830 trailers (primarily in Canada); and
- 142 transport and storage barges and 64 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, 2015, grouped by geographic location:

Region / Pipeline and Gathering Systems (1)	Miles	2015 Average Net Barrels per Day (2) (in thousands)
United States Crude Oil Pipelines		
Permian Basin		
Basin / Mesa / Sunrise	696	829
BridgeTex (3) (4)	408	103
Cactus	298	76
Permian Basin Area Systems	2,787	841

Permian Basin Subtotal	4,189	1,849
South Texas/Eagle Ford		
Eagle Ford Area Systems (4)	670	306
South Texas/Eagle Ford Subtotal	670	306
Western		
All American (5)	138	14
Line 63 / Line 2000	314	120
Other	121	81
Western Subtotal	573	215
Rocky Mountain		
Bakken Area Systems (4)	1,017	142
Salt Lake City Area Systems (4)	969	143
White Cliffs (3) (4)	1,054	43
Other	1,296	112
Rocky Mountain Subtotal	4,336	440
Gulf Coast		
Capline (3)	631	170
Pascagoula	41	110
Other	868	252
Gulf Coast Subtotal	1,540	532
Central		
Mid-Continent Area Systems	2,419	337
Other	137	76
Central Subtotal	2,556	413
United States Total	**13,864**	**3,755**
Canada		
Crude Oil Pipelines		
Manito	556	47
Rainbow	827	112
Rangeland	1,171	59
South Saskatchewan	346	61
Other	197	113
Crude Oil Pipelines Subtotal	3,097	392
NGL Pipelines		
Co-Ed	633	57
Other	550	136
NGL Pipelines Subtotal	1,183	193
Canada Total	**4,280**	**585**
Grand Total	**18,144**	**4,340**

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(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.

United States Pipelines

Permian Basin

Basin Pipeline. We own an 87% undivided joint interest in and are the operator of Basin Pipeline. Basin Pipeline is a primary route for transporting crude oil from the Permian Basin (in west Texas and southern New Mexico) to Cushing, Oklahoma, for further delivery to Mid-Continent and Midwest refining centers. 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.

Basin Pipeline is an approximate 530-mile mainline, telescoping crude oil pipeline with a capacity ranging from approximately 240,000 barrels per day to 450,000 barrels per day (approximately 208,800 barrels per day to 392,000 barrels per day attributable to our interest), depending on the segment. The pipeline also includes approximately 6 million barrels of storage tankage.

In 2015, we placed into service a 24-inch pipeline loop of Basin Pipeline from Wink to Midland. In addition, we placed into service Phase I of the new Wink South terminal which will handle crude oil from the Delaware Basin and New Mexico, and expect that Phase II of the project will be in service in the second half of 2016. The completion of these projects along with reactivation of a 20-inch pipeline from Wink to Midland during the first half of 2016 will provide 550,000 barrels per day of capacity from Wink to Midland.

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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, which extends from Midland to connecting carriers at Colorado City. The 84-mile Sunrise Pipeline was placed in service in December 2014, with a capacity of 250,000 barrels per day.

BridgeTex Pipeline. We own a 50% interest in BridgeTex, which is the entity that owns the BridgeTex Pipeline, a 20-inch crude oil pipeline with a capacity of 300,000 barrels per day that extends from Colorado City to East Houston. At Colorado City, the BridgeTex Pipeline is connected to our Basin and Sunrise pipelines. Magellan Midstream Partners, L.P. (MMP) owns the remaining 50% interest and serves as the operator of the BridgeTex Pipeline. BridgeTex has entered into a long-term capacity lease agreement with MMP whereby its shippers will have access to capacity on MMP s pipeline from Houston to Texas City.

Cactus Pipeline. We own and operate the Cactus Pipeline, a 298-mile crude oil pipeline extending from McCamey to Gardendale, Texas. The Cactus Pipeline provides 250,000 barrels per day of takeaway capacity from the Permian Basin, and will be expanded to approximately 330,000 barrels per day when additional pumping equipment is added in 2016.

Permian Basin Area Systems. We operate wholly owned systems of 2,787 miles that aggregate receipts from wellhead gathering lines and bulk truck injection locations into a combination of 4- to 16-inch diameter trunk lines for transportation and delivery into the Basin Pipeline at Jal, Wink and Midland as well as our terminal facilities in Midland. During 2015, we completed construction of several projects, including the Triple Crown gathering system, the Avalon, Texas 12-inch extension to the Triple Crown gathering system, the 20-inch loop of our pipeline from Blacktip to Wink, the 16-inch Wolfbone Ranch pipeline from south Reeves County, Texas to Wink and several gathering projects in Texas s Upton and Reagan counties.

South Texas/Eagle Ford Area

Eagle Ford Area Systems. We own a 100% interest in and are the operator of several gathering systems that feed into our Gardendale Station, and we also own a 50% interest in Eagle Ford Pipeline, which is the entity that owns the Eagle Ford joint venture pipeline. 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 Systems consist of 670 miles of pipeline that service production in the Eagle Ford shale play of South Texas and include approximately 5 million barrels of operational storage capacity across the system (including the capacity added in 2015, as discussed below). The systems 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 Enterprise s connection at Lyssy in Wilson County, Texas.

In 2015, several projects to expand and extend the Eagle Ford joint venture pipeline were completed. Such projects included (i) completion of a connection to our Cactus Pipeline, (ii) completion of a 20-inch pipeline loop of the entire pipeline, as well as expanded pumping capabilities at Three Rivers and (iii) construction of an additional 3 million barrels of operational storage capacity across the system. Combined, these projects increased capacity of the Eagle Ford joint venture pipeline to approximately 600,000 barrels per day. In addition, Eagle Ford Pipeline completed construction of a new condensate gathering system with a capacity of up to 100,000 barrels per day that extends from our station at Three Rivers into Karnes County and Live Oak County.

Western

All American Pipeline. We own and operate 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. See Note 16 to our Consolidated Financial Statements for additional information regarding this incident.

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Line 63. We own and operate the Line 63 pipeline that transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield, California. The pipeline is also connected to our crude oil rail terminal at Bakersfield. The Line 63 pipeline consists of a 107-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 pipeline includes 33 miles of distribution pipelines in the Los Angeles Basin, with a throughput capacity of approximately 20,000 barrels per day, and approximately 117 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 2009, a 71-mile segment of Line 63 was temporarily taken out of service to allow for certain repairs and realignments to be performed. Line 63 volumes are currently being redirected from the north end of this out-of-service segment to the parallel Line 2000. The product is then batched along Line 2000 until it is re-injected into the active portion of Line 63, which is south of the out-of-service segment, for subsequent delivery to customers. We have commenced a project to place this idle segment in service, which we expect to complete in 2016.

Line 2000. We own and operate the Line 2000 crude oil pipeline that originates at our Emidio Pump Station (part of the All American Pipeline) 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 Systems. We own and operate several gathering systems and pipelines that service crude oil production in Eastern Montana and Western North Dakota, and we also own a 22% interest in Butte, which is the entity that owns the Butte Pipeline, a 16-inch crude oil pipeline system extending from Baker, Montana to Guernsey, Wyoming.

Salt Lake City Area Systems. 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 is the entity that owns the Frontier Pipeline. These 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 970 miles and approximately one million barrels of storage capacity. These pipelines have a maximum throughput capacity of (i) approximately 20,500 barrels per day from Wamsutter, Wyoming to Ft. Laramie, (ii) approximately 47,000 barrels per day from Wamsutter to Wahsatch, Utah, (iii) approximately 95,000 barrels per day from Wahsatch to Salt Lake City and (iv) approximately 75,000 barrels per day from Casper to Ranch Station, Utah.

White Cliffs Pipeline. We own an approximate 36% interest in White Cliffs, the entity that owns the White Cliffs Pipeline, which consists of two 527-mile, 12-inch, crude oil pipelines that move crude out of the DJ Basin to the Cushing, Oklahoma market. Rose Rock Midstream, L.P. serves as the operator of the pipeline, which originates in Platteville, Colorado and terminates in Cushing. In late 2015, the addition of two pump stations increased capacity on the pipeline to approximately 215,000 barrels per day.

Cowboy Pipeline. We recently constructed the Cowboy Pipeline, a 12-inch, 27-mile pipeline that provides 75,000 barrels per day of light sweet crude oil capacity from Cheyenne, Wyoming to our rail loading facility near Carr, Colorado and will be connected to the Saddlehorn Pipeline when it is placed in service. The Cowboy Pipeline includes a new terminal at Cheyenne with approximately 600,000 barrels of storage tank capacity. The Cowboy Pipeline will enable us to source crude oil from our and third party pipeline systems that feed the Guernsey market, through connection to our Cheyenne Pipeline, and deliver to Cushing through connection to the Saddlehorn Pipeline.

Saddlehorn Pipeline. We own a 40% interest in Saddlehorn, which is currently developing the Saddlehorn Pipeline, a 20-inch pipeline that will extend from various receipt points in the Niobrara and DJ Basin to Cushing. The Saddlehorn Pipeline is a joint venture in which Saddlehorn owns an undivided 62.5% interest in the pipeline; Grand Mesa Pipeline, LLC owns the remaining 37.5% interest. Saddlehorn will own 190,000 barrels per day of the capacity in Saddlehorn Pipeline and will have one million barrels of storage capacity at both Platteville and Cushing. The Platteville-to-Cushing segment of the pipeline is expected to be operational in mid-2016 and the Platteville-to-Carr segment is anticipated to be operational by the end of 2016. 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. MMP serves as construction manager and operator of the pipeline.

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 of the pipeline. Capline has direct connections to a significant amount of crude oil production in the Gulf of Mexico. In addition, it has two active docks capable of handling approximately 600,000-barrel tankers and is connected to the Louisiana Offshore Oil Port and our St. James terminal and transports various grades of crude oil to PADD II. Total designed operating capacity is approximately 1.1 million barrels per day of crude oil, of which our attributable interest is approximately 600,000 barrels per day.

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 pipeline.

Central

Mid-Continent Area Systems. We own and operate pipeline systems that source crude oil from Western and Central Oklahoma, Southwest Kansas and the Eastern Texas Panhandle. These systems consist of approximately 2,420 miles of pipeline with transportation and delivery into and out of our terminal facilities at Cushing, Oklahoma. In addition, in early 2015 we completed construction of a new receipt facility on the Basin Pipeline in southern Oklahoma to aggregate South Central Oklahoma Oil Province (SCOOP) production.

Diamond Pipeline. We own a 50% interest in Diamond, which is currently developing the Diamond Pipeline, a 20-inch, 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 project is underpinned by a long-term shipper agreement with Valero and a related contract for storage and terminalling services at our Cushing terminal. In December 2015, Valero exercised its option to become a partner in Diamond and owns the remaining 50% interest. We will serve as operator of the Diamond Pipeline, which is expected to be completed in 2017.

Red River Pipeline (Cushing to Longview). We are currently developing and constructing the Red River Pipeline, which will be a 16-inch crude oil pipeline with an initial takeaway capacity of 150,000 barrels per day extending from Cushing to Longview. The Red River Pipeline is supported by long-term shipper commitments and is expected to be completed in late 2016.

Caddo Pipeline. We own a 50% interest in Caddo, which is constructing the Caddo Pipeline. The Caddo Pipeline is an 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 refineries in the Shreveport, Louisiana area, as well as to an El Dorado, Arkansas refinery through a connection to Delek Logistics Partners, LP s (Delek) pipeline. Delek owns the remaining 50% interest in Caddo. We will serve as operator of the Caddo Pipeline, which is expected to be completed in late 2016.

Canada Pipelines

Crude Oil Pipelines

Manito Pipeline. We own a 100% interest in the Manito heavy oil system. This 556-mile system is comprised of the Manito Pipeline, the North Saskatchewan (North Sask) pipeline and the Bodo/Cactus Lake pipeline. Each system consists of a blended crude oil line and a parallel diluent line that delivers condensate to upstream blending locations. The North Sask pipeline is 84 miles in length and originates near Turtleford, Saskatchewan and terminates in Dulwich, Saskatchewan. The Manito Pipeline includes 339 miles of 10-inch blend pipeline. The mainline segment originates at Dulwich and terminates at Kerrobert, Saskatchewan. The Bodo/Cactus Lake pipeline is a 133 mile long, 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 System. We own a 100% interest in the Rainbow system. The Rainbow system is comprised of (i) a 480-mile, 20-inch to 24-inch mainline crude oil pipeline, with 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 159 miles of associated gathering pipelines and (ii) a 188-mile, 10-inch pipeline to transport diluent north from Edmonton to our Nipisi truck terminal in Northern Alberta.

In late 2015, our Indigo pipeline project, which would have connected to our Rainbow system, was canceled as a result of the committed shipper s decision to cancel development of its thermal in situ project located in Alberta, Canada. We have been reimbursed for our costs incurred on this project.

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Rangeland System. We own a 100% interest in the Rangeland system. The Rangeland system consists of a 670 mile, 8-inch to 16-inch mainline pipeline and approximately 500 miles of 3-inch to 8-inch gathering pipelines. The Rangeland system transports NGL mix, butane, condensate, light sweet crude oil and light sour crude oil either north to Edmonton or south to the U.S./Canadian border near Cutbank, Montana, where it connects to our Western Corridor system.

South Saskatchewan System. We own a 100% interest in the South Saskatchewan system. This system consists of a 160 mile, 16-inch mainline from Cantuar to Regina, Saskatchewan and 186 miles of 4-inch to 12-inch gathering pipelines from the Rapdan area to Cantuar. The South Saskatchewan system 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.

NGL Pipelines

Co-Ed NGL Pipeline System. We own and operate the Co-Ed NGL Pipeline system, which consists of approximately 630 miles of 3-inch to 10-inch pipeline. This pipeline system gathers NGL from approximately 35 field gas processing plants located in Alberta, including all of the NGL produced at the Cochrane Straddle Plant. The Co-Ed NGL Pipeline system has throughput capacity of approximately 72,000 barrels per day to our NGL facilities at Fort Saskatchewan.

Facilities Segment

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

Revenues generated in this segment primarily include (i) fees that are generated from storage capacity agreements, (ii) terminal throughput fees that are generated when we receive crude oil, refined products or NGL from one connecting source and deliver the applicable product to another connecting carrier, (iii) loading and unloading fees at our rail terminals, (iv) fees from NGL fractionation and isomerization 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, 2015, 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 25 million barrels of NGL storage capacity;

- approximately 97 Bcf of natural gas storage working capacity;

- approximately 31 Bcf of owned base gas;

- 10 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;

- seven fractionation plants located throughout Canada and the United States with an aggregate net processing capacity of approximately 166,300 barrels per day, and an isomerization and fractionation facility in California with an aggregate processing capacity of approximately 15,000 barrels per day;

- 28 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 with an aggregate load capacity of 107,000 barrels per hour, including vapor recovery rates, and an aggregate unload capacity of 182,000 barrels per hour; and

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

The following is a tabular presentation of our active Facilities segment storage and service assets in the United States and Canada as of December 31, 2015, grouped by product and service type, with capacity and volume as indicated:

Crude Oil and Refined Products Storage Facilities	**Total Capacity (MMBbls)**
Cushing	21
LA Basin	8
Martinez and Richmond	5
Mobile and Ten Mile	5
Patoka	6
St. James	11
Yorktown (1)	5
Other (2)	19
	80

NGL Storage Facilities	**Total Capacity (MMBbls)**
Bumstead	4
Fort Saskatchewan	5
Sarnia Area	9
Tirzah	1
Other	6
	25

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

Natural Gas Processing Facilities (3)	**Ownership Interest**	**Total Gas Inlet Volume (4) (Bcf/d)**	**Net Gas Processing Capacity (5) (Bcf/d)**
United States Gulf Coast Area	100%	0.2	0.6
Canada	36-100%	1.1	5.4
		1.3	6.0

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

NGL Fractionation and Isomerization Facilities	**Ownership Interest**	**Total Spec Product (4) (Bbls/d)**	**Net Capacity (Bbls/d)**

Fort Saskatchewan	21-100%	26,760	51,300
Sarnia	62-84%	60,345	90,000
Shafter	100%	6,520	15,000
Other	82-100%	9,775	25,000
		103,400	181,300

Rail Facilities	**Ownership Interest**	**Loading Capacity (5) (Bbls/d)**	**Unloading Capacity (5) (Bbls/d)**
Crude Oil Rail Facilities	50-100%	382,000	350,000

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	Ownership Interest	Number of Rack Spots	Number of Storage Spots
NGL Rail Facilities **(6)**	50-100%	258	1,128

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

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

Since 1999, we have completed multiple expansions that have increased the capacity of the Cushing Terminal to a total of 21 million barrels. In 2015, we added approximately 1.4 million barrels of storage and we expect to add approximately 1.6 million barrels of storage capacity during 2016.

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

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

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

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

St. James Terminal. We have 11 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 2015, we added approximately 1 million barrels of storage capacity to the St. James terminal, and we expect to add approximately 1.5 million barrels of capacity in 2016.

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. We own a 50% interest in Eagle Ford Terminals, which is currently developing a terminal in Corpus Christi, Texas that will be capable of loading ocean going vessels at a rate of 20,000 barrels per hour. Initial storage capacity of the terminal will be 1.2 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. Enterprise owns the remaining 50% interest in Eagle Ford Terminals.

NGL Storage Facilities

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

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

During 2013, we began upgrading our Fort Saskatchewan storage capacity as part of a multi-phase expansion. The first phase of the expansion will add two new NGL storage caverns each with a capacity of 350,000 barrels and will convert approximately 2.4 million barrels of existing NGL mix storage capacity to propane and condensate storage supported by the addition of approximately 2.4 million barrels of new brine pond capacity. Additionally, as part of the first phase of the project, we expanded our propane truck loading capabilities and added new butane truck loading, which came in service in early 2015. The second phase of the project will see the development of 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 facility consists 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, 4 multi-product truck loading racks and a network of 14 pipelines providing product delivery capabilities to our Windsor, St. Clair and Green Springs terminal facilities, in addition to refineries, chemical plants and other pipeline systems in the area. The facility has approximately 4 million barrels of useable storage capacity. In 2012, we initiated a brine disposal program that will 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 is expected to increase capacity by as much as 3 million barrels when completed.

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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. In 2014, we initiated a brine disposal program that will facilitate the removal of excess brine via pipeline from our Windsor storage terminal. The project is expected to increase useable NGL storage capacity at the facility by approximately 1 million barrels.

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

Tirzah. The Tirzah facility is located in South Carolina and consists of an underground granite storage cavern with approximately 1 million barrels of useable capacity. The Tirzah facility is connected to the Dixie Pipeline System (a third-party system) via our 63-mile pipeline.

Natural Gas Storage Facilities

We own three FERC regulated natural gas storage facilities located in the Gulf Coast and Midwest that are permitted for 149 Bcf of working gas capacity, and as of December 31, 2015, we had an aggregate working gas capacity of approximately 97 Bcf in service. Our facilities have aggregate peak daily injection and withdrawal rates of 4.1 Bcf and 6.4 Bcf, respectively.

Our natural gas storage facilities are strategically located and have a diverse group of customers, including utilities, pipelines, producers, power generators, marketers and liquefied natural gas (LNG) exporters, whose storage needs vary from traditional seasonal storage services to hourly balancing. We are located near several major market hubs, including the Henry Hub (the delivery point for NYMEX natural gas futures contracts), the Carthage Hub (located in East Texas), the Perryville Hub (located in North Louisiana), and the major market hubs of Chicago, Illinois and Dawn, Ontario. Our facilities 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.

Natural Gas Processing Facilities

We own and/or operate four straddle plants and two field gas processing plants located in Western Canada with an aggregate net natural gas processing capacity of approximately 5.4 Bcf per day and long-term liquid supply contracts relating to a third-party owned straddle plant with gross processing capacity of approximately 2.5 Bcf per day. We also own and operate four natural gas processing plants located in Louisiana and Alabama with an aggregate natural gas processing capacity of approximately 0.6 Bcf per day.

NGL Fractionation and Isomerization Facilities

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

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

We recently approved a project to expand our fractionation capacity to provide producers with additional fractionation infrastructure necessary to develop the significant liquids-rich natural gas reserves in western Canada. Upon our target completion date in mid-2017, this expansion will increase capacity to produce a combination of spec NGL products and NGL mix by 20,000 barrels per day. This project is supported by long-term commitments from third parties.

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%.

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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.

During 2015, we commissioned an approximate 40-mile NGL pipeline system capable of delivering up to 10,000 barrels per day from California Resources Corporation s Elk Hills Gas plant to our Shafter facility, increased our storage capacity by 30,000 barrels and added 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 and is adjacent to our Gardendale terminal and rail facility. We completed an expansion of the facility in the second half of 2015, bringing the total processing capacity of the facility to 120,000 barrels per day. The facility has useable storage capacity of 160,000 barrels. In 2015, we also placed in service a ten mile pipeline that connects to a third party pipeline delivering NGL to Mont Belvieu. Throughput at the Gardendale processing facility is supplied by long-term commitments from producers.

Rail Facilities

Crude Oil Rail Loading Facilities

We own seven active crude oil and condensate rail loading terminals, six of which service production in the Niobrara, Eagle Ford, Permian Basin and Bakken shale formations and have a combined loading capacity of approximately 322,000 barrels per day. These facilities are located in Carr, Colorado; Tampa, Colorado; Gardendale, Texas; McCamey, Texas; Manitou, North Dakota; and Van Hook, North Dakota. Our rail terminal in Western Canada near Kerrobert, Saskatchewan was placed in service in the fourth quarter of 2015, with an initial capacity of approximately 60,000 barrels per day.

Crude Oil Rail Unloading Facilities

We own three active crude oil rail unloading terminals that have a combined unloading capacity of approximately 350,000 barrels per day. Our terminal at St. James, Louisiana is connected to our rail unloading facility that has an unload capacity of 140,000 barrels of sweet crude oil per day. In late 2015, we commissioned a project to enhance our St. James rail facility with capability to receive heavy crude oil. 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

We own 21 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 258 railcar rack spots and 1,128 railcar storage spots and we have the ability to switch our own railcars at six of these terminals.

We have approved a number of expansion projects at our Fort Saskatchewan facility, including a 60 car per day propane rail loading facility, which we plan to place in service in 2016.

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;

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

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

In addition to hedged working inventories associated with its merchant activities, as of December 31, 2015, our Supply and Logistics segment also owned significant volumes of crude oil and NGL classified as long-term assets and linefill or minimum inventory requirements and employed a variety of owned or leased physical assets throughout the United States and Canada, including approximately:

- 13 million barrels of crude oil and NGL linefill in pipelines owned by us;
- 5 million barrels of crude oil and NGL linefill in pipelines owned by third parties and other long-term inventory;
- 990 trucks and 1,100 trailers; and
- 10,100 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 sales are based on posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates. However, certain terminalling and storage rates recognized within our Facilities segment are discounted to our Supply and Logistics segment to reflect the fact that these services may be canceled on short notice to enable the Facilities segment to provide services to third parties, generally under longer term arrangements.

The following table shows the average daily volume of our supply and logistics activities for the year ended December 31, 2015:

	Volumes (MBbls/d)
Crude oil lease gathering purchases	943
NGL sales	223
Waterborne cargos	2
Supply and Logistics activities total	1,168

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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 ten 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. In addition, from time to time, we purchase foreign crude oil. Under these contracts we may purchase crude oil upon delivery in the United States or we may purchase crude oil in foreign locations and transport it on third-party tankers. 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 firm up capacity utilization and base-load expansion projects. We utilize our trucking fleet and pipeline network, as well as leased railcars, third-party tank trucks and third-party pipelines to transport NGL.

In addition to purchasing crude oil from producers, we purchase both domestic and foreign crude oil in bulk at major pipeline terminal locations, rail facilities and barge facilities. We also purchase NGL in bulk at major pipeline terminal points and storage facilities from major integrated oil companies, large independent producers or other NGL marketing companies or processors. Crude oil and NGL are purchased in bulk when we believe additional opportunities exist to realize margins further downstream in the crude oil or NGL distribution chain. The opportunities to earn additional margins vary over time with changing market conditions. Accordingly, the margins associated with our bulk purchases will fluctuate from period to period.

Crude Oil and NGL Sales. The activities involved in the supply, logistics and distribution of crude oil and NGL are complex and require current detailed knowledge of crude oil and NGL sources and end markets, as well as a familiarity with a number of factors including grades of crude oil, individual refinery demand for specific grades of crude oil, area market price structures, location of customers, various modes and availability of transportation facilities and timing and costs (including storage) involved in delivering crude oil and NGL to the appropriate customer.

We sell our crude oil to major integrated oil companies, independent refiners and other resellers in various types of sale and exchange transactions. Our crude oil sales contracts generally range in term from thirty-day evergreen to five years, with the majority ranging from thirty days to one year and a limited number of contracts extending up to seven years. We sell NGL primarily to propane and refined product retailers, petrochemical companies and refiners, and limited volumes to other marketers. A majority of our NGL contracts generally range in term from a thirty-day evergreen to one year. With the move to longer term (greater than one year) NGL supply contracts, longer term NGL sale contracts are also becoming more commonplace, usually with flexible pricing mechanisms to ensure the sale remains market-based for both the buyer and seller. We establish a margin for the crude oil and NGL we purchase by entering into physical sales contracts with third parties, or by entering into a future delivery obligation with respect to futures contracts on the NYMEX, ICE or over-the-counter exchanges. Through these transactions, we seek to maintain a position that is substantially balanced between purchases and sales and future delivery obligations. From time to time, we enter into various types of sale and exchange transactions including fixed price delivery contracts, collars, financial swaps and crude oil and NGL-related futures contracts as hedging devices.

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

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

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

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

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

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

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

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

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

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

Crude oil, NGL, natural gas and refined products commodity prices have historically been very volatile. For example, since the mid-1980s, NYMEX West Texas Intermediate (WTI) crude oil benchmark prices have ranged from a low of approximately $10 per barrel during 1986 to a high of over $147 per barrel during 2008. During 2015, West Texas Intermediate crude oil prices traded within a range of approximately $35 to $61 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 39% of the WTI benchmark price for crude oil in 2015 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 52% of the WTI benchmark price for crude oil in 2015 to a high of approximately 93% of the WTI benchmark price for crude oil in 2000.

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

Base level segment profit from our supply and logistics activities is dependent on our ability to sell crude oil and NGL at prices in excess of our aggregate cost. Although segment profit may be adversely affected during certain transitional periods 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. In recent periods, 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. While recent market conditions have been challenging, we believe the complementary, balanced nature of our business activities and diversification of our asset base among varying regions and demand-driven and supply-driven markets provides us with 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 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.

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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 18 to our Consolidated Financial Statements.

Customers

Marathon Petroleum Corporation and its subsidiaries accounted for approximately 17%, 17% and 15% of our revenues for the years ended December 31, 2015, 2014 and 2013, respectively. ExxonMobil Corporation and its subsidiaries accounted for approximately 13%, 15% and 13% of our revenues for the years ended December 31, 2015, 2014 and 2013, respectively. Phillips 66 and its subsidiaries accounted for approximately 11% of our revenues for the year ended December 31, 2013. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2015, 2014 and 2013. The majority of revenues from these customers pertain to our supply and logistics operations. The sales to these customers occur at multiple locations and we believe that the loss of these customers would have only a short-term impact on our operating results. There is risk, however, that we would not be able to identify and access a replacement market at comparable margins. For a discussion of customers and industry concentration risk, see Note 13 to our Consolidated Financial Statements.

Competition

Competition among pipelines is based primarily on transportation charges, access to producing areas and supply regions and demand for 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), make it unlikely that new competing pipeline systems comparable in size and scope to our pipeline systems (and excluding those already publicly announced to be under development or construction) will be built in the foreseeable future. However, to the extent there are already third-party owned pipelines or owners with joint venture pipelines with excess capacity in the vicinity of our operations, we are exposed to significant competition based on the relatively low cost of moving an incremental barrel of crude oil or NGL. In 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 have and are purchasing barrels in the market and shipping them on the applicable third party pipeline in satisfaction of their 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 companies, other NGL processing and fractionation companies, the major integrated oil companies, their marketing affiliates and independent gatherers, banks that have established a trading platform, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources greater than ours.

With respect to our natural gas storage operations, the principal elements of competition are rates, terms of service, supply and market access and flexibility of service. An increase in competition in our markets could arise from new ventures or expanded operations from existing competitors. Our natural gas storage facilities compete with several other storage providers, including regional storage facilities and utilities. Certain pipeline companies have existing storage facilities connected to their systems that compete with some of our facilities.

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Regulation

Our assets, operations and business activities are subject to extensive legal requirements and regulations under the jurisdiction of numerous federal, state, provincial and local agencies. Many of these agencies are authorized by statute to issue, and have issued, requirements binding on the pipeline industry, related businesses and individual participants. The failure to comply with such legal requirements and regulations can result in substantial 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 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. In 2010 we settled by means of separate Consent Decrees, two Department of Justice (DOJ)/Environmental Protection Agency (EPA) proceedings regarding certain releases of crude oil. One Consent Decree applied to our crude oil pipelines in general and was terminated in November 2013. The remaining Consent Decree applies to a specific system. Although we believe that all material aspects of the injunctive elements of the remaining Consent Decree (costs and operational effects) have been incorporated into our budgeting and planning process, future proceedings could result in additional injunctive remedies, the effect of which would subject us to operational requirements and constraints.

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.

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United States

The HLPSA was amended by the Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. These amendments have resulted in the adoption of rules by the Department of Transportation (DOT) that require transportation pipeline operators to implement integrity management programs, including frequent inspections, correction of identified anomalies and other measures, to ensure pipeline safety in high consequence areas such as high population areas, areas unusually sensitive to environmental damage, and commercially navigable waterways. In the United States, our costs associated with the inspection, testing and correction of identified anomalies were approximately $107 million in 2015, $107 million in 2014 and $57 million in 2013. Based on currently available information, our preliminary estimate for 2016 is that we will incur approximately $65 million in capital expenditures and approximately $37 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 $33 million in 2015, $21 million in 2014 and $22 million in 2013, and our preliminary estimate for 2016 is that we will incur approximately $30 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 Senate Committee on Commerce, Science & Transportation passed the Securing America s Future Energy: Protecting Infrastructure of Pipelines and Enhancing Safety Act (Safe Pipes Act) on December 9, 2015. This bill would (i) reauthorize PHMSA through fiscal year 2019, (ii) require reports to Congress on the status of rulemaking efforts in the areas of integrity management, leak detection and accident and incident notification and, (iii) require PHMSA to initiate new rulemaking for underground natural gas storage facilities and (iv) require PHMSA to define the Great Lakes as an ecological resource under 49 CFR 195.6 (b). The committee has sent the bill to the Senate for further consideration.

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;
- 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.

A number of the provisions of this NPRM have the potential to cause owners and operators of pipeline facilities to incur significant capital expenditures and/or operating costs. It is not known when, or in what form, this proposed rulemaking will become final. More recently, in February 2016, PHMSA issued an advisory bulletin for natural gas storage facility operators in response to the leak at a third-party gas storage facility in Southern California. PHMSA indicated when it issued the advisory bulletin that additional regulations related to safety standards for natural gas storage facilities are likely forthcoming. At this time, we cannot predict the impact of any future regulatory actions in this area.

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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 approved 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 EPA issues rules on dispersant safety.
- The Pipeline Safety: Inspections Bill 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 requires automatic shut-offs for pipelines located in environmentally sensitive areas.

Efforts are now underway to draft regulations in order to adopt the provisions of the bills by early 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 $33 million, $32 million and $26 million in 2015, 2014 and 2013, respectively. For 2016, we have budgeted approximately $34 million in connection with continued API 653 compliance activities and similar new EPA regulations for tanks not regulated by the DOT. Certain storage tanks may be taken out of service if we believe the cost of compliance will exceed the value of the storage tanks or replacement tankage may be constructed.

Canada

In Canada, the NEB and provincial agencies such as the Alberta Energy Regulator (AER) and the Saskatchewan Ministry of Economy regulate the safety and integrity management of pipelines and storage tanks used for hydrocarbon transmission. We have incurred and will continue to incur costs related to such regulatory requirements.

In June 2015, the Pipeline Safety Act, SC 2015, c. 21 received royal assent. Upon coming into force in June 2016, it will amend 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. Canada will be the first country to introduce absolute liability, irrespective of fault, for all costs and damages resulting from an uncontrolled release of oil, gas or other commodity from a major pipeline (i.e. with transport capacity over 250,000 barrels per day), or otherwise as prescribed by regulation for pipelines with lower capacity, up to $1 billion. In instances involving fault or negligence, liability will continue to be unlimited. 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 more stringent requirements with respect to abandoned pipelines, including an obligation to maintain adequate funds to pay for abandonment costs.

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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 $66 million, $66 million and $90 million in 2015, 2014 and 2013, respectively. Our preliminary estimate for 2016 is approximately $66 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 wastes may be included as hazardous wastes under RCRA, in which event our wastes will be subject to more rigorous and costly disposal requirements, resulting in additional capital expenditures or operating expenses.

Hazardous Substances

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

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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.

Environmental Remediation

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

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

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

Air Emissions

Our United States operations are subject to the United States Clean Air Act (Clean Air Act), comparable state laws and associated state and federal regulations. In October 2015, the U.S. EPA promulgated a revised ambient standard for ozone. While full implementation of the standard may take a number of years, the revised standard could make air permit for sources of volatile organic compounds (such as crude oil tank farms) more difficult to obtain in some areas.

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 or (BACT) to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they emit quantities of GHGs that trigger the requirements of these regulations. 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 2015, the EPA proposed regulations that, if adopted in 2016 as proposed, would require significant reductions in fugitive methane emissions from certain upstream and midstream oil and gas facilities. 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 were purchased in 2015.

On January 1, 2015, the AB32 regulations for the first time cover finished fuel providers and importers. California finished fuels providers (refiners and importers) will be required to purchase GHG emission credits for finished fuel sold in or imported into California. The rules implementing the AB32 program were finalized in December 2011. The compliance requirements of the GHG cap-and-trade program through 2020 are being phased in. 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 will require 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, upon ratification, will require 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.

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Canada

Federal Regulation. Along with 194 other countries, Canada is a signatory to the UNFCCC, and the previously ratified Kyoto Protocol , under which many nations, including Canada, agreed to limit emissions of GHGs. In December 2011, Canada formally withdrew from the Kyoto Protocol and replaced it with the Durban Platform committing it to develop a legally binding agreement to reduce GHG emissions, the terms of which are yet to be defined, but are to become effective in 2020.

Since 2004, companies emitting more than 100 thousand tons per year (kt/y) of CO_2 equivalent (CO_2e) were required to report their GHG emissions under the Greenhouse Gas Emissions Reporting Program. In 2010, this reporting threshold was reduced to 50 kt/y. Two PMC facilities meet this reporting threshold. In May 2015, the federal government announced plans to reduce its GHG emissions by 30% below 2005 levels by 2030, and formally submitted the plan to the UNFCCC.

Provincial Regulation. In 2014, Alberta introduced the Climate Change and Emissions Management Act, which provides a framework for managing GHG emissions by reducing specified gas emissions, relative to gross domestic product, to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020. The accompanying regulations include the Specified Gas Emitters Regulation (the SGER), which imposes GHG emissions limits, the Specified Gas Reporting Regulation (the SGRR), which imposes GHG emissions reporting requirements, and the Administrative Penalty Regulation which sets out the penalty for non-compliance with the Climate Change and Emissions Management Act.

The SGER expires on December 31, 2017, to ensure it is reviewed for ongoing relevancy and necessity. The regulation applies to facilities in Alberta that have produced 100,000 or more tonnes of GHG emissions per year, and requires reductions in GHG emissions intensity (*i.e.*, the quantity of GHG emissions per unit of production) from emissions intensity baselines. The SGER establishes these emissions intensity baselines. Since the regulation came into effect, PMC has one facility (Fort Saskatchewan Storage and Fractionation Facility) which currently does not meet the reduction obligation. As such, PMC has been required to submit compliance credits which have been completed by submitting payment to the Climate Change Emissions Management Fund (the CCEMC). On June 25, 2015, the Alberta Government announced an amendment to the SGER, which stipulates that the maximum emissions intensity reduction requirement for all facilities will be increased to 15% after January 1, 2016, and then to 20% after January 1, 2017.

Under the SGER, regulated facilities have four ways to comply with the annual emissions intensity reduction requirements: (1) improve emissions intensity at their facilities; (2) purchase Alberta-based offset credits; (3) purchase or use Emission Performance Credits (credits generated by other facilities that have reduced emissions below SGER specifications); or (4) purchase technology offset credits by contributing to Government of Alberta administered CCEMC. Payments into the CCEMC will increase to $20 per tonne of CO_2 over a facility s budget in 2016 and $30 per tonne in 2017, which will increase our operating costs in respect of the Fort Saskatchewan Storage and Fractionation Facility.

In 2015, Alberta s newly elected Government announced the *Specified Gas Emitters Amendment Regulation*, which introduced a fifth way for regulated facilities to meet their net emissions intensity limit the cogeneration compliance adjustment (CCA) for the year which is to be defined in the as of yet unpublished *Standard for Completing Greenhouse Gas Compliance Reports*.

Following the SGER amendments, the Government of Alberta appointed the Climate Change Advisory Panel to review current climate change policies and consult with public, industry, environmental and First Nations groups on climate change strategies. On November 26, 2015, the Government of Alberta released both the panel s Climate Leadership Report to Minister (the Report) and its Climate Leadership Plan (the Plan). The Plan highlights four key strategies to address climate change: (1) completing the phase out of coal-fired sources of electricity by 2030, with cleaner, renewable energy sources in coal s place; (2) replacing the current emissions intensity carbon pricing program with an emissions performance standard; (3) capping oil sands emissions to 100 megatonnes per year with a carbon price for oil sands facilities; and (4) reducing methane emissions by 45% by 2025.

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The Government of Alberta is still developing the details of how the Plan will be implemented, but the Report states that carbon pricing will be central to the new strategy. The Report proposes a Carbon Competitiveness Regulation (CCR) to replace the SGER, under which the carbon price would reach $30 per tonne by 2018. The CCR would also include elements of cap-and-trade and carbon tax regimes with distinctions between large industrial emissions (facilities emitting greater than 100,000 tonnes of GHG annually) and end-use emissions (those from transportation and heating fuels). The Report also states that the 100 megatonne limit on oil sands facilities will be subject to exceptions for cogeneration and new upgrading capacity.

The SGRR introduces the Specified Gas Reporting Standard (the Standard), a document published by Alberta Environment and Parks, which sets out the minimum emission levels before facility reporting requirements begin. Under the current version of the Standard, the threshold level for submission of a specified gas report is the release of 50,000 tonnes of GHG in a calendar year. Regulated facilities must also report emissions of industrial air pollutants and comply with obligations imposed under permits. Alberta s 2008 climate change plan set a goal of 14% absolute reduction in GHG emissions below 2005 levels in the province by 2050. Whether or not the impending climate change plan from the new Government of Alberta will align with this goal remains to be seen.

In Saskatchewan, The Management and Reduction of Greenhouse Gases Act (MRGGA) received royal assent on May 20, 2010; however, currently, there does not appear to be political will to progress the MRGGA.

Water

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act (CWA), and analogous state and Canadian federal and provincial laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters of the United States and Canada, as well as state and provincial waters. See Pipeline Safety/Pipeline and Storage Tank Integrity Management above and Note 16 to our Consolidated Financial Statements. Federal, state and provincial regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with discharge permits or other requirements of the CWA.

The Oil Pollution Act of 1990 (OPA) amended certain provisions of the CWA, as they relate to the release of petroleum products into navigable waters. OPA subjects owners of facilities to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages and certain other consequences of an oil spill. 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 the past 35 years, the Corps has authorized construction, maintenance and repair of pipelines under a streamlined nationwide permit program known as Nationwide Permit 12 (NWP). The NWP is supported by strong statutory and regulatory history and was originally approved by Congress in 1977. From time to time, environmental groups have challenged the NWP; however, to date, federal courts have upheld the validity of the NWP under the CWA. We cannot predict whether future lawsuits will be filed to contest the validity of the NWP; however, in the event that a court wholly or partially strikes down the NWP, which we believe to be unlikely, we could face significant delays and financial costs when seeking project approvals from the Corps. In addition, the EPA published a final rule in May 2015 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.

Endangered Species

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

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

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

Regulation of OCS Pipelines. The Outer Continental Shelf Lands Act requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. In June 2008, the Minerals Management Service (now replaced by the Bureau of Ocean Energy Management, Regulation and Enforcement) issued a final rule establishing formal and informal complaint procedures for shippers that believe they have been denied open and nondiscriminatory access to transportation on the OCS.

Energy Policy Act of 1992 and Subsequent Developments. In October 1992, Congress passed the Energy Policy Act of 1992 (EPAct), which, among other things, required the FERC to issue rules to establish a simplified and generally applicable ratemaking methodology for petroleum pipelines and to streamline procedures in petroleum pipeline proceedings. The FERC responded to this mandate by establishing a formulaic methodology for petroleum pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index. The FERC reviews the formula every five years. Effective July 1, 2011, the annual index adjustment for the five year period ending June 30, 2016 will equal the producer price index for finished goods for the applicable year plus an adjustment factor of 2.65%. In December 2015, the FERC established an index level of the producer price index for finished goods plus 1.23% for the five-year period commencing July 1, 2016. Pipelines may raise their rates to the rate ceiling level generated by application of the annual index adjustment factor each year; however, a shipper may challenge such increase if the increase in the pipeline s rates was substantially in excess of the actual cost increases incurred by the pipeline during the relevant year. If the FERC s annual index adjustment reduces the ceiling level such that it is lower than a pipeline s filed rate, the pipeline must reduce its rate to conform with the lower ceiling unless doing so would reduce a rate grandfathered by the EPAct (see below) to below the grandfathered level. A pipeline must, as a general rule, use the indexing methodology to change its rates. The FERC, however, retained cost-of-service ratemaking, market-based rates and settlement rates as alternatives to the indexing approach that may be used in certain specified circumstances. Because the indexing methodology for the next five-year period is tied to an inflation index and is not based on pipeline-specific costs, the indexing methodology could hamper our ability to recover cost increases.

Under the EPAct, petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of EPAct are deemed to be just and reasonable under the ICA, if such rates had not been subject to complaint, protest or investigation during such 365-day period. Generally, complaints against such grandfathered rates may only be pursued if the complainant can show that a substantial change has occurred since the enactment of EPAct in either the economic circumstances of the oil pipeline or in the nature of the services provided that were a basis for the rate. EPAct places no such limit on challenges to a provision of an oil pipeline tariff as unduly discriminatory or preferential.

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

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

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Trucking Regulation

United States

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

Canada

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

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. The rule also includes new operational requirements such as speed restrictions. On December 3, 2015, Congress passed the Fixing America s Transportation (FAST) Act which was subsequently signed by the President on December 7, 2015. 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 certain vapor pressure limits.

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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.

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

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more than a de minimis volume of natural gas report annual numbers and volumes of relevant transactions to the FERC. Our natural gas storage facilities and related marketing entities are subject to these annual reporting requirements.

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

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

Operational Hazards and Insurance

Pipelines, terminals, trucks or other facilities or equipment may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. Since the time we and our predecessors commenced midstream crude oil activities in the early 1990s, we have maintained insurance of various types and varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. However, such insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. Consistent with insurance coverage generally available to the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences. Over the last several years, our operations have expanded significantly, with total PAA assets increasing over 35 times since the end of 1998. At the same time that the scale and scope of our business activities have expanded, the breadth and depth of the available insurance markets have contracted. The overall cost of such insurance as well as the deductibles and overall retention levels that we maintain have increased. As a result, we have elected to self-insure more activities against certain of these operating hazards and expect this trend will continue in the future. Due to the events of September 11, 2001, insurers have excluded acts of terrorism and sabotage from our insurance policies. We have elected to purchase a separate insurance policy for acts of terrorism and sabotage.

Since the terrorist attacks, the United States Government has issued numerous warnings that energy assets, including our nation s pipeline infrastructure, may be future targets of terrorist organizations. These developments expose our operations and assets to increased risks. We have instituted security measures and procedures in conformity with DOT guidance. We will institute, as appropriate, additional security measures or procedures indicated by the DOT or the Transportation Safety Administration. However, there can be no assurance that these or any other security measures would protect our facilities from an attack. Any future terrorist attacks on our facilities, those of our customers and, in some cases, those of our competitors, could have a material adverse effect on our business, whether insured or not.

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

Title to Properties and Rights-of-Way

Our real property holdings are generally comprised of: (i) parcels of land that we own in fee, (ii) surface leases, underground storage leases and (iii) easements, rights-of-way, permits, crossing agreements or licenses from landowners or governmental authorities permitting the use of certain lands for our operations. We believe we have satisfactory title or the right to use the sites upon which our significant facilities are located, subject to customary liens, restrictions or encumbrances. 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

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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 5,400 employees at December 31, 2015. None of these employees were subject to a collective bargaining agreement, except for nine employees covered by an agreement scheduled for renegotiation in September 2016 and another nine employees covered by a separate agreement scheduled for renegotiation in September 2018. Also, a first collective agreement is being negotiated for 66 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 and administrative rulings and judicial decisions, all as in effect on the date hereof, and all of which are subject to change, possibly with retroactive effect. We have not sought any ruling from the Internal Revenue Service, or the IRS, with respect to the statements made and the conclusions reached in the following summary, and there can be no assurance that the IRS will agree with such statements and conclusions.

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

Corporate Status

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

Consequences to U.S. Holders

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

- an individual citizen or resident of the United States;

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

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

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

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Distributions

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

Both AAP and PAA have made elections permitted by Section 754 of the Code. As a result, our initial acquisition of interests in AAP resulted in basis adjustments with respect to our interest in the assets of AAP (and indirectly in PAA). Such adjustments resulted in depreciation and amortization deductions that we anticipate will offset a substantial portion of our taxable income for an extended period of time. In addition, future exchanges of retained interests in AAP and Class B shares in us for our 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, 2016 and 2017 and we may not have sufficient earnings and profits during future tax years for any distributions on our Class A shares to qualify as dividends for U.S. federal income tax purposes. If a distribution on our Class A shares fails to qualify as a dividend for U.S. federal income tax purposes, U.S. corporate holders would be unable to utilize the corporate dividends-received deduction.

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

Gain on Disposition of Class A Shares

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

Backup Withholding and Information Reporting

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

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

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Consequences to Non-U.S. Holders

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

Distributions

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

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

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

Gain on Disposition of Class A Shares

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

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

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

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

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

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

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

U.S. Federal Estate Tax

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

Backup Withholding and Information Reporting

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

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

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

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

Legislation Affecting Class A Shares Held Through Foreign Accounts

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

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

3.8% Tax on Unearned Income

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

Available Information

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

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

Risks Inherent in an Investment in Us

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

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

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

- AAP s payment of costs and expenses associated with our operations, and the operations of GP LLC, including expenses we incur as a result of being a public company, to the extent they are not subject to reimbursement by PAA;
- our payment of any income taxes;
- interest expense and principal payments on any indebtedness incurred by AAP or us;
- restrictions on distributions contained in AAP s and PAA s respective credit facilities and any future debt agreements entered into by AAP, PAA or us;
- reserves necessary for us to pay a ratable amount to AAP as necessary to permit AAP to make required capital contributions to PAA to maintain AAP s indirect 2% general partner interest in PAA, as required by the partnership agreement of PAA upon the issuance of additional partnership interests by PAA; and

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

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

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

At December 31, 2015, we owned an approximate 38% limited partner interest in AAP, which owns all of PAA s IDRs, which entitle AAP to receive increasing percentages (up to a maximum of 48%, to the extent not modified) of any cash distributed by PAA in excess of $0.225 per PAA common unit in any quarter. The vast majority of the cash flow we receive from AAP is derived from its ownership of these IDRs.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

In addition, if our Class A shareholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner. Our general partner may only be removed by vote of the holders of at least 66 2/3% of our outstanding

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shares (including both Class A and Class B shares). At December 31, 2015, the Legacy Owners owned approximately 62% of our outstanding shares. This ownership level enables the Legacy Owners to prevent our general partner s removal.

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

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

Our general partner may cause us to issue an unlimited number of additional Class A shares or other equity securities of equal rank with the Class A shares, or cause AAP to issue additional securities, in each case without shareholder approval. In addition, we may issue an unlimited number of shares that are senior to our Class A shares in right of distribution, liquidation and voting. Except for Class A shares issued in connection with the exercise of an Exchange Right, which will result in the cancellation of an equivalent number of Class B shares and therefore have no effect on the total number of outstanding shares, the issuance of additional Class A shares or our other equity securities of equal or senior rank, or the issuance by AAP of additional securities, will have the following effects:

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

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

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

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

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

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

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

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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. In addition, our partnership agreement contains provisions limiting the ability of our shareholders to call meetings or to acquire information about our operations, as well as other provisions limiting our shareholders ability to influence the manner or direction of our management. As a result, the price at which our Class A shares will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

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

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

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

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

- PAA s operating and financial performance and prospects and the trading price of its common units;
- the level of PAA s quarterly distributions and our quarterly distributions;
- quarterly variations in the rate of growth of our financial indicators, such as distributable cash flow per Class A share, net income and revenues;
- changes in revenue or earnings and distribution estimates or publication of research reports by analysts;
- speculation by the press or investment community;
- sales of our Class A shares by our shareholders;
- the exercise by the Legacy Owners of their exchange rights with respect to any retained AAP units;
- announcements by PAA or its competitors of significant contracts, acquisitions, strategic partnerships, joint ventures, securities offerings or capital commitments;

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- 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, 2015, the Legacy Owners held approximately 62% 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 $1.8 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.

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

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

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

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

Risks Related to Conflicts of Interest

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

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

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

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

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

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

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

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

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- 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 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, 2015, the Legacy Owners owned approximately 62% of our outstanding shares and approximately 62% of the AAP units. As a result, the Legacy Owners may have conflicting interests with holders of Class A shares. For example, the Legacy Owners may have different tax positions from us which could influence their decisions regarding whether and when to cause us to dispose of assets.

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

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

Pursuant to the administrative agreement, we have agreed to certain business opportunity arrangements to address potential conflicts with respect to business opportunities that may arise among us, our general partner, PAA, PAA GP, AAP and GP LLC. If a business opportunity is presented to us, our general partner, PAA, PAA GP, AAP or GP LLC, then PAA will have the first right to pursue such business opportunity. We have the right to pursue and/or participate in such business opportunity if invited to do so by PAA, or if PAA abandons the business