PLAINS ALL AMERICAN PIPELINE LP
Form 10-K
February 25, 2016
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2015

or

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

Commission file number 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

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

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

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

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

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

The aggregate market value of the Common Units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Common Units outstanding, for this purpose, as if they may be affiliates of the registrant) was approximately $17.1 billion on June 30, 2015, based on a closing price of $43.57 per Common Unit as reported on the New York Stock Exchange on such date.

As of February 12, 2016, there were 397,730,991 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

NONE

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

FORM 10-K 2015 ANNUAL REPORT

Table of Contents

Table of Contents

FORWARD-LOOKING STATEMENTS

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements incorporating the words anticipate, believe, estimate, expect, plan, intend and forecast, as well as similar expressions and st regarding our business strategy, plans and objectives for future operations. The absence of such words, expressions or statements, however, does not mean that the statements are not forward-looking. Any such forward-looking statements reflect our current views with respect to future events, based on what we believe to be reasonable assumptions. Certain factors could cause actual results or outcomes to differ materially from the results or outcomes anticipated in the forward-looking statements. The most important of these factors include, but are not limited to:

- 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 our credit rating and ability to receive open credit from our 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 our historical operations;

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

- the effectiveness of our risk management activities;

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

Table of Contents

- 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 our units at the time of vesting under our 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.

PART I

Items 1 and 2. ***Business and Properties***

General

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

We own and operate midstream energy infrastructure and provide logistics services for crude oil, natural gas liquids (NGL), natural gas and refined products. We own an extensive network of pipeline transportation, terminalling, storage, and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. Our business activities are conducted through three operating segments: Transportation, Facilities and Supply and Logistics.

Organizational History

We were formed as a master limited partnership to acquire and operate the midstream crude oil businesses and assets of a predecessor entity and completed our initial public offering in 1998. Our 2% general partner interest is held by PAA GP LLC, a Delaware limited liability company, whose sole member is Plains AAP, L.P., a Delaware limited partnership (AAP). In addition to its ownership of PAA GP LLC, AAP also owns all of our incentive distribution rights (IDRs). Plains All American GP LLC, a Delaware limited liability company (GP LLC), is AAP s general partner. References to our general partner, as the context requires, include any or all of PAA GP LLC, AAP and GP LLC.

Plains GP Holdings, L.P. (PAGP), a Delaware limited partnership that completed its initial public offering in October 2013 and that has elected to be treated as a corporation for U.S. federal income tax purposes, is the sole member of GP LLC, and at December 31, 2015, owned an approximate 38% limited partner interest in AAP (an approximate 35% economic interest). PAA GP Holdings LLC, a Delaware limited liability company (GP Holdings), is the general partner of PAGP.

Partnership Structure and Management

Our operations are conducted directly and indirectly through, and our operating assets are owned by, our subsidiaries. GP LLC has responsibility for conducting our business and managing our operations; however, PAGP effectively controls our business and affairs through the exercise of its rights as the sole and managing member of our general partner, including its right to

Table of Contents

appoint certain members to the board of directors of our general partner. See Item 10. Directors and Executive Officers of our General Partner and Corporate Governance. Our general partner does not receive a management fee or other compensation in connection with its management of our business, but it is reimbursed for substantially all direct and indirect expenses incurred on our behalf (other than expenses related to the Class B units of AAP, which are referred to herein as the AAP Management Units).

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

Summarized Partnership Structure

(as of December 31, 2015) **(1)**

(1) In January 2016, we completed the sale of approximately 61.0 million Series A Convertible Preferred Units representing limited partner interests in us. 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.

Table of Contents

Detailed Partnership Structure

(as of December 31, 2015) (1)

Table of Contents

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

(2) See Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities for discussion of our general partner s IDRs.

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

(4) The Partnership 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).

(5) Represents the number of Class A units of AAP (AAP units) for which the AAP Management Units would be exchangeable, assuming a conversion rate of approximately 0.938 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.

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

Business Strategy

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

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

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

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

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

Competitive Strengths

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

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

Table of Contents

- *We possess specialized crude oil and NGL market knowledge.* We believe our business relationships with participants in various phases of the crude oil and NGL distribution chain, from producers to refiners, as well as our own industry expertise (including our knowledge of North American crude oil and NGL flows), provide us with an extensive understanding of the North American physical crude oil and NGL markets.

- *Our supply and logistics activities typically generate a base level of margin with the opportunity to realize incremental margins.* We believe the variety of activities executed within our Supply and Logistics segment in combination with our risk management strategies provides us with a balance that typically provides us 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, we may be able to realize incremental margins during volatile market conditions.

- *We have the evaluation, integration and engineering skill sets and the financial flexibility to continue to pursue acquisition and expansion opportunities.* Since 1998, we have completed and integrated over 85 acquisitions with an aggregate purchase price of approximately $11.7 billion. We have also implemented expansion capital projects totaling approximately $10 billion. In addition, considering our investment grade credit rating, liquidity and capital structure, we believe we have the financial resources and strength necessary to finance future strategic expansion and acquisition opportunities. As of December 31, 2015, we had approximately $2.3 billion of liquidity available, including cash and cash equivalents and availability under our committed credit facilities, subject to continued covenant compliance.

- *We have an experienced management team whose interests are aligned with those of our unitholders.* Our executive management team has an average of 31 years industry experience, and an average of 18 years with us or our predecessors and affiliates. In addition, through their ownership of common units, indirect interests in our general partner, grants of phantom units and AAP Management Units, our management team has a vested interest in our continued success.

Financial Strategy

Targeted Credit Profile

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

- an average long-term debt-to-total capitalization ratio of approximately 50% 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. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Non-GAAP Financial Measures for a discussion of our selected items that impact comparability and our non-GAAP measures.);

- an average total debt-to-total capitalization ratio of approximately 60% or less; and

- an average adjusted EBITDA-to-interest coverage multiple of approximately 3.3x or better.

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

Typically, to maintain our targeted credit profile and achieve growth through acquisitions and expansion capital, we fund 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 our ongoing capital program and maintain a solid capital structure and significant liquidity, in January 2016, we 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, we may be outside the parameters of our 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

Table of Contents

gap in the timing between funding our capital program and the time the assets are placed in service and begin to generate cash flow, we expect our long-term debt-to-adjusted EBITDA to be above our target range for the near-term. We expect this leverage ratio will improve and return to our targeted levels as the industry recovers and we realize EBITDA growth from our capital investments.

Acquisitions

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

The following table summarizes acquisitions greater than $200 million that we have completed over the past five years.

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)

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(1) Excludes our acquisition of all of the outstanding publicly-traded common units of PAA Natural Gas Storage, L.P. (PNG) on December 31, 2013 (referred to herein as the PNG Merger), as we historically consolidated PNG into our financial statements for financial reporting purposes in accordance with generally accepted accounting principles in the United States (GAAP). As consideration for the PNG Merger, we issued approximately 14.7 million PAA common units with a value of approximately $760 million. See Note 10 to our Consolidated Financial Statements for further discussion of the PNG Merger.

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

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

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

(5) Includes 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.

Table of Contents

Ongoing Acquisition and Investment Activities

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

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

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

Expansion Capital Projects

Our extensive asset base and our relationships with customers provide us with opportunities for organic growth through the construction of additional assets that are complementary to, and expand or extend, our existing asset base. We believe that the diversity and balance of our expansion capital project portfolio (i.e., relatively large number of projects that are small to medium sized and spread across multiple geographic regions) reduces our overall exposure to cost overruns, timing delays and other adverse market developments with respect to a particular project or region. Our 2016 expansion capital plan is representative of the diversity and balance of our overall project portfolio. The following expansion capital projects are included in our 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 our 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	2016

			capacity (increases pipeline capacity to 330,000 Bbls/d)	
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

10

Table of Contents

Basin/Region	Project	2016 Plan Amount (1) ($ in millions)	Description	Projected In-Service Date
	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
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.

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.

Table of Contents

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

Table of Contents

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.

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.

Table of Contents

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.

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.

Table of Contents

Natural Gas Storage Market Overview

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

Overall market conditions for natural gas storage have been challenging during the last several years, driven by a variety of factors, including (i) increased natural gas supplies due to production from shale resources, (ii) a shift from Gulf of Mexico production to Northeast production causing less concern over disruptions from tropical weather, (iii) increased availability of storage capacity 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

Our business activities are conducted through three segments Transportation, Facilities and Supply and Logistics. We have an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. The map below highlights our more significant assets (including certain assets under construction or development) as of December 31, 2015:

Table of Contents

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

Transportation Segment

Our Transportation segment operations generally consist of fee-based activities associated with transporting crude oil and NGL on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third-party pipeline capacity agreements and other transportation fees. Our Transportation segment also includes equity earnings from our investments in 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**

Table of Contents

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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.

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.

Table of Contents

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.

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.

Table of Contents

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.

Table of Contents

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.

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

Table of Contents

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

- 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

Table of Contents

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

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

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(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

Table of Contents

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.

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.

Table of Contents

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.

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.

Table of Contents

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%.

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.

Table of Contents

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;

- 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:

Table of Contents

- 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

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

Table of Contents

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.

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.

Table of Contents

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.

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

Table of Contents

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.

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

Table of Contents

operation, replacement and management of pipeline and tank facilities. Federal regulations implementing the HLPSA require pipeline operators to adopt measures designed to reduce the environmental impact of oil discharges from onshore oil pipelines, including the maintenance of comprehensive spill response plans and the performance of extensive spill response training for pipeline personnel. These regulations also require pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. Comparable regulation exists in some states in which we conduct intrastate common carrier or private pipeline operations. Regulation in Canada is under the National Energy Board (NEB) and provincial agencies.

United States

The HLPSA was amended by the Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. These amendments have resulted in the adoption of rules by the Department of Transportation (DOT) that require transportation pipeline operators to implement integrity management programs, including 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, (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.

Table of Contents

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.

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

Table of Contents

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.

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

Table of Contents

is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our ordinary operations, we may generate waste that falls within CERCLA s definition of a hazardous substance. Canadian federal and provincial laws also impose liabilities for releases of certain substances into the environment.

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

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

Trucking Regulation

United States

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

Canada

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

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.

Table of Contents

Cross Border Regulation

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

Market Anti-Manipulation Regulation

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

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

Table of Contents

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 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

Table of Contents

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

To carry out our operations, our general partner or its affiliates (including PMC) 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. Our general partner and its affiliates consider employee relations to be good.

Summary of Tax Considerations

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

Partnership Status; Cash Distributions

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

Partnership Allocations

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

Basis of Common Units

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

Limitations on Deductibility of Partnership Losses

The deduction by a unitholder of that unitholder s allocable share of our losses will be limited to the amount of that unitholder s tax basis in his or her common units and, in the case of an individual unitholder or a corporate unitholder who is subject to the at risk rules (generally, certain closely-held corporations), to the amount for which the unitholder is considered to be at risk

Table of Contents

with respect to our activities, if that is less than the unitholder s tax basis. A unitholder must recapture losses deducted in previous years to the extent that distributions cause the unitholder s at risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable as a deduction to the extent that his at-risk amount is subsequently increased, provided such losses do not exceed such unitholder s tax basis in his common units. Upon the taxable disposition of a common unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but may not be offset by losses suspended by the basis limitation. Any loss previously suspended by the at risk limitation in excess of that gain could no longer be used.

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

Section 754 Election

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

Disposition of Common Units

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

State, Local and Other Tax Considerations

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

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

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

An investment in common units by tax-exempt organizations (including Individual Retirement Accounts (IRAs) and other retirement plans) and non-U.S. persons raises issues unique to such persons. Virtually all of our income allocated to a unitholder that is a tax-exempt organization is unrelated business taxable income and, thus, is taxable to such a unitholder. A unitholder who is a

Table of Contents

nonresident alien, non-U.S. corporation or other non-U.S. person is regarded as being engaged in a trade or business in the United States as a result of ownership of a common unit and, thus, is required to file federal income tax returns and to pay tax on the unitholder s share of our taxable income. Finally, distributions to non-U.S. unitholders are subject to federal income tax withholding at the highest applicable rate.

Available Information

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

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

Risks Related to Our Business

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

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

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

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

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

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

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

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

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

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

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

Our profitability could be materially impacted by a decline in the volume of crude oil, natural gas, refined product and NGL transported, gathered, stored or processed at our facilities. A material decrease in crude oil or natural gas production or crude oil refining, as a result of depressed commodity prices, natural decline rates attributable to crude oil and natural gas reservoirs, a decrease

Table of Contents

in exploration and development activities, supply disruptions, economic conditions or otherwise, could result in a decline in the volume of crude oil, natural gas, refined product or NGL handled by our facilities and other energy logistics assets.

During the latter half of 2014 and continuing throughout 2015, benchmark crude oil prices declined significantly; as a result, many of the companies that produce oil and gas reduced capital expenditures for 2015 and announced further reductions for 2016. Such reduced expenditure levels, coupled with high decline rates for many horizontal wells in the shale resource plays is beginning to lead to production declines in the Lower 48 United States (excluding Gulf of Mexico production). Other factors that could adversely impact production include reduced capital market access, increased capital raising costs for producers or adverse governmental or regulatory action. In turn, such developments could lead to reduced throughput on our pipelines and at our other facilities, which, depending on the level of production declines, could have a material adverse effect on our business.

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

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

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

Supply and demand for crude oil and other hydrocarbon products we handle is dependent upon a variety of factors, including price, the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation, including climate change regulations, and technological advances in fuel economy and energy generation devices. For example, the adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could increase the cost of consuming crude oil and other hydrocarbon products, thereby causing a reduction in the demand for such products. Demand also depends on the ability and willingness of shippers having access to our transportation assets to satisfy their demand by deliveries through those assets. The supply of crude oil depends on a variety of global political and economic factors, including the reliance of foreign governments on petroleum revenues. Excess global supply of crude oil may negatively impact our operating results by decreasing the price of crude oil and making production and transportation less profitable in areas we service.

Fluctuations in demand for crude oil, such as those caused by refinery downtime or shutdowns, can have a negative effect on our operating results. Specifically, reduced demand in an area serviced by our transportation systems will negatively affect the throughput on such systems. Although the negative impact may be mitigated or overcome by our ability to capture differentials created by demand fluctuations, this ability is dependent on location and grade of crude oil, and thus is unpredictable.

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

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

Our results of operations are influenced by the overall forward market for crude oil, and certain market structures or the absence of pricing volatility may adversely impact our results.

Results from our Supply and Logistics segment are influenced by the overall forward market for crude oil. A contango market is favorable to commercial strategies that are associated with storage capacity as it allows a party to simultaneously purchase crude oil at current prices for storage and sell at higher prices for future delivery. Wide contango spreads combined with price structure volatility generally have a favorable impact on our results. A backwardated market (meaning that the price of crude oil for future deliveries is lower than current prices) can have a positive impact on lease gathering margins because in certain circumstances crude oil gatherers can capture a premium for prompt deliveries; however, in this environment there is little incentive to store crude oil as current prices are above future delivery prices. In either case, margins can be improved when prices are volatile. The periods between these two market structures are referred to as transition periods. If the market is in a backwardated to transitional structure, our results from our Supply and Logistics segment may be less than those generated during the more favorable contango market conditions. Additionally, a prolonged transition period or a lack of volatility in the pricing structure may further negatively impact our results. Depending on the overall duration of these transition periods, how we have allocated our assets to particular strategies and the time length of our crude oil purchase and sale contracts and storage agreements, these transition periods may have either an adverse or beneficial effect on our aggregate segment profit. A prolonged transition from a backwardated market to a contango market, or vice versa (essentially a market that is neither in pronounced backwardation nor contango), represents the least beneficial environment for our Supply and Logistics segment.

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

Some of our operations involve risks of personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes. The location of some of our assets and our customers assets in the U.S. Gulf Coast region makes them particularly vulnerable to hurricane or tropical storm risk. Our facilities and operations are also vulnerable to accidents caused by process safety failures, equipment failures or human error. In addition, since the September 11, 2001 terrorist attacks, the U.S. government has issued warnings that energy assets, specifically the nation s pipeline infrastructure, may be future targets of terrorist organizations. Terrorists may target our physical facilities and hackers may attack our electronic and computer systems.

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

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

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

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

A significant driver of competition in some of the markets where we operate (including, for example, the Eagle Ford, Permian Basin, and Rockies/Bakken areas) stems from the rapid development of new midstream energy infrastructure capacity that was driven by the combination of (i) significant increases in oil and gas production and development in the applicable production areas, both actual and anticipated, (ii) relatively low barriers to entry and (iii) generally widespread access to relatively low cost capital. While this environment presented opportunities for us, many of these areas have become overbuilt, resulting in an excess of midstream energy infrastructure capacity. In addition, as an established participant in some markets, we also face competition from aggressive new entrants to the market that are willing to provide services at a discount in order to establish relationships and gain a foothold in the market. Current expectations for oil and gas development in many of the areas where we operate are not as robust as they were during the last few years. This adversely impacts both our existing assets and growth projects in such areas. We also face competition for incremental volumes from shippers on third party pipelines who overcommitted relative to their actual production and are now purchasing barrels on the open market and shipping them on such third party pipelines in order to satisfy their minimum commitment levels. This puts downward pressure on our throughput and margins and, together with other adverse competitive effects,

Table of Contents

could have a significant adverse impact on our financial position, cash flows and ability to pay or increase distributions to our unitholders.

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

With respect to our natural gas storage operations, the principal elements of competition are rates, terms of service, supply and market access and flexibility of service. Our natural gas storage facilities compete with several other storage providers, including regional storage facilities and utilities. Certain pipeline companies have existing storage facilities connected to their systems that compete with some of our facilities.

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

Our growth strategy requires access to new capital. Tightened capital markets or other factors that increase our cost of capital could impair our ability to grow.

We continuously consider potential acquisitions and opportunities for expansion capital projects. Acquisition transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets and operations. Our ability to fund our capital projects and make acquisitions depends on whether we can access the necessary financing to fund these activities. Any limitations on our access to capital or increase in the cost of that capital could significantly impair our growth strategy. Our ability to maintain our targeted credit profile, including maintaining our credit ratings, could affect our cost of capital as well as our ability to execute our growth strategy. In addition, a variety of factors beyond our control could impact the availability or cost of capital, including domestic or international economic conditions, increases in key benchmark interest rates and/or credit spreads, the adoption of new or amended banking or capital market laws or regulations, the re-pricing of market risks and volatility in capital and financial markets. In the latter half of 2015, the depth and availability of conventional public equity and debt markets contracted while the costs of accessing such markets rose significantly.

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

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

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

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

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

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

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

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

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

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

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

Acquisitions involve risks that may adversely affect our business.

Any acquisition involves potential risks, including:

- performance from the acquired businesses or assets that is below the forecasts we used in evaluating the acquisition;
- a significant increase in our indebtedness and working capital requirements;
- the inability to timely and effectively integrate the operations of recently acquired businesses or assets;
- the incurrence of substantial unforeseen environmental and other liabilities arising out of the acquired businesses or assets for which we are either not indemnified, or the indemnity is not from a credit-worthy party, including liabilities arising from the operation of the acquired businesses or assets prior to our acquisition;
- risks associated with operating in lines of business that are distinct and separate from our historical operations;
- customer or key employee loss from the acquired businesses; and
- the diversion of management s attention from other business concerns.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows from our acquisitions, realize other anticipated benefits and our ability to pay distributions to our partners or meet our debt service requirements.

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

Generally, it is our policy to establish a margin for crude oil or other products we purchase by selling such products for physical delivery to third-party users, or by entering into a future delivery obligation under derivative contracts. Through these transactions, we seek to maintain a position that is substantially balanced between purchases on the one hand, and sales or future delivery obligations on the other hand. Our policy is not to acquire and hold physical inventory or derivative products for the purpose of speculating on commodity price changes. These policies and practices cannot, however, eliminate all risks. For example, any event that disrupts our anticipated physical supply of crude oil or other products could expose us to risk of loss resulting from price changes. We are also exposed to basis risk when crude oil or other products are purchased against one pricing index and sold against a different index. Moreover, we are exposed to some risks that are not hedged, including risks on certain of our inventory, such as linefill, which

must be maintained in order to transport crude oil on our pipelines. In an effort to maintain a balanced position, specifically authorized personnel can purchase or sell crude oil, refined products and NGL, up to predefined limits and authorizations. Although this activity is monitored independently by our risk management function, it exposes us to commodity price risks within these limits.

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

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

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons, including crude oil, NGL and refined products, as well as our operations involving the storage of natural gas, are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment. Our operations are also subject to laws and regulations relating to protection of the environment and wildlife, operational safety, climate change and related matters. Compliance with all of these laws and regulations increases our overall cost of doing business, including our capital costs to construct, maintain and upgrade equipment and facilities. For example, the adoption of legislation or regulatory programs to reduce emissions of greenhouse gases, including cap and trade programs, could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. In addition, with respect to our railcar operations, the adoption of new regulations designed to enhance the overall safety of crude oil and natural gas liquids transportation by rail, including new regulations requiring that existing railcars be retrofitted or upgraded to improve integrity, could result in increased operating costs and potentially involve substantial capital expenditures. Also, the failure to comply with any such laws and regulations could result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, the issuance of injunctions that may subject us to additional operational requirements and constraints, or claims of damages to property or persons resulting from our operations. The laws and regulations applicable to our operations are subject to change and interpretation by the relevant governmental agency, including the possibility that exemptions we currently qualify for may be modified or changed in ways that require us to incur significant additional compliance costs. Any such change or interpretation adverse to us could have a material adverse effect on our operations, revenues, expenses and profitability.

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

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

For 2016 and beyond, we will continue to focus on pipeline integrity management as a primary operational emphasis. In that regard, we have implemented programs intended to maintain the integrity of our assets, with a focus on risk reduction through testing, enhanced corrosion control, leak detection, and damage prevention. We have an internal review process pursuant to which we examine various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management mandate. The purpose of this process is to review the surrounding environment, condition and operating history of these pipeline and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, in addition to potential cost increases related to unanticipated regulatory changes or injunctive remedies resulting from regulatory agency enforcement actions, we may elect (as a result of our own internal initiatives) to spend substantial sums to enhance the integrity of and upgrade our pipeline systems to

Table of Contents

maintain environmental compliance and, in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines. We cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures but any such expenditures could be significant. See Item 3 Legal Proceedings Environmental General. In addition, despite our pipeline and facility integrity management efforts, we can provide no assurance that our pipelines and facilities will not experience leaks or releases or that we will be able to fully comply with all of the federal, state and local laws and regulations applicable to the operation of our pipelines or facilities; any such leaks or releases could be material and could have a significant adverse impact on our reputation, financial position, cash flows and ability to pay or increase distributions to our unitholders.

Our assets are subject to federal, state and provincial regulation. Rate regulation or a successful challenge to the rates we charge on our U.S. and Canadian pipeline systems may reduce the amount of cash we generate.

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

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

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

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

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

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

The FTC, the FERC and the CFTC hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil, natural gas, NGL or other energy commodities, and any related transportation and/or hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Additionally, to the extent that we enter into transportation contracts with natural gas pipelines that are subject to FERC regulation, we are subject to FERC requirements related to the use of such capacity. Any failure on our part to comply with the regulations and policies of the FERC, the FTC or the CFTC could result in the imposition of civil and criminal penalties. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Table of Contents

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

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

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

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

Certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we qualify for the end-user exception from margin requirements for swaps entered into to hedge commercial risks, if any of our swaps do not qualify for the commercial end-user exception, a requirement to post additional cash margin or collateral could reduce our ability to execute hedges necessary to reduce commodity price exposures and protect cash flows. Posting of additional cash margin or collateral could affect our liquidity (defined as unrestricted cash on hand plus available capacity under our credit facilities) and reduce our ability to use cash for capital expenditures or other partnership purposes.

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

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

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

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

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

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

Over the last several years, as the scale and scope of our business activities has expanded, the breadth and depth of available insurance markets has contracted. As a result of these factors and other market conditions, as well as the fact that we have experienced several incidents over the last 3 to 5 years, premiums and deductibles for certain insurance policies have increased substantially. Accordingly, we can give no assurance that we will be able to maintain adequate insurance in the future at rates or on other terms we consider commercially reasonable. In addition, although we believe that we currently maintain adequate insurance coverage, insurance will not cover many types of interruptions or events that might occur and will not cover all risks associated with our operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur. The occurrence of a significant event, the consequences of which are either not covered by insurance or not fully insured, or a significant delay in the payment of a major insurance claim, could materially and adversely affect our financial position, results of operations and cash flows.

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

As of December 31, 2015, the principal amount of our consolidated debt outstanding was approximately $11.5 billion, consisting of approximately $10.5 billion principal amount of long-term debt (including senior notes and long-term commercial paper borrowings) and approximately $1.0 billion of short-term borrowings. As of December 31, 2015, we had approximately $2.3 billion of liquidity available, including cash and cash equivalents and available borrowing capacity under our senior unsecured revolving credit facility, our senior secured hedged inventory facility and our senior unsecured 364-day credit facility, subject to continued covenant compliance. Lower adjusted EBITDA could increase our leverage ratios and effectively reduce our ability to incur additional indebtedness.

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

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

- credit rating agencies may view our debt level negatively;

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

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

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

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

Our credit agreements prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, the agreements contain various covenants limiting our ability to, among other things, incur indebtedness if certain financial ratios are not maintained, grant liens, engage in transactions with affiliates, enter into sale-leaseback transactions, and sell substantially all of our assets or enter into a merger or consolidation. Our credit facility treats a change of control as an event of default and also requires us to maintain a certain debt coverage ratio. Our senior notes do not restrict distributions to unitholders, but a default under our credit agreements will be treated as a default under the senior notes. Please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Agreements, Commercial Paper Program and Indentures.

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

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

As of December 31, 2015, we had approximately $11.5 billion in principal amount of consolidated debt, of which approximately $9.8 billion was at fixed interest rates and approximately $1.7 billion was at variable interest rates. We are exposed to market risk due to the short-term nature of our commercial paper borrowings and the floating interest rates on our credit facilities. Our results of operations, cash flows and financial position could be adversely affected by significant increases in interest rates above current levels. Additionally, increases in interest rates could adversely affect our Supply and Logistics segment results by increasing interest costs associated with the storage of hedged crude oil and NGL inventory. Further, the trading price of our common units may be sensitive to changes in interest rates and any rise in interest rates could adversely impact such trading price.

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

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

An impairment of long-term assets could reduce our earnings.

At December 31, 2015, we had approximately $13.5 billion of net property and equipment, $2.4 billion of goodwill, $2.0 billion of investments accounted for under the equity method of accounting and $0.3 billion of net intangible assets capitalized on our balance sheet. GAAP requires an assessment for impairment on an annual basis or in certain circumstances, including when there is an indication that the carrying value of property and equipment may not be recoverable or a determination that it is more likely than not that a reporting unit s carrying value is in excess of the reporting unit s fair value. If we were to determine that any of our property and equipment, goodwill, intangibles or equity method investments was impaired, we could be required to take an immediate charge to earnings, which could adversely impact our operating results, with a corresponding reduction of partners capital and increase in balance sheet leverage as measured by debt-to-total capitalization.

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

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

We are dependent on use of third-party assets for certain of our operations.

Certain of our business activities require the use of third-party assets over which we may have little or no control. For example, a portion of our storage and distribution business conducted in the Los Angeles basin receives waterborne crude oil through dock facilities operated by a third party in the Port of Long Beach. If at any time our access to this dock was denied, and if access to an alternative dock could not be arranged, the volume of crude oil that we presently receive from our customers in the Los Angeles basin may be reduced, which could result in a reduction of Facilities segment revenue and cash flow.

Table of Contents

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

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

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

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

- a failure on the part of our storage facilities to perform as we expect them to, whether due to malfunction of equipment or facilities or realization of other operational risks;

- the operating pressure of our storage facilities (affected in varying degree, depending on the type of storage cavern, by total volume of working and base gas, and temperature);

- a variety of commercial decisions we make from time to time in connection with the management and operation of our storage facilities. Examples include, without limitation, decisions with respect to matters such as (i) the aggregate amount of commitments we are willing to make with respect to wheeling, injection, and withdrawal services, which could exceed our capabilities at any given time for various reasons, (ii) the timing of scheduled and unplanned maintenance or repairs, which can impact equipment availability and capacity, (iii) the schedule for and rate at which we conduct opportunistic leaching activities at our facilities in connection with the expansion of existing salt caverns, which can impact the amount of storage capacity we have available to satisfy our customers requests, (iv) the timing and aggregate volume of any base gas park and/or loan transactions we consummate, which can directly affect the operating pressure of our storage facilities and (v) the amount of compression capacity and other gas handling equipment that we install at our facilities to support gas wheeling, injection and withdrawal activities; and

• adverse operating conditions due to hurricanes, extreme weather events or conditions, and operational problems or issues with third-party pipelines, storage or production facilities.

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

Risks Inherent in an Investment in Us

Cost reimbursements due to our general partner may be substantial and will reduce our cash available for distribution to unitholders.

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

Table of Contents

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

Because distributions on our common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of the general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

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

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

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

Unitholders may not be able to remove our general partner even if they wish to do so.

Our general partner manages and operates the Partnership. Unlike the holders of common stock in a corporation, unitholders will have only limited voting rights on matters affecting our business. Unitholders have no right to elect the general partner or the directors of the general partner on an annual or any other basis.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have little practical ability to remove our general partner or otherwise change its management. Our general partner may not be removed except upon the vote of the holders of at least 662/3% of our outstanding units (including units held by our general partner or its affiliates). Because the owners of our general partner, along with directors and executive officers and their affiliates, own a significant percentage of our outstanding common units, the removal of our general partner would be difficult without the consent of both our general partner and its affiliates.

In addition, the following provisions of our partnership agreement may discourage a person or group from attempting to remove our general partner or otherwise change our management:

- generally, if a person acquires 20% or more of any class of units then outstanding other than from our general partner or its affiliates, the units owned by such person cannot be voted on any matter; and

- limitations upon the ability of unitholders to call meetings or to acquire information about our operations, as well as other limitations upon the unitholders ability to influence the manner or direction of management.

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

We may issue additional common units without unitholder approval, which would dilute a unitholder s existing ownership interests.

Our general partner may cause us to issue an unlimited number of common units without unitholder approval (subject to applicable NYSE rules). We may also issue at any time an unlimited number of equity securities ranking junior or senior to the common units without unitholder approval (subject to applicable NYSE rules). The issuance of additional common units or other equity securities of equal or senior rank may have the following effects:

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

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

In addition, our preferred units are convertible into common units at any time after January 28, 2018 by the holders of such units, or under certain circumstances, at our option. If a substantial portion of the preferred units were converted into common units, common unitholders could experience significant dilution. In addition, if holders of such converted preferred units were to dispose of a substantial portion of these common units in the public market, whether in a single transaction or series of transactions, it could adversely affect the market price for our common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

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

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

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

Under Delaware law, a unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the control of our business.

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner. Our partnership agreement allows the general partner to incur obligations on our behalf that are expressly non-recourse to the general partner. The general partner has entered into such limited recourse obligations in most instances involving payment liability and intends to do so in the future.

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

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

These conflicts may include the following:

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

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

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

Table of Contents

with any of its affiliates on behalf of us. Agreements or contracts between us and our general partner (and its affiliates) are not necessarily the result of arms length negotiations; and

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

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

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

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

Risks Related to an Investment in Our Debt Securities

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

Our debt securities are effectively subordinated to claims of our secured creditors and to any existing and future indebtedness and other obligations of our subsidiaries, including trade payables, other than subsidiaries that may guarantee our debt securities in the future. In the event of the insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up of the business of a subsidiary, other than a subsidiary that may guarantee our debt securities in the future, creditors of that subsidiary would generally have the right to be paid in full before any distribution is made to us or the holders of our debt securities.

Our leverage may limit our ability to borrow additional funds, comply with the terms of our indebtedness or capitalize on business opportunities.

Our leverage is significant in relation to our partners capital. At December 31, 2015, the principal amount of our total outstanding long-term debt was approximately $10.5 billion, and the principal amount of our total outstanding short-term debt was approximately $1.0 billion. We will be prohibited from making cash distributions during an event of default under any of our indebtedness. Various limitations in our credit facilities and other debt instruments may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

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

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

The ability to transfer our debt securities may be limited by the absence of an organized trading market.

We do not currently intend to apply for listing of our debt securities on any securities exchange or stock market. The liquidity of any market for our debt securities will depend on the number of holders of those debt securities, the interest of securities dealers in making a market in those debt securities and other factors. Accordingly, we can give no assurance as to the development, continuation or liquidity of any market for the debt securities.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

We are a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the ownership interests in our subsidiaries. As a result, our ability to make required payments on our debt securities depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit facilities and applicable state partnership laws and other laws and regulations. Pursuant to our credit facilities, we may be required to establish cash reserves for the future payment of principal and interest on the amounts outstanding under our credit facilities. If we are unable to obtain the funds necessary to pay the principal amount at maturity of our debt securities, or to repurchase our debt securities upon the occurrence of a change of control, we may be required to adopt one or more alternatives, such as a refinancing of our debt securities. We can give no assurance that we would be able to refinance our debt securities.

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

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

- to provide for the proper conduct of our business and the businesses of our operating partnerships (including reserves for future capital expenditures and for our anticipated future credit needs);

- to provide funds for distributions to our unitholders and the general partner for any one or more of the next four calendar quarters; or

- to comply with applicable law or any of our loan or other agreements.

Although our payment obligations to our unitholders are subordinate to our payment obligations to debtholders, the value of our units will decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue equity to recapitalize.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of additional entity-level taxation by individual states. If the Internal Revenue Service (IRS) were to treat us as a corporation for federal income tax purposes or if we become subject to additional amounts of entity-level taxation for state or foreign tax purposes, it would reduce the amount of cash available to pay distributions and our debt obligations.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. A publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless it satisfies a qualifying income requirement, as defined in Section 7704 of the Internal Revenue Code of 1986, as amended. The IRS issued proposed regulations on which activities give rise to qualifying income within the meaning of Section 7704 on May 5, 2015, but are not yet final. However, finalized regulations could modify the amount of our gross income that we are able to treat as qualifying income for the purposes of the qualifying income requirement. Based on our current operations we believe that we are treated as a partnership rather than a corporation for such purposes; however, a change in our business could cause

Table of Contents

us to be treated as a corporation for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

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

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

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

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

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

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

The Bipartisan Budget Act of 2015 (H.R. 1315) (Act), effective for partnership tax years beginning after December 31, 2017, repeals the partnership audit rules of the Tax Equity and Fiscal Responsibility Act of 1982 (TEFRA) and replaces the TEFRA provisions with new provisions that allow for the IRS to assess and collect taxes associated with audit adjustments, referred to as an imputed underpayment , at the partnership entity level rather than the partner level in the year the partnership adjustment is made, the adjustment year , as opposed to the year the adjustment relates, the reviewed year . The imputed underpayment is calculated using the highest tax rate in effect for the reviewed year. The implications of an imputed underpayment are that current partners could be liable for a liability of former partners. If an audit adjustment did result in a material imputed underpayment the partnership would need to determine whether to pay the imputed underpayment or to avail itself of one of three alternative provisions under the Act that can shift the partnership level tax liability back onto the prior tax year partners. The first alternative, an opt-out election, is not available to us as a publicly traded partnership because we do not meet the criteria of 100 or fewer partners. The second alternative would require the partnership to submit audit adjustment information to the affected partners and to the IRS as well as ensure amended return compliance by our partners within 270 days after receipt of the proposed audit adjustment. From an administrative standpoint, considering the number of our partners, as a publicly traded partnership, the second alternative is not a viable option to us. The third

Table of Contents

alternative is an election by us that would require the partnership, not later than 45 days after the date of the notice of final partnership adjustment, to furnish to each affected partner and to the IRS a statement of each partner s share of any adjustment to income, gain, loss, deduction, or credit. Under this alternative, reviewed year partners calculate their share of additional tax due and pay the additional amount with their respective current year individual tax returns. An election under this provision, however, because the reviewed year is older increases the applicable imputed underpayment interest rate by two percentage points. If we are required to pay taxes, penalties and interest as the result of audit adjustments, cash available for distribution to our unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited taxable year.

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

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

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

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

The IRS has made no determination as to our status as a partnership for federal income tax purposes or as to any other matter affecting us. The IRS or CRA may adopt positions that differ from the positions we take or challenge the inter-country allocations we make. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS or CRA may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS or CRA and any incremental taxes required to be paid will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution or debt service.

Our unitholders may be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income that could be different in amount than the cash we distribute, they will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

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

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

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

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

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

Because we cannot match transferors and transferees of common units, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders tax returns.

Our unitholders will likely be subject to state, local and non-U.S. taxes and return filing requirements in states and jurisdictions where they do not live as a result of investing in our units.

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

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

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

A successful IRS challenge to these methods or allocations could adversely affect the amount, character, and timing of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions.

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a short seller to cover a short sale of common units) may be considered as having disposed of those common units. If so, he would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income,

Table of Contents

gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units may be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

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

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

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

None.

Item 3. ***Legal Proceedings***

Loss Contingencies General

To the extent we are able to assess the likelihood of a negative outcome for a contingency, our assessments of such likelihood range from remote to probable. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue an undiscounted liability equal to the estimated amount. If a range of probable loss amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then we accrue an undiscounted liability equal to the minimum amount in the range. In addition, we estimate legal fees that we expect to incur associated with loss contingencies and accrue those costs when they are material and probable of being incurred.

We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when the likelihood of loss is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material to our consolidated financial statements, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss.

Legal Proceedings General

In the ordinary course of business, we are involved in various legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to fully protect us from losses arising from current or future legal proceedings.

Taking into account what we believe to be all relevant known facts and circumstances, and based on what we believe to be reasonable assumptions regarding the application of those facts and circumstances to existing laws and regulations, we do not believe that the outcome of the legal proceedings in which we are currently involved (including those described below) will, individually or in the aggregate, have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Environmental General

Although over the course of the last several years we have made significant investments in our maintenance and integrity programs, and have hired additional personnel in those areas, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline, rail, storage and other facility operations. These releases can result from accidents or from unpredictable man-made or natural forces and may reach surface water bodies, groundwater aquifers or other sensitive environments. Damages and liabilities associated with any such releases from our existing or future assets could be significant and could have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

We record environmental liabilities when environmental assessments and/or remedial efforts are probable and the amounts can be reasonably estimated. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We do not discount our environmental remediation liabilities to present value. We also record environmental liabilities assumed in business combinations based on the estimated fair value of the environmental obligations caused by past operations of the acquired company. We record receivables for amounts recoverable from insurance or from third parties under indemnification agreements in the period that we determine the costs are probable of recovery.

Environmental expenditures that pertain to current operations or to future revenues are expensed or capitalized consistent with our capitalization policy for property and equipment. Expenditures that result from the remediation of an existing condition caused by past operations and that do not contribute to current or future profitability are expensed.

At December 31, 2015, our estimated undiscounted reserve for environmental liabilities (including liabilities related to the Line 901 incident, as discussed further below) totaled $185 million, of which $81 million was classified as short-term and $104 million was classified as long-term. At December 31, 2014, our estimated undiscounted reserve for environmental liabilities totaled $82 million, of which $13 million was classified as short-term and $69 million was classified as long-term. The short- and long-term environmental liabilities referenced above are reflected in Accounts payable and accrued liabilities and Other long-term liabilities and deferred credits, respectively, on our Consolidated Balance Sheets. At December 31, 2015 and 2014, we had recorded receivables totaling $161 million and $8 million, respectively, for amounts probable of recovery under insurance and from third parties under indemnification agreements, which are predominantly reflected in Trade accounts receivable and other receivables, net on our Consolidated Balance Sheets.

In some cases, the actual cash expenditures associated with these liabilities may not occur for three years or longer. Our estimates used in determining these reserves are based on information currently available to us and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing or future legal claims giving rise to additional liabilities. Therefore, although we believe that the reserve is adequate, actual costs incurred (which may ultimately include costs for contingencies that are currently not reasonably estimable or costs for contingencies where the likelihood of loss is currently believed to be only reasonably possible or remote) may be in excess of the reserve and may potentially have a material adverse effect on our consolidated financial condition, results of operations or cash flows.

Specific Legal, Environmental or Regulatory Matters

Line 901 Incident. In May 2015, we experienced a crude oil release from our Las Flores to Gaviota Pipeline (Line 901) in Santa Barbara County, California. A portion of the released crude oil reached the Pacific Ocean at Refugio State Beach through a drainage culvert. Following the release, we shut down the pipeline and initiated our emergency response plan. A Unified Command, which includes the United States Coast Guard, the EPA, the California Office of Spill Prevention and Response and the Santa Barbara Office of Emergency Management, was established for the response effort. Clean-up and remediation operations with respect to impacted shoreline and other areas has been determined by the Unified Command to be complete, subject to continued shoreline monitoring. The cause of the release remains under investigation. Our current worst case estimate of the amount of oil spilled, representing the maximum volume of oil that we believed could have been spilled based on relevant facts, data and information, is approximately 2,935 barrels.

As a result of the Line 901 incident, several governmental agencies and regulators have initiated investigations into the Line 901 incident, various claims have been made against us and a number of lawsuits have been filed against us. We may be subject to additional claims, investigations and lawsuits, which could materially impact the liabilities and costs we currently expect to incur as a result of the Line 901 incident. Set forth below is a brief summary of actions and matters that are currently pending:

On May 21, 2015, we received a corrective action order from the United States Department of Transportation s Pipeline and Hazardous Materials Safety Administration (PHMSA), the governmental agency that has jurisdiction over the operation of Line 901 as well as over a second stretch of pipeline extending from Gaviota Pump Station in Santa Barbara County to Emidio Pump Station in Kern County, California (Line 903), requiring us to shut down, purge, review, remediate and test Line 901. On June 3, 2015, the corrective action order was amended to require us to take additional corrective actions with respect to both Lines 901 and 903, and on November 13, 2015, the corrective action order was further amended to require the purge and shutdown of Line 903 between Gaviota and Pentland (as amended, the CAO). Among other requirements, the CAO also obligates us to conduct a root cause failure analysis with respect to Line 901 and present remedial work plans and restart plans to PHMSA prior to returning Line 901 and 903 to service; the CAO also imposes a pressure restriction on Line 903 and requires us to take other specified actions with respect to both Lines 901 and 903. We intend to continue to comply with the CAO and to cooperate with any other governmental investigations relating to or arising out of the release. Excavation and removal of the affected section of the pipeline was completed on May 28, 2015. No timeline

Table of Contents

has been established for the restart of Line 901 or Line 903. On February 17, 2016, PHMSA issued a Preliminary Factual Report of the Line 901 failure, which contains PHMSA s preliminary findings regarding factual information about the events leading up to the accident and the technical analysis that has been conducted to date. By virtue of its statutory authority, PHMSA has the power and authority to impose fines and penalties on us and cause civil or criminal charges to be brought against us. While to date PHMSA has not imposed any such fines or penalties or pursued any such civil or criminal charges with respect to the Line 901 release, there can be no assurance that such fines or penalties will not be imposed upon us, or that such civil or criminal charges will not be brought against us, in the future.

On September 11, 2015, we received a Notice of Probable Violation and Proposed Compliance Order from PHMSA arising out of its inspection of Lines 901 and 903 in August, September and October of 2013 (the 2013 Audit NOPV). The 2013 Audit NOPV alleges that the Partnership committed probable violations of various federal pipeline safety regulations by failing to document, or inadequately documenting, certain activities. On October 12, 2015, the Partnership filed a response to the 2013 Audit NOPV. To date, PHMSA has not issued a final order with respect to the 2013 Audit NOPV, nor has it assessed any fines or penalties with respect thereto; however, we cannot provide any assurances that any such fines or penalties will not be assessed against us.

In late May of 2015, on behalf of the EPA, the United States Attorney for the Department of Justice, Central District of California, Environmental Crimes Section (DOJ) began an investigation into whether there were any violations of federal criminal statutes in connection with the Line 901 incident, including potential violations of the federal Clean Water Act. We are cooperating with the DOJ s investigation by responding to their requests for documents and access to our employees. The DOJ has already spoken to several of our employees and has expressed an interest in talking to other employees; consistent with the terms of our governing organizational documents, we are funding our employees defense costs, including the costs of separate counsel engaged to represent such individuals. In addition to the DOJ, the California Attorney General s Office and the District Attorney s Office for the County of Santa Barbara are also investigating the Line 901 incident to determine whether any applicable state or local laws have been violated. On August 26, 2015, we also received a Request for Information from the EPA relating to Line 901 and we are in the process of responding to such request. While to date no civil or criminal charges with respect to the Line 901 release have been brought against PAA or any of its affiliates, officers or employees by PHMSA, DOJ, EPA, California Attorney General or Santa Barbara County District Attorney, and no fines or penalties have been imposed by such governmental agencies, there can be no assurance that such fines or penalties will not be imposed upon us, our officers or our employees, or that such civil or criminal charges will not be brought against us, our officers or our employees in the future, whether by those or other governmental agencies.

Shortly following the Line 901 incident, we established a claims line and encouraged any parties that were damaged by the release to contact us to discuss their damage claims. We have received a number of claims through the claims line and we are processing those claims as we receive them. In addition, we have also had seven class action lawsuits filed against us, all of which have been administratively consolidated into a single proceeding in the United States District Court for the Central District of California. In general, the plaintiffs are seeking to establish different classes of claimants that have allegedly been damaged by the release, including potential classes such as persons that derive a significant portion of their income through commercial fishing and harvesting activities in the waters adjacent to Santa Barbara County or from businesses that are dependent on marine resources from Santa Barbara County, retail businesses located in historic downtown Santa Barbara, certain owners of oceanfront and/or beachfront property on the Pacific Coast of California, and other classes of individuals and businesses that were allegedly impacted by the release.

There have also been two securities law class action lawsuits filed on behalf of certain purported investors in the Partnership and/or PAGP against the Partnership, PAGP and/or certain of their respective officers, directors and underwriters. Both of these lawsuits have been consolidated into a single proceeding in the United States District Court for the Southern District of Texas. In general, these lawsuits allege that the various defendants violated securities laws by misleading investors regarding the integrity of the Partnership s pipelines and related facilities through false and misleading statements, omission of material facts and concealing of the true extent of the spill. The plaintiffs claim unspecified damages as a result of the reduction in value of their investments in the Partnership and PAGP, which they attribute to the alleged wrongful acts of the defendants. The Partnership and PAGP, and the other defendants, deny the allegations in these lawsuits and intend to respond accordingly. Consistent with and subject to the terms of our governing organizational documents (and to the extent applicable, insurance policies), we are indemnifying and funding the defense costs of our officers and directors in connection with these lawsuits; we are also indemnifying and funding the defense costs of our underwriters pursuant to the terms of the underwriting agreements we previously entered into with such underwriters.

In addition, three unitholder derivative lawsuits have been filed by certain purported investors in the Partnership against the Partnership, certain of its affiliates and certain officers and directors. Two of these lawsuits were filed in the United States District Court for the Southern District of Texas and the other was filed in State District Court in Harris County, Texas. In general, these lawsuits allege that the various defendants breached their fiduciary duties, engaged in gross mismanagement and made false and misleading statements, among other similar allegations, in connection with their management and oversight of the Partnership during the period of time leading up to and following the Line 901 release. The plaintiffs claim that the Partnership suffered unspecified damages as a result of the actions of the various defendants and seek to hold the defendants liable for such damages, in addition to other remedies. The defendants deny the allegations in these lawsuits and intend to respond accordingly. Consistent with and subject to the terms of our governing organizational documents (and to the extent applicable, insurance policies), we are indemnifying and funding the defense costs of our officers and directors in connection with these lawsuits.

In addition to the foregoing, as the responsible party for the Line 901 incident we are liable for various costs and for certain natural resource damages under the Oil Pollution Act, and we also have exposure to the payment of additional fines, penalties and costs under other applicable federal, state and local laws, statutes and regulations. To the extent any such costs are reasonably estimable, we have included an estimate of such costs in the loss accrual described below.

Taking the foregoing into account, as of December 31, 2015, we estimate that the aggregate total costs we have incurred or will incur with respect to the Line 901 incident will be approximately $269 million, which estimate includes actual and projected emergency response and clean-up costs, natural resource damage assessments and certain third party claims settlements, as well as estimates for fines, penalties and certain legal fees. This estimate considers our prior experience in environmental investigation and remediation matters and available data from, and in consultation with, our environmental and other specialists, as well as currently available facts and presently enacted laws and regulations. We have made assumptions for (i) the expected number of days that monitoring services will be required, (ii) the duration of the natural resource damage assessment and the ultimate amount of damages determined, (iii) the resolution of certain third party claims and lawsuits, but excluding claims and lawsuits with respect to which losses are not probable and reasonably estimable, and excluding future claims and lawsuits, (iv) the determination and calculation of fines and penalties, but excluding fines and penalties that are not probable and reasonably estimable and (v) the nature, extent and cost of legal services that will be required in connection with all lawsuits, claims and other matters requiring legal or expert advice associated with the Line 901 incident. Our estimate does not include any lost revenue associated with the shutdown of Line 901 or 903 and does not include any liabilities or costs that are not reasonably estimable at this time or that relate to contingencies where we currently regard the likelihood of loss as being only reasonably possible or remote. We believe we have accrued adequate amounts for all probable and reasonably estimable costs; however, this estimate is subject to uncertainties associated with the assumptions that we have made. For example, the amount of time it takes for us to resolve all of the current and future lawsuits, claims and investigations that relate to the Line 901 incident could turn out to be significantly longer than we have assumed, and as a result the costs we incur for legal services could be significantly higher than we have estimated. In addition, with respect to fines and penalties, the ultimate amount of any fines and penalties assessed against us depends on a wide variety of factors, many of which are not estimable at this time. Where fines and penalties are probable and estimable, we have included them in our estimate, although such estimates could turn out to be wrong. Accordingly, our assumptions and estimates may turn out to be inaccurate and our total costs could turn out to be materially higher; therefore, we can provide no assurance that we will not have to accrue significant additional costs in the future with respect to the Line 901 incident.

We have accrued such estimate of aggregate total costs to Field operating costs on our Consolidated Statement of Operations. As of December 31, 2015, we had a remaining undiscounted gross liability of $116 million related to this event, the majority of which is presented as a current liability in Accounts payable and accrued liabilities on our Consolidated Balance Sheets. We maintain insurance coverage, which is subject to certain exclusions and deductibles, in the event of such environmental liabilities. Subject to such exclusions and deductibles, we believe that our coverage is adequate to cover the current estimated total emergency response and clean-up costs, claims settlement costs and remediation costs and we believe that this coverage is also adequate to cover any potential increase in the estimates for these costs that exceed the amounts currently identified. Through December 31, 2015, we had collected, subject to customary reservations, $31 million out of the approximate $186 million of release costs that we believe are probable of recovery from insurance carriers, net of deductibles. We recovered an additional $69 million of proceeds from insurance carriers in January 2016. As of December 31, 2015, we have recognized a receivable of approximately $155 million for the portion of the release costs that we believe is probable of recovery from insurance, net of deductibles and amounts already collected. A majority of this receivable has been recognized as a current asset in Trade accounts receivable and other receivables, net on our Consolidated Balance Sheets with the offset reducing Field operating costs on our Consolidated Statement of Operations. We have substantially completed the clean-up and remediation efforts, excluding long-term site monitoring activities; however, we expect to make payments for additional costs associated with restoration and monitoring of the area, as well as natural resource damage assessment, legal, professional and regulatory costs, in addition to fines and penalties, during future periods.

MP29 Release. On July 10, 2015, we experienced a crude oil release of approximately 100 barrels at our Pocahontas Pump Station near the border of Bond and Madison Counties in Illinois, approximately 40 miles from St. Louis, Missouri. The Pocahontas Station is part of the Capwood pipeline that runs from our Patoka Station to Wood River, Illinois. A portion of the released crude oil was contained within our Pocahontas facility, but some of the released crude oil entered a nearby waterway where it was contained with booms. On July 14, 2015, PHMSA issued a corrective action order requiring us to take various actions in response to the release, including remediation, reporting and other actions. As of December 18, 2015, we had submitted all requested information and reports required by the corrective action order and are currently awaiting PHMSA s comment or approval. On August 10, 2015, we received a Notice of Violation from the Illinois Environmental Protection Agency (the Agency) alleging violations relating to the release and outlining the activities recommended by the Agency to resolve the alleged violations, including the completion of an investigation and various remediation activities. The Agency approved a work plan describing remediation activities proposed for remaining hydrocarbons at Pocahontas Station and affected waterways. Remediation activities under this work plan have effectively been completed, and on December 17, 2015, we entered into a Compliance Commitment Agreement with the Agency, which provides the framework for final completion and documentation of the remediation effort. To date, no fines or penalties have been assessed in this matter; however, it is possible that fines and penalties could be assessed in the future. In connection with this incident, we have also had one class action lawsuit filed against us in the United States District Court for the Southern District of Illinois, which was subsequently voluntarily dismissed by the plaintiff. We estimate that the aggregate total costs associated with this release will be less than $10 million.

Cushing Tank Cathodic Protection. On May 22, 2015, PHMSA issued a Final Order relating to an April 2013 Notice of Probable Violation and Proposed Compliance Order alleging that we did not maintain adequate cathodic protection for certain tanks at our Cushing Terminal. In its 2013 Notice of Probable Violation, PHMSA maintained that the proprietary cathodic protection system utilized by us for certain of our storage tanks at our Cushing, Oklahoma facility was not contemplated by applicable regulations. In response to the notice, we provided extensive documentation and supporting information regarding the effectiveness of the technology we were utilizing, including past communications with PHMSA regarding the topic. At a hearing in August 2013, we gave a formal presentation on the technology, provided empirical data confirming its effectiveness and also had a third party corrosion expert witness speak to the effectiveness of the technology. Almost two years later, PHMSA issued the Final Order and Compliance Order dated May 22, 2015 ruling against our position, assessing a penalty of $102,900 and specifying certain corrective actions to be completed by us. We chose not to further contest this matter and paid the penalty on June 5, 2015.

In the Matter of Bakersfield Crude Terminal LLC et al. On April 30, 2015, the EPA issued a Finding and Notice of Violation (NOV) to Bakersfield Crude Terminal LLC, our subsidiary, for alleged violations of the Clean Air Act, as amended. The NOV, which cites 10 separate rule violations, questions the validity of construction and operating permits issued to our Bakersfield rail unloading facility in 2012 and 2014 by the San Joaquin Valley Air Pollution Control District (the SJV District). We believe we fully complied with all applicable regulatory requirements and that the permits issued to us by the SJV District are valid. To date, no fines or penalties have been assessed in this matter; however, it is possible that fines and penalties could be assessed in the future.

Mesa to Basin Pipeline. On January 6, 2016, PHMSA issued a Notice of Probable Violation and Proposed Civil Penalty relating to an approximate 500 barrel release of crude oil that took place on January 1, 2015 on our Mesa to Basin 12 pipeline in Midland, Texas. PHMSA conducted an accident investigation and reviewed documentation related to the incident, and concluded that we had committed probable violations of certain pipeline safety regulations. In the Notice, PHMSA maintains that we failed to carry out our written damage prevention program and to follow our pipeline excavation/ditching and backfill procedures on four separate occasions, and that such failures resulted in outside force damage that led to the January 1, 2015 release. PHMSA s compliance officer has recommended that we be assessed a civil penalty of $190,000. We have formally responded to PHMSA regarding this matter, but at this point we can provide no assurance regarding the final disposition of this matter or the final amount of any civil penalties.

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

Kemp River Pipeline Releases. In May and June 2013, two separate releases were discovered on our Kemp River pipeline in Northern Alberta, Canada that, in the aggregate, resulted in the release of approximately 700 barrels of condensate and light crude oil. Clean-up and remediation activities are being conducted in cooperation with the applicable regulatory agencies. Final investigation by the Alberta Energy Regulator is not complete. To date, no charges, fines or penalties have been assessed against PMC with respect to these releases; however, it is possible that fines or penalties may be assessed against PMC in the future. We estimate that the aggregate clean-up and remediation costs associated with these releases will be $15 million. Through December 31, 2015, we spent $9 million in connection with clean-up and remediation activities.

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

Environmental Remediation

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

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

Assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified. We have in the past experienced and in the future likely will experience releases of crude oil into the environment from

Table of Contents

our pipeline and storage operations. We also may discover environmental impacts from past releases that were previously unidentified.

Insurance

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

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

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

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

Not applicable.

Table of Contents

PART II

Item 5. *Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities*

Our common units are listed and traded on the New York Stock Exchange (NYSE) under the symbol PAA. As of February 12, 2016, the closing market price for our common units was $17.32 per unit and there were approximately 185,000 record holders and beneficial owners (held in street name). As of February 12, 2016, there were 397,730,991 common units outstanding.

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

The following table sets forth high and low sales prices for our common units and the cash distributions declared per common unit for the periods indicated:

	Common Unit Price Range		Cash
	High	**Low**	**Distributions (1)**
2015			
4th Quarter	$ 34.98	$ 17.83	$ 0.700
3rd Quarter	$ 44.29	$ 26.71	$ 0.700
2nd Quarter	$ 51.71	$ 43.00	$ 0.695
1st Quarter	$ 52.70	$ 45.81	$ 0.685
2014			
4th Quarter	$ 59.75	$ 43.61	$ 0.675
3rd Quarter	$ 61.09	$ 55.98	$ 0.660
2nd Quarter	$ 60.05	$ 54.54	$ 0.645
1st Quarter	$ 55.30	$ 49.25	$ 0.630

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

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

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

Recent Sales of Unregistered Securities

On January 28, 2016, we completed the private placement of 61,030,127 Series A Convertible Preferred Units representing limited partner interests in us (the preferred units) for a cash purchase price of $26.25 per preferred unit (the Issue Price), resulting in total net proceeds to us, after deducting offering expenses and the 2% transaction fee due to the purchasers and including our 2% general partner s proportionate contribution, of approximately $1.6 billion. The purchasers of such preferred units included affiliates of EnCap Investments, L.P., EnCap Flatrock Midstream, The Energy Minerals Group, Kayne Anderson Capital Advisors, L.P., First Reserve Advisors, L.L.C. and Stonepeak Partners LP, in addition to Massachusetts Mutual Life Insurance Company and Kaiser Foundation Hospitals (collectively, the Purchasers).

The preferred units are a new class of equity security that ranks senior to all classes or series of equity securities in us with respect to distribution rights and rights upon liquidation. The holders of the preferred units will receive quarterly distributions, subject to customary anti-dilution adjustments, equal to an annual rate of 8% of the Issue Price ($2.10 per unit annualized). With respect to any quarter ending on or prior to December 31, 2017 (the Initial Distribution Period), we may elect to pay distributions on the preferred units in additional preferred units, in cash or a combination of both. With respect to any quarter ending after the Initial Distribution Period, we must pay distributions on preferred units in cash. For a period of 30 days following (a) the fifth anniversary of the issue date of the preferred units and (b) each subsequent anniversary of the issue date, the holders of preferred units, acting by majority vote, may make a one-time election to reset the preferred unit distribution rate to equal the then applicable rate of ten-year

Table of Contents

U.S. Treasury Securities plus 5.85% (the Distribution Rate Reset). If the holders of preferred units have exercised the Distribution Rate Reset, then, at any time following 30 days after the sixth anniversary of the issue date of the preferred units, we may redeem all or any portion of the outstanding preferred units in exchange for cash, common units (valued at 95% of the volume-weighted average price of our common units for the 30 trading day period ending on the fifth trading day immediately prior to the date of such redemption) or a combination of cash and common units at a redemption price equal to 110% of the Issue Price, plus any accrued and unpaid distributions.

The Purchasers may convert their preferred units, generally on a one-for-one basis and subject to customary anti-dilution adjustments, at any time after the second anniversary of the issuance date (or prior to a liquidation), in whole or in part, so long as any partial conversion is not for less than $100 million (calculated based on the closing price of our common units on the trading day immediately prior to the notice of conversion) or such lesser amount, if such conversion relates to all of a holder s remaining preferred units. We may convert the preferred units at any time (but not more often than once per quarter) after the third anniversary of the issuance date, in whole or in part, if the closing price of our common units is greater than 150% of the Issue Price for the preceding 20 trading days, so long as any partial conversion is not for less than $500 million (calculated based on the closing trading price of common units on the trading day immediately prior to the notice of conversion) or such lesser amount, if such conversion relates to all of the then outstanding preferred units. The preferred units will vote on an as-converted basis with our common units and will have certain other class voting rights with respect to any amendment to our partnership agreement that would adversely affect any rights, preferences or privileges of the preferred units.

In addition, upon certain events involving a change of control, each holder of preferred units may elect to (a) convert its preferred units to common units at the then applicable conversion rate, (b) if we are not the surviving entity (or if we are the surviving entity, but our common units will cease to be listed), require us to use commercially reasonable efforts to cause the surviving entity in any such transaction to issue a substantially equivalent security (or convert into common units based on a specified formula, if we are unable to cause such substantially equivalent securities to be issued), (c) if we are the surviving entity, continue to hold the preferred units or (d) require us to redeem the preferred units at a price per preferred unit equal to 101% of the Issue Price, plus accrued and unpaid distributions.

The private placement of the preferred units was undertaken in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereof.

Cash Distribution Policy

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

- provide for the proper conduct of our business;
- comply with applicable law or any partnership debt instrument or other agreement; or

- provide funds for distributions to unitholders and the general partner in respect of any one or more of the next four quarters.

In addition to distributions on its 2% general partner interest, our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, our general partner is entitled, without duplication and except for the agreed upon adjustments discussed below, to 15% of amounts we distribute in excess of $0.2250 per unit, 25% of the amounts we distribute in excess of $0.2475 per unit and 50% of amounts we distribute in excess of $0.3375 per unit.

Although not required to do so, in response to past requests by our management in connection with our acquisition activities, our general partner has, from time to time, agreed to reduce the amounts due to it as incentive distributions. Such modifications were implemented with a view toward enhancing our competitiveness for such acquisitions and managing the overall cost of equity capital while achieving an appropriate balance between short-term and long-term accretion to our limited partners and the holders of our general partner interest and IDRs. During 2015, 2014 and 2013, our general partner s incentive distributions were reduced by approximately $22 million, $23 million and $15 million, respectively. These reductions were agreed to in connection with our BP NGL Acquisition and the PNG Merger. In addition, our general partner has agreed to reduce the amount of its incentive distribution by $5.0 million per quarter in 2016 and $3.75 million per quarter thereafter. See Note 10 to our Consolidated Financial Statements for

Table of Contents

further discussion of the PNG Merger. In connection with our January 2016 private placement of preferred units, our general partner agreed to further modify its IDRs such that when the preferred units convert into common units, the IDRs associated with the resulting common units will only participate in distribution growth above an annualized distribution level of $2.80 per converted common unit. See Note 10 to our Consolidated Financial Statements for further discussion of the preferred unit issuance.

During 2015, we paid $590 million to our general partner, net of IDR reductions. Additionally, on February 12, 2016, we paid a quarterly distribution of $0.70 per common unit applicable to the fourth quarter of 2015, and in connection therewith, approximately $155 million was paid to our general partner, net of IDR reductions. See Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner.

Under the terms of the agreements governing our debt, we are prohibited from declaring or paying any distribution to unitholders if a default or event of default (as defined in such agreements) exists. No such default has occurred. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit Agreements, Commercial Paper Program and Indentures.

Under the terms of our partnership agreement, our preferred units rank senior to all classes or series of equity securities in us with respect to distribution rights.

Issuer Purchases of Equity Securities

We did not repurchase any of our common units during the fourth quarter of 2015, and we do not have any announced or existing plans to repurchase any of our common units other than potential repurchases consistent with past practice in providing units for relatively small vestings of phantom units under our long-term incentive plans (LTIP).

Item 6. *Selected Financial Data*

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2015, 2014, 2013, 2012 and 2011 and for the years then ended. The selected financial data should be read in conjunction with the Consolidated Financial Statements, including the notes thereto, and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

Amounts for 2011 through 2014 have been retroactively restated to reflect the impact of our adoption of revised debt issuance costs guidance issued by the Financial Accounting Standards Board (FASB). See Note 2 to our Consolidated Financial Statements for additional information.

	Year Ended December 31,				
	2015	2014	2013	2012	2011

	(in millions, except per unit data)									
Statement of operations data:										
Total revenues	$	23,152	$	43,464	$	42,249	$	37,797	$	34,275
Operating income	$	1,262	$	1,799	$	1,738	$	1,434	$	1,306
Net income	$	906	$	1,386	$	1,391	$	1,127	$	994
Net income attributable to PAA	$	903	$	1,384	$	1,361	$	1,094	$	966
Per unit data:										
Basic net income per common unit	$	0.78	$	2.39	$	2.82	$	2.41	$	2.46
Diluted net income per common unit	$	0.77	$	2.38	$	2.80	$	2.40	$	2.44
Declared distributions per common unit (1)	$	2.76	$	2.55	$	2.33	$	2.11	$	1.95
Balance sheet data (at end of period):										
Property and equipment, net	$	13,474	$	12,272	$	10,819	$	9,643	$	7,740
Total assets	$	22,288	$	22,198	$	20,320	$	19,196	$	15,355
Long-term debt	$	10,375	$	8,704	$	6,675	$	6,281	$	4,494
Total debt	$	11,374	$	9,991	$	7,788	$	7,367	$	5,173
Partners capital	$	7,939	$	8,191	$	7,703	$	7,146	$	5,974
Other data:										
Net cash provided by operating activities	$	1,344	$	2,004	$	1,954	$	1,240	$	2,365

Table of Contents

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(in millions, except per unit data)				
Net cash used in investing activities	$ (2,530)	$ (3,296)	$ (1,653)	$ (3,392)	$ (2,020)
Net cash provided by/(used in) financing activities	$ 814	$ 1,657	$ (281)	$ 2,151	$ (345)
Capital expenditures:					
Acquisition capital	$ 105	$ 1,099	$ 19	$ 2,286	$ 1,404
Expansion capital	$ 2,170	$ 2,026	$ 1,622	$ 1,185	$ 531
Maintenance capital	$ 220	$ 224	$ 176	$ 170	$ 120

	Year Ended December 31,				
	2015	2014	2013	2012	2011
Volumes (2) (3)					
Transportation segment (average daily volumes in thousands of barrels per day):					
Tariff activities	4,340	3,952	3,595	3,373	2,942
Trucking	113	127	117	106	105
Transportation segment total volumes	4,453	4,079	3,712	3,479	3,047
Facilities segment:					
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	100	95	94	90	70
Rail load / unload volumes (average volumes in thousands of barrels per day)	210	231	221		
Natural gas storage (average monthly working capacity in billions of cubic feet)	97	97	96	84	71
NGL fractionation (average volumes in thousands of barrels per day)	103	96	96	79	14
Facilities segment total volumes (average monthly volumes in millions of barrels)	126	121	120	106	82
Supply and Logistics segment (average daily volumes in thousands of barrels per day):					
Crude oil lease gathering purchases	943	949	859	818	742
NGL sales	223	208	215	182	103
Waterborne cargos	2		4	3	21
Supply and Logistics segment total volumes	1,168	1,157	1,078	1,003	866

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(1) Represents cash distributions declared and paid during the year presented. Our general partner is entitled, directly or indirectly, to receive 2% proportional distributions, as well as incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. See Note 10 to our Consolidated Financial Statements for further discussion regarding our distributions.

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

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

Table of Contents

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

Introduction

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

Our discussion and analysis includes the following:

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

Executive Summary

Company Overview

We own and operate midstream energy infrastructure and provide logistics services for crude oil, NGL, natural gas and refined products. We own an extensive network of pipeline transportation, terminalling, storage, and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries and are managed through three operating segments: Transportation, Facilities and Supply and Logistics. See Results of Operations Analysis of Operating Segments for further discussion.

Overview of Operating Results, Capital Investments and Other Significant Activities

Primarily as a result of advances in drilling and completion techniques and their application to a number of large-scale shale and resource plays, which occurred contemporaneously with attractive petroleum prices, during the approximately three year period through the end of 2014, U.S. crude oil and liquids production in the lower 48 states increased rapidly. Additionally, during this period, the crude oil market experienced high levels of volatility in location and quality differentials as a result of the confluence of regional infrastructure constraints in North America, rapid and unexpected changes in crude oil qualities, international supply issues, and regional downstream operating issues. During 2014 (albeit to a lesser degree than previous years), these market conditions had a positive impact on our profitability as our business strategy and asset base positioned us to capitalize on opportunities created by the volatile environment. However, the combination during such period of surging North American liquids production, relatively flat liquids production for the rest of the world and relatively modest growth in global liquids demand led to a supply imbalance, which in turn led to a significant and rapid reduction in petroleum prices during the second half of 2014 and throughout 2015.

While we believe that our business model and asset base have minimal direct exposure to petroleum prices, our performance is influenced by certain differentials and overall North American production levels, which in turn are impacted by major price movements. The meaningful decrease in crude oil price levels during the second half of 2014 and throughout 2015 relative to the levels experienced during 2013 and the first half of 2014 have led many producers, including North American producers, to significantly scale back capital programs. As a result, during 2015, the rate of growth of North American crude oil production slowed significantly and began to decrease in some areas as producers have taken rigs out of service and deferred completions at an increased rate. The slowdown in North American production coupled with increases in infrastructure led to a compression of basis differentials in a number of locations. This transitioning crude oil market created a challenging environment for our business model and asset base in 2015. We recognized net income attributable to PAA of $903 million in 2015 as compared to net income attributable to PAA of $1.384 billion recognized in 2014. The year-over-year decrease was driven by:

Table of Contents

- Lower operating results, primarily from our Supply and Logistics segment, as increased competition and compressed differentials from the market conditions discussed above drove lower unit margins in this part of our business. See further discussion of our segment operating results in the Results of Operations Analysis of Operating Segments section below;

- Costs and lost revenue associated with the Line 901 incident; and

- Higher depreciation and amortization expense and interest expense associated with our growing asset base and related financing activities; partially offset by

- Lower income tax expense resulting from the deferred income tax impact associated with fluctuations in the derivative mark-to-market valuation in our Canadian operations.

We executed a $2.2 billion capital program during 2015. We expect the majority of the capital invested will contribute to growth in our fee-based Transportation and Facilities segments in future years. We completed multiple financings that enabled us to fund our 2015 capital expansion activities, including raising an aggregate of approximately $2.1 billion of long-term debt and equity capital. In addition, we paid approximately $1.7 billion of cash distributions to our common unitholders and general partner during 2015.

Acquisitions and Capital Projects

We completed a number of acquisitions and capital projects in 2015, 2014 and 2013 that have impacted our results of operations. The following table summarizes our expenditures for acquisition capital, expansion capital and maintenance capital for the periods indicated (in millions):

	Year Ended December 31, 2015	2014	2013
Acquisition capital (1) (2)	$ 105	$ 1,099	$ 19
Expansion capital (3)	2,170	2,026	1,622
Maintenance capital (3)	220	224	176
	$ 2,495	$ 3,349	$ 1,817

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

(2) Excludes the PNG Merger completed on December 31, 2013, as we historically consolidated PNG into our financial statements for financial reporting purposes in accordance with GAAP. As consideration for the PNG Merger, we issued approximately 14.7 million PAA common units with a value of approximately $760 million. See Note 10 to our Consolidated Financial Statements for further discussion of the PNG Merger.

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

Table of Contents

Acquisitions

Acquisitions are financed using a combination of equity and debt, including borrowings under our commercial paper program or credit facilities and the issuance of senior notes. Businesses acquired impact our results of operations commencing on the closing date of each acquisition. Our acquisition and capital expansion activities are discussed further in Liquidity and Capital Resources. Information regarding acquisitions completed in 2015, 2014 and 2013 is set forth in the table below (in millions):

Acquisition	Effective Date		Acquisition Price	Operating Segment
2015 Total	Various	$	105	Transportation and Facilities
BridgeTex Acquisition (50% interest) (1)	11/14/2014	$	1,088	Transportation
Other	Various		11	Facilities
2014 Total		$	1,099	
2013 Total (2)	09/01/2013	$	19	Transportation

(1) We account for our 50% interest in BridgeTex under the equity method of accounting. See Note 7 to our Consolidated Financial Statements for further discussion of our equity method investments.

(2) Excludes the PNG Merger completed on December 31, 2013, as we historically consolidated PNG into our financial statements for financial reporting purposes in accordance with GAAP. As consideration for the PNG Merger, we issued approximately 14.7 million PAA common units with a value of approximately $760 million. See Note 10 to our Consolidated Financial Statements for further discussion of the PNG Merger.

Expansion Capital Projects

Our 2015 projects primarily included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2015, 2014 and 2013 projects (in millions):

Projects		2015		2014		2013
Permian Basin Area Projects (1)	$	470	$	378	$	59
Rail Terminal Projects (2)		294		239		149
Fort Saskatchewan Facility Projects / NGL Line (1)		272		142		73
Red River Pipeline (Cushing to Longview) (1)		143				
Cactus Pipeline (1)		134		350		64
Saddlehorn Pipeline (1) (3)		103				
Eagle Ford JV Project (1) (4)		93		117		60

Cowboy Pipeline (Cheyenne to Carr) (1)		47				
Eagle Ford Area Projects (5)		45		10		86
St. James Terminal Expansions (1)		45		25		51
Cushing Terminal Expansions (1)		39		13		38
Diamond Pipeline (1) (4)		6		29		3
Mississippian Lime Pipeline				58		163
Pascagoula Pipeline				26		125
Other Projects		479		639		751
Total	$	2,170	$	2,026	$	1,622

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(1) These projects will continue into 2016. See Liquidity and Capital Resources Acquisitions, Capital Expenditures and Distributions Paid to Our Unitholders, General Partner and Noncontrolling Interests 2016 Capital Projects.

(2) Includes railcar purchases, as well as rail projects near St. James, LA; Tampa, CO; Bakersfield, CA; Carr, CO; Manitou, ND; Van Hook, ND; Yorktown, VA; and Kerrobert, Canada rail projects.

(3) Represents contributions related to our 40% investment interest in Saddlehorn.

(4) Represents contributions related to our 50% investment interest.

Table of Contents

(5) Includes pipeline, tankage and condensate stabilization.

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

We currently expect to spend approximately $1.5 billion for expansion capital in 2016. See Liquidity and Capital Resources Acquisitions, Capital Expenditures and Distributions Paid to Our Unitholders, General Partner and Noncontrolling Interests 2016 Capital Projects and Outlook for additional information.

Critical Accounting Policies and Estimates

Critical Accounting Policies

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

Critical Accounting Estimates

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

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

Purchase and Sales Accruals. We routinely make accruals based on estimates for certain components of our revenues and purchases and related costs due to the timing of compiling billing information, receiving third-party information and reconciling our records with those of third parties. Where applicable, these accruals are based on nominated volumes expected to be purchased, transported and subsequently sold. Uncertainties involved in these estimates include levels of production at the wellhead, access to certain qualities of crude oil, pipeline capacities and delivery times, utilization of truck fleets to transport volumes to their destinations, weather, market conditions and other forces beyond our control. These estimates are generally associated with a portion of the last month of each reporting period. For the year ended December 31, 2015, we estimate that approximately 2% of annual revenues and purchases and related costs were recorded using sales and purchase estimates. Accordingly, a hypothetical variance of 10% from both of these estimates, either up or down in tandem, would impact annual revenues, purchases and related costs, operating income and net income attributable to PAA by less than 1% on an annual basis. Although the resolution of these uncertainties has not historically had a material impact on our reported results of operations or financial condition, because of the high volume, low margin nature of our business, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Variances from estimates are reflected in the period actual results become known, typically in the month following the estimate.

Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets. In accordance with FASB guidance regarding business combinations, with each acquisition, we allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. If the initial accounting for the business combination is incomplete when the combination occurs, an estimate will be recorded. Any subsequent adjustments to this estimate, if material, will be recognized retroactive to the date of acquisition. With exception to acquisitions of equity method investments, we also expense the transaction costs as incurred in connection with each acquisition. In

Table of Contents

addition, we are required to recognize intangible assets separately from goodwill. Intangible assets with finite lives are amortized over their estimated useful life as determined by management. Goodwill and intangible assets with indefinite lives are not amortized but instead are periodically assessed for impairment.

Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, contracts and industry expertise, involves professional judgment and is ultimately based on acquisition models and management s assessment of the value of the assets acquired and, to the extent available, third party assessments. Impairment testing entails estimating future net cash flows relating to the business, based on management s estimate of future revenues, future cash flows and market conditions including pricing, demand, competition, operating costs and other factors, such as weighted average cost of capital. Uncertainties associated with these estimates include changes in production decline rates, production interruptions, fluctuations in refinery capacity or product slates, economic obsolescence factors in the area and potential future sources of cash flow. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Further, significant negative variances in the assumptions and estimates utilized in our forecasts, such as a continued decline in petroleum commodity prices or a sustained multi-year low petroleum commodity price environment that results in lower volumes and cash flows or further increases in our weighted average cost of capital assumption, could result in reporting unit carrying values in excess of fair values. See Note 6 to our Consolidated Financial Statements for a further discussion of goodwill.

Fair Value of Derivatives. The fair value of a derivative at a particular period end does not reflect the end results of a particular transaction, and will most likely not reflect the gain or loss at the conclusion of a transaction. We reflect estimates for these items based on our internal records and information from third parties. The valuations of our derivatives that are exchange traded are based on market prices on the applicable exchange on the last day of the period. For our derivatives that are not exchange traded, the estimates we use are based on indicative broker quotations or an internal valuation model. Our valuation models utilize market observable inputs such as price, volatility, correlation and other factors and may not be reflective of the price at which they can be settled due to the lack of a liquid market. Less than 1% of total annual revenues are based on estimates derived from internal valuation models. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. See Note 11 to our Consolidated Financial Statements for a discussion regarding our derivatives and risk management activities.

Accruals and Contingent Liabilities. We record accruals or liabilities for, among other things, environmental remediation, natural resource damage assessments, governmental fines and penalties, potential legal claims and fees for legal services associated with loss contingencies, and bonuses. Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Our estimates are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our environmental remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment, the duration of the natural resource damage assessment and the ultimate amount of damages determined, the determination and calculation of fines and penalties, the possibility of existing legal claims giving rise to additional claims and the nature, extent and cost of legal services that will be required in connection with lawsuits, claims and other matters. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. A hypothetical variance of 5% in our aggregate estimate for the accruals and contingent liabilities discussed above would have an impact on earnings of up to approximately $14 million. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

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

We recognized equity-indexed compensation expense of $27 million, $98 million and $116 million in 2015, 2014 and 2013, respectively, related to awards granted under our various equity-indexed compensation plans. A hypothetical variance of 5% in our

Table of Contents

aggregate estimate for the equity-indexed compensation expense would have an impact on net income attributable to PAA of less than 1%. See Note 15 to our Consolidated Financial Statements for a discussion regarding our equity-indexed compensation plans.

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

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

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

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

We did not recognize any material impairment of long-lived assets during the three years ending December 31, 2015. See Note 5 to our Consolidated Financial Statements for further discussion regarding impairments.

Allowance for Doubtful Accounts. We perform credit evaluations of our customers and grant credit based on past payment history, financial conditions and anticipated industry conditions. Customer payments are regularly monitored and a provision for doubtful accounts is established based on specific situations and overall industry conditions. Our history of bad debt losses has been minimal (less than $2 million in the aggregate over the years ended December 31, 2015, 2014 and 2013) and generally limited to specific customer circumstances; however, credit risks can change suddenly and without notice. See Note 2 to our Consolidated Financial Statements for additional discussion.

Inventory Valuations. Inventory, including long-term inventory, primarily consists of crude oil, NGL and natural gas and is valued at the lower of cost or market, with cost determined using an average cost method within specific inventory pools. At the end of each reporting period, we assess the carrying value of our inventory and use estimates and judgment when making any adjustments necessary to reduce the carrying value to net realizable value. Among the uncertainties that impact our estimates are the applicable quality and location differentials to include in our net realizable value analysis. Additionally, we estimate the upcoming liquidation timing of the inventory. Changes in assumptions made as to the timing of a sale can materially impact net realizable value. During the years ended December 31, 2015, 2014 and 2013, we recorded charges of $117 million, $289 million and $7 million, respectively, related to the valuation adjustment of our crude oil, NGL and natural gas inventory due to declines in prices. See Note 4 to our Consolidated Financial Statements for further discussion regarding inventory.

Recent Accounting Pronouncements

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

Table of Contents

Results of Operations

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

	Year Ended December 31,			Favorable/(Unfavorable) Variance			
				2015-2014		2014-2013	
	2015	2014	2013	$	%	$	%
Transportation segment profit	$ 917	$ 925	$ 729	$ (8)	(1)%	$ 196	27%
Facilities segment profit	579	584	616	(5)	(1)%	(32)	(5)%
Supply and Logistics segment profit	381	782	822	(401)	(51)%	(40)	(5)%
Total segment profit	1,877	2,291	2,167	(414)	(18)%	124	6%
Depreciation and amortization	(432)	(384)	(365)	(48)	(13)%	(19)	(5)%
Interest expense, net	(432)	(348)	(313)	(84)	(24)%	(35)	(11)%
Other income/(expense), net	(7)	(2)	1	(5)	(250)%	(3)	(300)%
Income tax expense	(100)	(171)	(99)	71	42%	(72)	(73)%
Net income	906	1,386	1,391	(480)	(35)%	(5)	%
Net income attributable to noncontrolling interests	(3)	(2)	(30)	(1)	(50)%	28	93%
Net income attributable to PAA	$ 903	$ 1,384	$ 1,361	$ (481)	(35)%	$ 23	2%
Basic net income per common unit	$ 0.78	$ 2.39	$ 2.82	$ (1.61)	(67)%	$ (0.43)	(15)%
Diluted net income per common unit	$ 0.77	$ 2.38	$ 2.80	$ (1.61)	(68)%	$ (0.42)	(15)%
Basic weighted average common units outstanding	394	367	341	27	7%	26	8%
Diluted weighted average common units outstanding	396	369	343	27	7%	26	8%

Non-GAAP Financial Measures

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

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

Table of Contents

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

	Year Ended December 31,			Favorable/(Unfavorable) Variance			
				2015-2014		2014-2013	
	2015	2014	2013	$	%	$	%
Net income	$ 906	$ 1,386	$ 1,391	$ (480)	(35)%	$ (5)	%
Add:							
Interest expense, net	432	348	313	84	24%	35	11%
Income tax expense	100	171	99	(71)	(42)%	72	73%
Depreciation and amortization	432	384	365	48	13%	19	5%
EBITDA	$ 1,870	$ 2,289	$ 2,168	$ (419)	(18)%	$ 121	6%
Selected Items Impacting Comparability of EBITDA							
Gains/(losses) from derivative activities net of inventory valuation adjustments (1)	$ (110)	$ 243	$ (59)	$ (353)	(145)%	$ 302	512%
Long-term inventory costing adjustments (2)	(99)	(85)		(14)	(16)%	(85)	N/A
Equity-indexed compensation expense (3)	(27)	(56)	(63)	29	52%	7	11%
Net gain/(loss) on foreign currency revaluation (4)	21	(13)	(1)	34	262%	(12)	(1,200)%
Line 901 incident (5)	(83)			(83)	N/A		N/A
Other (6)			(1)		N/A	1	100%
Selected Items Impacting Comparability of EBITDA	$ (298)	$ 89	$ (124)	$ (387)	(435)%	$ 213	172%
EBITDA	$ 1,870	$ 2,289	$ 2,168	$ (419)	(18)%	$ 121	6%
Selected Items Impacting Comparability of EBITDA	298	(89)	124	387	435%	(213)	(172)%
Adjusted EBITDA	$ 2,168	$ 2,200	$ 2,292	$ (32)	(1)%	$ (92)	(4)%
Adjusted EBITDA	$ 2,168	$ 2,200	$ 2,292	$ (32)	(1)%	$ (92)	(4)%
Interest expense (7)	(417)	(334)	(297)	(83)	(25)%	(37)	(12)%
Maintenance capital (8)	(220)	(224)	(176)	4	2%	(48)	(27)%
Current income tax expense	(84)	(71)	(100)	(13)	(18)%	29	29%
Equity earnings in unconsolidated entities, net of distributions	31	(3)	(10)	34	1,133%	7	70%
Distributions to noncontrolling interests (9)	(4)	(3)	(38)	(1)	(33)%	35	92%
Implied DCF (10)	$ 1,474	$ 1,565	$ 1,671	$ (91)	(6)%	$ (106)	(6)%
Less: Distributions paid (9)	(1,714)	(1,469)	(1,215)				
DCF Excess/(Shortage) (11)	$ (240)	$ 96	$ 456				

(1) We use derivative instruments for risk management purposes and our related processes include

specific identification of hedging instruments to an underlying hedged transaction. Although we identify an underlying transaction for each derivative instrument we enter into, there may not be an accounting hedge relationship between the instrument and the underlying transaction. In the course of evaluating our results of operations, we identify the earnings that were recognized during the period related to derivative instruments for which the identified underlying transaction does not occur in the current period and exclude the related gains and losses in determining Adjusted EBITDA. We also exclude the impact of corresponding inventory valuation adjustments, as applicable. See Note 11 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities.

(2) We carry approximately 5 million barrels of crude oil and NGL inventory that is comprised of minimum working inventory requirements in third-party assets and other working inventory that is needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future. Therefore,

Table of Contents

we classify this inventory as long-term on our balance sheet and do not hedge the inventory with derivative instruments (similar to linefill in our own assets). We treat the impact of changes in the average cost of the long-term inventory (that result from fluctuations in market prices) as a selected item impacting comparability. During 2015 and 2014, crude oil and NGL prices decreased significantly resulting in inventory valuation adjustments. See Note 4 to our Consolidated Financial Statements for additional inventory disclosures.

(3) Our total equity-indexed compensation expense includes expense associated with awards that will or may be settled in units and awards that will or may be settled in cash. The awards that will or may be settled in units are included in our diluted earnings per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a selected item impacting comparability as the dilutive impact of the outstanding awards is included in our diluted earnings per unit calculation and the majority of the awards are expected to be settled in units. The portion of compensation expense associated with awards that are certain to be settled in cash is not considered a selected item impacting comparability. See Note 15 to our Consolidated Financial Statements for a comprehensive discussion regarding our equity-indexed compensation plans.

(4) During 2015, 2014 and 2013, there were fluctuations in the value of the Canadian dollar (CAD) to the U.S. dollar (USD), resulting in gains and losses that were not related to our core operating results for the period and were thus classified as selected items impacting comparability. See Note 11 to our Consolidated Financial Statements for further discussion regarding our currency exchange rate risk hedging activities.

(5) Includes costs related to the Line 901 incident that occurred in May 2015, net of amounts we believe are probable of recovery from insurance. See Note 16 to our Consolidated Financial Statements for additional information.

(6) Includes other immaterial selected items impacting comparability.

(7) Excludes certain non-cash items impacting interest expense such as amortization of debt issuance costs and terminated interest rate swaps.

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

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

(10) Including costs of $83 million related to the Line 901 incident that occurred in May 2015, Implied DCF would have been $1,391 million for the year ended December 31, 2015. See Note 16 to our Consolidated Financial Statements for additional information regarding the Line 901 incident.

(11) DCF shortages are funded from previously established reserves, cash on hand or from borrowings under our credit facilities or commercial paper program. Excess DCF is retained to establish reserves for future distributions, capital expenditures and other partnership purposes.

Analysis of Operating Segments

We manage our operations through three operating segments: Transportation, Facilities and Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 18 to our Consolidated Financial Statements for a definition of segment profit (including an explanation of why this is a performance measure) and a reconciliation of segment profit to net income attributable to PAA.

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

Table of Contents

general and administrative overhead expenses between segments based on management s assessment of the business activities for the period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period. We believe that the estimates with respect to these allocations are reasonable.

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

Transportation Segment

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

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

				Favorable/(Unfavorable) Variance			
Operating Results (1)	**Year Ended December 31,**			**2015-2014**		**2014-2013**	
(in millions, except per barrel data)	**2015**	**2014**	**2013**	**$**	**%**	**$**	**%**
Revenues							
Tariff activities	$ 1,439	$ 1,447	$ 1,293	$ (8)	(1)%	$ 154	12%
Trucking	155	208	205	(53)	(25)%	3	1%
Total transportation revenues	1,594	1,655	1,498	(61)	(4)%	157	10%
Costs and Expenses							
Trucking costs	(108)	(151)	(147)	43	28%	(4)	(3)%
Field operating costs (2)	(652)	(560)	(528)	(92)	(16)%	(32)	(6)%
Equity-indexed compensation expense - operations	(5)	(15)	(18)	10	67%	3	17%
Segment general and administrative expenses (2) (3)	(89)	(83)	(101)	(6)	(7)%	18	18%
Equity-indexed compensation expense - general and administrative	(6)	(29)	(39)	23	79%	10	26%
Equity earnings in unconsolidated entities	183	108	64	75	69%	44	69%
Segment profit	$ 917	$ 925	$ 729	$ (8)	(1)%	$ 196	27%
Maintenance capital	$ 144	$ 165	$ 123	$ 21	13%	$ (42)	(34)%
Segment profit per barrel	$ 0.56	$ 0.62	$ 0.54	$ (0.06)	(10)%	$ 0.08	15%

				Favorable/(Unfavorable) Variance			
Average Daily Volumes	**Year Ended December 31,**			**2015-2014**		**2014-2013**	
(in thousands of barrels per day) (4)	**2015**	**2014**	**2013**	**Volumes**	**%**	**Volumes**	**%**
Tariff activities volumes							
Crude oil pipelines (by region):							

Permian Basin (5)	1,849	1,512	1,299	337	22%	213	16%
South Texas / Eagle Ford (5)	306	227	102	79	35%	125	123%
Western	215	260	247	(45)	(17)%	13	5%
Rocky Mountain (5)	440	426	398	14	3%	28	7%
Gulf Coast	532	492	442	40	8%	50	11%
Central	413	450	405	(37)	(8)%	45	11%
Canada	392	399	384	(7)	(2)%	15	4%
Crude oil pipelines	4,147	3,766	3,277	381	10%	489	15%
NGL pipelines	193	186	250	7	4%	(64)	(26)%
Refined products pipelines			68		N/A	(68)	(100)%
Tariff activities total volumes	4,340	3,952	3,595	388	10%	357	10%
Trucking volumes	113	127	117	(14)	(11)%	10	9%
Transportation segment total volumes	4,453	4,079	3,712	374	9%	367	10%

Table of Contents

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

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

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

(4) 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.

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

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

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

Net Operating Revenues, Equity Earnings and Volumes. As noted in the table above, our total Transportation segment revenues, net of trucking costs, decreased for the year ended December 31, 2015 compared to the year ended December 31, 2014, but increased for the year ended December 31, 2014 compared to the year ended December 31, 2013. Equity earnings in unconsolidated entities and average daily volumes increased year-over-year for each of the comparative periods presented. The following table presents the net revenue and equity earnings variances by type of revenue, product and region for the comparative periods presented:

	Favorable/(Unfavorable) Variance 2015 - 2014	Favorable/(Unfavorable) Variance 2014 - 2013

(in millions)	Net Revenues	Equity Earnings	Net Revenues	Equity Earnings
Tariff activities:				
Permian Basin region	$ 75	$ 52	$ 66	$ 9
South Texas / Eagle Ford region	12	19	24	28
Western region	(24)		3	
Canada	(16)		40	
NGL pipelines	(1)		(14)	
Refined products pipelines			(28)	
Other (including pipeline loss allowance revenue)	(54)	4	63	7
Tariff activities total	(8)	75	154	44
Trucking	(10)		(1)	
Transportation segment total	$ (18)	$ 75	$ 153	$ 44

- Tariff activities

- *Permian Basin region.* The increase in revenues for 2015 over 2014 was primarily driven by results from (i) our Cactus pipeline, which was placed in service in April 2015, and (ii) higher volumes related to increased production, primarily associated with the expansion of our pipeline system in the Delaware Basin.

Revenues increased for 2014 over 2013 primarily due to (i) higher volumes related to increased production and new pipeline connections and (ii) higher pumpover movements at our Basin pipeline terminal.

The increase in equity earnings for each of the comparative periods presented was driven by earnings from our interest in BridgeTex, which we acquired in November 2014.

Table of Contents

- *South Texas / Eagle Ford region.* Revenues increased for each of the comparative periods due to higher volumes driven by increased production and the extension of our gathering system.

Equity earnings increased for each of the comparative periods presented due to higher earnings from our interest in Eagle Ford Pipeline LLC, primarily driven by higher throughput on the Eagle Ford pipeline system. The higher throughput in 2015 compared to 2014 was due to a combination of (i) the connection to our Cactus pipeline in April 2015, (ii) the completion of an expansion of the pipeline system in August 2015 and (iii) increased crude oil production in the Eagle Ford region. The higher throughput for 2014 compared to 2013 was primarily due to increased crude oil production in the Eagle Ford region.

- *Western region.* Revenues and volumes decreased for 2015 as compared to 2014 primarily due to pipeline downtime on our All American Pipeline associated with the Line 901 incident that occurred in the second quarter of 2015. See Note 16 to our Consolidated Financial Statements for additional information regarding this incident.

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

Revenues increased for 2014 over 2013 primarily due to (i) rate increases on certain of our pipelines and related system assets, (ii) additional revenues from a reclassification of certain storage facilities from our Facilities segment to our Transportation segment during the second quarter of 2014, (iii) higher revenues from our Rangeland and South Saskatchewan pipelines, as they were shut down in the second and third quarters of 2013 due to high river flow rates and flooding in the surrounding area and (iv) incremental volumes and revenues from our Wascana pipeline, which was reactivated during the second quarter of 2014 and was connected to our Bakken North pipeline system. Such increases were partially offset by unfavorable foreign exchange impacts of $16 million.

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

Revenues and volumes from our NGL pipelines decreased for 2014 as compared to 2013 primarily due to (i) the discontinuation of a capacity lease arrangement in the fourth quarter of 2013, (ii) the impact of netting joint venture related volumes to our share on a pipeline during 2014, which did not affect revenues and (iii) estimated unfavorable foreign exchange impacts of $7 million. Such unfavorable impacts were partially offset by higher revenues from our Co-Ed pipeline due to tariff rate increases and the shutdown of the pipeline in the second and third quarters of 2013 due to high river flow rates and flooding in the surrounding area.

- *Refined products pipelines.* We sold our refined products pipeline systems and related assets in 2013.

- *Other.* The variances for the comparative periods presented were primarily related to pipeline loss allowance revenue. Loss allowance revenue decreased by $62 million for 2015 compared to 2014 primarily due to a lower average realized price per barrel, partially offset by higher volumes. Loss allowance revenue increased by $46 million for 2014 over 2013 and was primarily driven by higher volumes.

- Trucking Net revenues from our trucking operations decreased for 2015 as compared to 2014 due to unfavorable foreign exchange impacts of $8 million and lower producer volumes.

Field Operating Costs. The increase in field operating costs (excluding equity-indexed compensation expense) for the year ended December 31, 2015 compared to the year ended December 31, 2014 was primarily due to estimated costs of $83 million recognized during 2015 associated with the Line 901 incident, net of amounts we believe are probable of recovery from insurance. See Note 16 to our Consolidated Financial Statements for additional information regarding this incident. The increase in field operating costs was also driven by (i) higher salary and related expenses and property tax expense primarily associated with new assets placed in service in 2015 and (ii) higher maintenance and repairs cost, partially offset by favorable foreign exchange impacts of $22 million.

Field operating costs (excluding equity-indexed compensation expense) increased during the year ended December 31, 2014 compared to the year ended December 31, 2013 primarily due to (i) a change in classification of $14 million of certain costs from general and administrative expenses, (ii) increased asset integrity spending, (iii) higher property tax expense due to capital expansion

Table of Contents

and (iv) higher utility costs associated with increased throughput volumes. Such increases were partially offset by a reduction in environmental remediation costs and an $11 million favorable foreign exchange impact.

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

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

Equity-Indexed Compensation Expense. A majority of our equity-indexed compensation awards (including the AAP Management Units) contain performance conditions contingent upon achieving certain distribution levels. For awards with performance conditions (such as distribution targets), expense is accrued over the service period only if the performance condition is considered probable of occurring. When awards with performance conditions that were previously considered improbable become probable, we incur additional expense in the period that our probability assessment changes. This is necessary to bring the accrued liability associated with these awards up to the level it would have been if we had been accruing for these awards since the grant date. At December 31, 2015, a distribution level of $2.90 per common unit was deemed probable of occurring in the reasonably foreseeable future (and was initially determined to be probable in the fourth quarter of 2014). Furthermore, a change in unit price impacts the fair value of our liability-classified awards. See Note 15 to our Consolidated Financial Statements for additional information regarding our equity-indexed compensation plans.

On a consolidated basis, equity-indexed compensation expense decreased by $71 million for the year ended December 31, 2015 compared to the year ended December 31, 2014, primarily due to the impact of the decrease in unit price during the year ended December 31, 2015 compared to the impact of the decrease in unit price during the year ended December 31, 2014. On a consolidated basis, equity-indexed compensation expense decreased by $18 million for the year ended December 31, 2014 compared to the year ended December 31, 2013 primarily due to the impact of the decrease in unit price during the year ended December 31, 2014 compared to the impact of the increase in unit price during the year ended December 31, 2013.

Maintenance Capital. Maintenance capital consists of capital expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets. The decrease in maintenance capital in 2015 compared to 2014 was primarily due to a reclassification of certain maintenance capital costs from our Facilities segment during the 2014 period. In addition, the decrease in maintenance capital was impacted by the depreciation of CAD relative to USD.

The increase in maintenance capital in 2014 compared to 2013 was primarily due to pipeline replacement projects and increased investments in pipeline integrity and a reclassification of certain maintenance capital costs from our Facilities segment during the 2014 period.

Facilities Segment

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

Table of Contents

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

Operating Results (1) **(in millions, except per barrel data)**	**Year Ended December 31,** **2015**	**2014**	**2013**	**Favorable/(Unfavorable) Variance** **2015-2014** **$**	**%**	**2014-2013** **$**	**%**
Revenues	$ 1,050	$ 1,127	$ 1,075	$ (77)	(7)%	$ 52	5%
Natural gas sales (2)			302		N/A	(302)	(100)%
Natural gas related storage costs	(24)	(55)	(16)	31	56%	(39)	(244)%
Natural gas sales costs (2)			(296)		N/A	296	100%
Field operating costs (3)	(377)	(404)	(362)	27	7%	(42)	(12)%
Equity-indexed compensation expense - operations		(4)	(2)	4	100%	(2)	(100)%
Segment general and administrative expenses (3) (4)	(65)	(60)	(63)	(5)	(8)%	3	5%
Equity-indexed compensation expense - general and administrative	(5)	(20)	(22)	15	75%	2	9%
Segment profit	$ 579	$ 584	$ 616	$ (5)	(1)%	$ (32)	(5)%
Maintenance capital	$ 68	$ 52	$ 38	$ (16)	(31)%	$ (14)	(37)%
Segment profit per barrel	$ 0.38	$ 0.40	$ 0.43	$ (0.02)	(5)%	$ (0.03)	(7)%

Volumes (5)	**Year Ended December 31,** **2015**	**2014**	**2013**	**Favorable/(Unfavorable) Variance** **2015-2014** **Volumes**	**%**	**2014-2013** **Volumes**	**%**
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	100	95	94	5	5%	1	1%
Rail load / unload volumes (average volumes in thousands of barrels per day)	210	231	221	(21)	(9)%	10	5%
Natural gas storage (average monthly working capacity in billions of cubic feet)	97	97	96		%	1	1%
NGL fractionation (average volumes in thousands of barrels per day)	103	96	96	7	7%		%
Facilities segment total volumes (average monthly volumes in millions of barrels) (6)	126	121	120	5	4%	1	1%

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

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

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

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

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

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

Table of Contents

year; (iii) natural gas storage working capacity divided by 6 to account for the 6:1 mcf of natural gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iv) NGL fractionation volumes multiplied by the number of days in the year and divided by the number of months in the year.

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

Net Operating Revenues and Volumes. As noted in the table above, our Facilities segment revenues, net of related costs, decreased by $46 million for the year ended December 31, 2015 compared to the year ended December 31, 2014, but increased by $7 million for the year ended December 31, 2014 over the comparable 2013 period. Total volumes increased for each of the comparative periods presented. Variances in net revenues and average monthly volumes between the comparative periods are discussed below:

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

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

- Natural Gas Storage Operations Net revenues decreased by $12 million for the year ended December 31, 2015 compared to the year ended December 31, 2014 and by $43 million for the year ended December 31, 2014 compared to the year ended December 31, 2013 primarily due to (i) declines in market rates for natural gas storage, which resulted in lower rates on new contracts replacing expiring contracts and (ii) reduced hub services opportunities. The 2014 period was further unfavorably impacted by costs incurred to manage deliverability requirements in conjunction with the extended period of severe cold weather experienced during the first quarter of 2014.

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

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

Revenues from our NGL storage, NGL fractionation and Canadian gas processing activities increased by $31 million for the year ended December 31, 2014 over the year ended December 31, 2013 largely driven by higher facility fee revenues due to rate increases at certain of our storage and fractionation facilities, partially offset by lower physical processing gains. Such increases were partially offset by estimated unfavorable foreign exchange impacts of $18 million. These impacts were largely offset in our Supply and Logistics segment results.

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

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

- Condensate Processing Revenues increased by $8 million for the year ended December 31, 2014 compared to 2013 due to the benefit from the start-up and subsequent expansion of our Gardendale condensate processing facility. Revenues were relatively consistent for the year ended December 31, 2015 compared to the year ended December 31, 2014.

Table of Contents

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

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

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

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

Maintenance Capital. The increase in maintenance capital in 2015 over 2014 was primarily due to various tank and facility projects and timing of equipment replacements, as well as the impact from a change in classification of certain maintenance capital costs to our Transportation segment in the 2014 period. The increase in maintenance capital in 2014 from 2013 is primarily due to the timing of maintenance projects for tanks and other facility assets, partially offset by a change in classification of certain maintenance capital costs to our Transportation segment in the 2014 period.

Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, as well as sales of NGL volumes purchased from suppliers and natural gas sales attributable to the activities performed by our natural gas storage commercial optimization group. Generally, our segment profit is impacted by (i) increases or decreases in our Supply and Logistics segment volumes (which consist of lease gathering crude oil purchase volumes, NGL sales volumes and waterborne cargos), (ii) demand for lease gathering services we provide producers and (iii) the overall volatility and strength or weakness of market conditions and the allocation of our assets among our various risk management strategies. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. 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.

Table of Contents

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

Operating Results (1) (2)	**Year Ended December 31,**			**Favorable/(Unfavorable) Variance**			
				2015-2014		**2014-2013**	
(in millions, except per barrel data)	**2015**	**2014**	**2013**	**$**	**%**	**$**	**%**
Revenues	$ 21,945	$ 42,150	$ 40,696	$ (20,205)	(48)%	$ 1,454	4%
Purchases and related costs (3)	(21,018)	(40,752)	(39,315)	19,734	48%	(1,437)	(4)%
Field operating costs (4)	(433)	(481)	(422)	48	10%	(59)	(14)%
Equity-indexed compensation expense - operations		(2)	(3)	2	100%	1	33%
Segment general and administrative expenses (4) (5)	(102)	(105)	(102)	3	3%	(3)	(3)%
Equity-indexed compensation expense - general and administrative	(11)	(28)	(32)	17	61%	4	13%
Segment profit	$ 381	$ 782	$ 822	$ (401)	(51)%	$ (40)	(5)%
Maintenance capital	$ 8	$ 7	$ 15	$ (1)	(14)%	$ 8	53%
Segment profit per barrel	$ 0.89	$ 1.85	$ 2.09	$ (0.96)	(52)%	$ (0.24)	(11)%

Average Daily Volumes	**Year Ended December 31,**			**Favorable (Unfavorable) Variance**			
				2015-2014		**2014-2013**	
(in thousands of barrels per day)	**2015**	**2014**	**2013**	**Volume**	**%**	**Volume**	**%**
Crude oil lease gathering purchases	943	949	859	(6)	(1)%	90	10%
NGL sales	223	208	215	15	7%	(7)	(3)%
Waterborne cargos	2		4	2	N/A	(4)	(100)%
Supply and Logistics segment total volumes	1,168	1,157	1,078	11	1%	79	7%

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(1) Revenues and costs include intersegment amounts.

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

(3) Purchases and related costs include interest expense (related to hedged inventory purchases) of $6 million, $12 million and $30 million for the years ended December 31, 2015, 2014 and 2013, respectively.

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

(5) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by

management and are based on the business activities that exist during each period.

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

	NYMEX WTI Crude Oil Price	
During the Year Ended December 31,	**Low**	**High**
2015	$ 35	$ 61
2014	$ 53	$ 107
2013	$ 87	$ 111

Because the commodities that we buy and sell are generally indexed to the same pricing indices for both sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. The absolute amount of our revenues and purchases decreased for the year ended December 31, 2015 compared to the year ended December 31, 2014 due to lower crude oil and NGL prices during the 2015 period. The increase of the absolute amount of our revenues and purchases for the year ended December 31,

Table of Contents

2014 over the year ended December 31, 2013 primarily resulted from higher crude oil volumes in the 2014 period, partially offset by lower crude oil prices relative to 2013, particularly in the fourth quarter.

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

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

Net Operating Revenues and Volumes. Our Supply and Logistics segment revenues, net of purchases and related costs, decreased by $471 million for the year ended December 31, 2015 as compared to the 2014 period, of which $389 million related to the mark-to-market impact of certain derivatives (see discussion and table below) and long-term inventory costing adjustments (see discussion below). For the 2014 period, segment revenues, net of purchases and related costs, increased by $17 million over the comparable 2013 period. The following summarizes the more significant items impacting the comparative periods:

- Crude Oil Operations Net revenues from our crude oil supply and logistics activities decreased for the year ended December 31, 2015 as compared to the year ended December 31, 2014 primarily due to (i) the compression of certain differentials during the 2015 period, which resulted in fewer opportunities to capture above-baseline margins as compared to 2014 and (ii) increased competition, largely due to overbuilt infrastructure in certain areas that has negatively impacted our lease gathering unit margins and volumes, most notably during the second half of 2015. However, such unfavorable results were partially offset by revenues from opportunities created by the contango market structure during 2015.

Net revenues from our crude oil supply and logistics activities increased slightly for 2014 as compared to 2013 primarily due to favorable impacts from the widening of certain differentials, most notably in the second and third quarters of 2014, that allowed for more opportunities to capture above-baseline margins as compared to 2013.

- NGL Operations Net revenues from our NGL operations increased for the year ended December 31, 2015 compared to the year ended December 31, 2014. The increase was primarily driven by higher margins due to the lower cost of inventory carried over from 2014 year end and higher sales volumes.

Net revenues from our NGL marketing operations decreased for the year ended December 31, 2014 as compared to the year ended December 31, 2013. This decrease was driven by higher NGL purchases and related costs in the 2014 periods, primarily due to a higher weighted average inventory cost and increased facility fees. Additionally, NGL margins were further impacted by less favorable market conditions, most notably during (i) the second quarter of 2014, as market pricing was stronger in the comparable 2013 period due to heating requirements during a winter season that extended into the second quarter and greater petrochemical demand for propane and (ii) the fourth quarter of 2014, due to less demand for crop drying as compared to the 2013 period.

- Natural Gas Storage Commercial Optimization During the first quarter of 2014, our natural gas storage commercial optimization activities were unfavorably impacted by costs incurred to manage deliverability requirements in conjunction with the extended period of severe cold weather experienced. We did not incur similar costs during 2015 or 2013.

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

	Year Ended December 31,			Variance	
	2015	2014	2013	2015-2014	2014-2013
Gains/(losses) from certain derivative activities, net of inventory valuation adjustments (1)	$ (114)	$ 261	$ (59)	$ (375)	$ 320

(1) Includes mark-to-market and other gains and losses resulting from certain derivative instruments that are related to underlying activities in another period (or the reversal of mark-to-market gains and losses from a prior period), gains

Table of Contents

and losses on certain derivatives that are related to investing activities (such as the purchase of linefill) and inventory valuation adjustments, as applicable. See Note 11 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities.

- Long-Term Inventory Costing Adjustments Our operating results are impacted by changes in the weighted average cost of our crude oil and NGL inventory pools that result from price movements during the periods. Such costing adjustments resulted in unfavorable impacts of $99 million and $85 million for the years ended December 31, 2015 and 2014, respectively, due to price decreases during each year. These costing adjustments related to long-term inventory necessary to meet our minimum inventory requirements in third-party assets and other working inventory that was needed for our commercial operations. We consider this inventory necessary to conduct our operations and we intend to carry this inventory for the foreseeable future.

- Foreign Exchange Impacts Our results are impacted by fluctuations in the value of CAD to USD, resulting in foreign exchange gains and losses on U.S. denominated net assets within our Canadian operations. The impact of such gains and losses resulted in a favorable variance of $38 million for 2015 compared to 2014 and an unfavorable variance of $16 million for 2014 to 2013.

Furthermore, the depreciation of CAD relative to USD resulted in lower net USD costs of approximately $41 million for 2015 compared to 2014 and by $15 million for 2014 compared to 2013. Such costs are primarily associated with intercompany facility fees and are largely offset in our Facilities segment results.

Field Operating Costs. The decrease in field operating costs (excluding equity-indexed compensation expenses) for the year ended December 31, 2015 compared to the year ended December 31, 2014 was primarily due to the decreased use of third party trucking services as pipeline expansion projects were placed into service.

The increase in field operating costs (excluding equity-indexed compensation expenses) for the year ended December 31, 2014 over the year ended December 31, 2013 was primarily due to an increase in trucking costs associated with higher lease gathering volumes.

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

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense increased during the 2015 period over the comparable 2014 period primarily due to various capital expansion projects completed during 2015, partially offset by favorable impacts from the depreciation of CAD relative to USD.

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

Interest Expense

Interest expense is primarily impacted by:

- our weighted average debt balances;
- the level and maturity of fixed rate debt and interest rates associated therewith;
- market interest rates and our interest rate hedging activities on floating rate debt; and
- interest capitalized on capital projects and included in purchases and related costs.

Table of Contents

The following table summarizes the components impacting the interest expense variance for the years ended December 31, 2015 and 2014 (in millions, except for percentages):

			Average LIBOR	Weighted Average Interest Rate (1)
Interest expense for the year ended December 31, 2013	$	313	0.2%	4.6%
Impact of issuance of senior notes (2) (5)		51		
Impact of interest included in purchases and related costs (3)		18		
Impact of retirement of senior notes (4)		(13)		
Impact of capitalized interest		(10)		
Other		(11)		
Interest expense for the year ended December 31, 2014	$	348	0.1%	4.5%
Impact of issuance of senior notes (5) (6)		88		
Impact of interest included in purchases and related costs (3)		6		
Impact of retirement of senior notes (7)		(9)		
Impact of capitalized interest		(9)		
Other		8		
Interest expense for the year ended December 31, 2015	$	432	0.2%	4.5%

(1) Excludes commitment and other fees.

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

(3) Interest costs attributable to borrowings for hedged inventory purchases are included in purchases and related costs in our Supply and Logistics segment profit as we consider interest on these borrowings a direct cost to storing the inventory. These costs were $6 million, $12 million and $30 million for the years ended December 31, 2015, 2014 and 2013, respectively.

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

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

(6) In August 2015, we completed the issuance of $1.0 billion of 4.65% senior notes due 2025.

(7) Our $150 million, 5.25% senior notes and $400 million, 3.95% senior notes matured in June 2015 and September 2015, respectively.

Other Income/(Expense), Net

Other income/(expense), net in each of the years ended December 31, 2015, 2014 and 2013 was primarily comprised of foreign currency gains or losses related to revaluations of CAD-denominated interest receivables associated with our intercompany notes and the impact of related foreign currency hedges.

Income Tax Expense

Income tax expense decreased for the year ended December 31, 2015 compared to the year ended December 31, 2014 primarily due to the deferred income tax impact associated with fluctuations in the derivative mark-to-market valuation in our Canadian operations during the 2015 and 2014 periods. This benefit was partially offset by an Alberta, Canada provincial tax rate increase of 2% enacted during the second quarter of 2015, as well as higher current income tax expense resulting from increased year-over-year taxable earnings from our Canadian operations. The 2015 period was also favorably impacted by the depreciation of CAD relative to USD.

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

Table of Contents

Outlook

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

However, the combination during such period of surging North American liquids production, relatively flat liquids production for the rest of the world and relatively modest growth in global liquids demand led to a supply imbalance, which in turn led to a significant and rapid reduction in petroleum prices. While we believe that our business model and asset base have minimal direct exposure to petroleum prices, our performance is influenced by certain differentials and overall North American production levels, which in turn are impacted by major price movements. The meaningful decrease in crude oil price levels during the second half of 2014 and throughout 2015 relative to the levels experienced during 2013 and the first half of 2014 have led many producers, including North American producers, to significantly scale back capital programs. As a result, during 2015, the rate of growth of North American crude oil production has slowed significantly and began to decrease in some areas as producers have taken rigs out of service and deferred completions at an increased rate. While we believe that the large North American resource base remains intact and will be developed, such production will likely take place at a slower pace and previously anticipated peak production levels will likely be reduced. The slowdown in North American production coupled with increases in infrastructure has led to a compression of basis differentials in a number of locations. This transitioning crude oil market presents challenges to our business model and asset base and will likely impact the rate of cash flow and distribution growth that we would have otherwise experienced over the next several years. In addition, increased competition and compressed differentials may drive lower volumes and lower unit margins in parts of our business, particularly our Supply and Logistics segment.

While we believe that these recent market developments will continue to slow down crude oil supply growth and contribute toward bringing the markets back to equilibrium, there can be no assurance that such equilibrium will be achieved or that we will not be negatively impacted by declining crude oil supply, low level of volatility or challenging capital markets conditions. Additionally, construction of additional infrastructure by us and our competitors will likely create excess takeaway capacity in certain areas at least for the near to medium term, which could further reduce unit margins in our various segments, and which may be exacerbated by declining levels of crude oil production. Finally, we cannot be certain that our expansion efforts will generate targeted returns or that any future acquisition activities will be successful. See Item 1A. Risk Factors Risks Related to Our Business.

Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) cash flow from operating activities as further discussed below in the section entitled Cash Flow from Operating Activities, (ii) borrowings under our credit facilities or commercial paper program and (iii) funds received from sales of equity and debt securities. Our primary cash requirements include, but are not limited to, (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil, NGL and other products and other expenses and interest payments on outstanding debt, (ii) expansion and maintenance activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on our long-term debt and (v) distributions to our unitholders and general partner. We generally expect to fund our short-term cash requirements through cash flow generated from operating activities and/or borrowings under our commercial paper program or credit facilities. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions and refinancing our long-term debt, through a variety of sources (either separately or in combination), which may include the sources mentioned above as funding for short-term needs and/or the issuance of additional equity or debt securities. As of December 31, 2015, we had a working capital deficit of $438 million and approximately $2.3 billion of liquidity available to meet our ongoing operating, investing and financing needs, subject to continued covenant compliance, as noted below (in millions):

Table of Contents

		As of December 31, 2015
Availability under senior unsecured revolving credit facility (1) (2)	$	1,583
Availability under senior secured hedged inventory facility (1) (2)		1,071
Availability under senior unsecured 364-day revolving credit facility		1,000
Amounts outstanding under commercial paper program		(1,368)
Subtotal		2,286
Cash and cash equivalents		27
Total	$	2,313

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(1) Represents availability prior to giving effect to amounts outstanding under our commercial paper program, which reduce available capacity under the facilities.

(2) Available capacity under the senior unsecured revolving credit facility and the senior secured hedged inventory facility was reduced by outstanding letters of credit of $17 million and $29 million, respectively.

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 our ongoing capital program and maintain a solid capital structure and significant liquidity, in January 2016, we 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.

We believe that we have, and will continue to have, the ability to access the commercial paper program and credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a materially adverse effect on our financial condition, results of operations or cash flows. Also, see Item 1A. Risk Factors for further discussion regarding such risks that may impact our liquidity and capital resources. Usage of the credit facilities, which provide the backstop for the commercial paper program, is subject to ongoing compliance with covenants. As of December 31, 2015, we were in compliance with all such covenants.

Cash Flow from Operating Activities

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

Cash flow from operating activities can be materially impacted by the storage of crude oil in periods of a contango market, when the price of crude oil for future deliveries is higher than current prices. In the month we pay for the stored crude oil, we borrow under our credit facilities or commercial paper program (or use cash on hand) to pay for the crude oil, which negatively impacts operating cash flow. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored crude oil. Similarly, the level of NGL and other product inventory stored and held for resale at period end affects our cash flow from operating activities.

In periods when the market is not in contango, we typically sell our crude oil during the same month in which we purchase it and we do not rely on borrowings under our credit facilities or commercial paper program to pay for the crude oil. During such market conditions, our accounts payable and accounts receivable generally move in tandem as we make payments and receive payments for the purchase and sale of crude oil in the same month, which is the month following such activity. In periods during which we build inventory, regardless of market structure, we may rely on our credit facilities or commercial paper program to pay for the inventory. In addition, we use derivative instruments to manage the risks associated with the purchase and sale of our commodities. Therefore, our cash flow from operating activities may be impacted by the margin deposit requirements related to our derivative activities and/or the timing of settlement of our derivative activities. For example, gains and losses from settled instruments that qualify as effective cash flow hedges are deferred in accumulated other comprehensive income/loss, but may impact operating cash flow in the period settled. See Note 11 to our Consolidated Financial Statements for a discussion regarding our derivatives and risk management activities.

Net cash provided by operating activities for the years ended December 31, 2015, 2014 and 2013 was approximately $1.3 billion, $2.0 billion and $1.95 billion, respectively, and primarily resulted from earnings from our operations. Additionally, as discussed further below, changes in our inventory levels during these years impacted our cash flow from operating activities.

During 2015, we increased the amount of our inventory; however, these volumetric increases were largely offset by lower prices for our inventory stored at the end of the year compared to prior year amounts.

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

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

Credit Agreements, Commercial Paper Program and Indentures

At December 31, 2015, we had four primary credit arrangements. These include a $1.6 billion senior unsecured revolving credit facility maturing in 2020, a $1.4 billion senior secured hedged inventory facility maturing in 2018 and a $1.0 billion, 364-day senior unsecured credit facility maturing in August 2016. Additionally, we have a $3.0 billion unsecured commercial paper program that is backstopped by our revolving credit facility and our hedged inventory facility. Our credit agreements (which impact our ability to access our commercial paper program because they provide the backstop that supports our short-term credit ratings) and the indentures governing our senior notes contain cross-default provisions. A default under our credit agreements would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with the provisions in our credit agreements, our ability to make distributions of available cash is not restricted. We were in compliance with the covenants contained in our credit agreements and indentures as of December 31, 2015.

Equity and Debt Financing Activities

Our financing activities primarily relate to funding expansion capital projects, acquisitions and refinancing of our debt maturities, as well as short-term working capital and hedged inventory borrowings related to our NGL business and contango market activities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under our credit facilities or commercial paper program, as well as payment of distributions to our unitholders and general partner.

Registration Statements. We periodically access the capital markets for both equity and debt financing. We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $2.0 billion of debt or equity securities (Traditional Shelf). All issuances of equity securities associated with our continuous offering program have been issued pursuant to the Traditional Shelf. At December 31, 2015, we had approximately $2.0 billion of unsold securities available under the Traditional Shelf. We also have access to a universal shelf registration statement (WKSI Shelf), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. Our March 2015 underwritten equity offering and our August 2015 senior notes issuance were conducted under our WKSI shelf. See Common Unit Issuances and Senior Notes below.

Table of Contents

Common Unit Issuances. The following table summarizes our issuance of common units during the three years ended December 31, 2015 (net proceeds in millions):

Year	Type of Offering	Units Issued		Net Proceeds (1) (2)
2015	Continuous Offering Program	1,133,904	$	59 (3)
2015	Underwritten Offering	21,000,000		1,062 (4)
2015 Total		**22,133,904**	**$**	**1,121**
2014 Total	**Continuous Offering Program**	**15,375,810**	**$**	**866** (3)
2013 Total	**Continuous Offering Program**	**8,644,807**	**$**	**477** (3)

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

(2) Amounts include our general partner s proportionate capital contributions of $22 million, $18 million and $9 million during 2015, 2014 and 2013, respectively.

(3) We pay commissions to our sales agents in connection with common unit issuances under our Continuous Offering Program. We paid $1 million, $9 million and $5 million of such commissions during 2015, 2014 and 2013, respectively. The net proceeds from these offerings were used for general partnership purposes.

(4) A portion of the net proceeds from such offering was used to repay borrowings under our commercial paper program and the remaining net proceeds were used for general partnership purposes, including expenditures for our 2015 capital program.

Preferred Unit Issuance. In January 2016, we completed the private placement of approximately 61.0 million preferred units at a price of $26.25 per unit resulting in total net proceeds to us, after deducting offering expenses and the 2% transaction fee due to the purchasers and including our 2% general partner s proportionate contribution, of approximately $1.6 billion. We intend to use the net proceeds for capital expenditures, repayment of debt and general partnership purposes.

The holders of the preferred units are entitled to receive quarterly distributions, subject to customary anti-dilution adjustments, of $0.525 per unit ($2.10 per unit annualized), commencing with the quarter ending March 31, 2016. With respect to any quarter ending on or prior to December 31, 2017, we may elect to pay distributions on the preferred units in additional preferred units, in cash or in a combination of both.

After two years, the preferred units are convertible at the purchasers option into common units on a one-for-one basis, subject to certain conditions, and are convertible at our option in certain circumstances after three years. See Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities Recent Sales of Unregistered Securities for additional information regarding the preferred units.

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

Year	Description	Maturity	Face Value	Gross Proceeds(1)	Net Proceeds(2)
2015	4.65% Senior Notes issued at 99.846% of face value (3)	October 2025	$ 1,000	$ 998	$ 990
2014	2.60% Senior Notes issued at 99.813% of face value (4)	December 2019	$ 500	$ 499	$ 495
2014	4.90% Senior Notes issued at 99.876% of face value (4)	February 2045	$ 650	$ 649	$ 643
2014	3.60% Senior Notes issued at 99.842% of face value (3)	November 2024	$ 750	$ 749	$ 743
2014	4.70% Senior Notes issued at 99.734% of face value (3)	June 2044	$ 700	$ 698	$ 691
2013	3.85% Senior Notes issued at 99.792% of face value (3)	October 2023	$ 700	$ 699	$ 693

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

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

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

(4) We used the net proceeds from this offering to repay outstanding borrowings under our commercial paper program (a portion of which was used to fund the acquisition of a 50% interest in BridgeTex). See Note 7 to our Consolidated Financial Statements for further discussion.

Our $150 million, 5.25% senior notes and $400 million, 3.95% senior notes matured in June 2015 and September 2015, respectively, and were repaid with borrowings under our commercial paper program.

In December 2013, our $250 million, 5.63% senior notes matured and were repaid with borrowings under our commercial paper program.

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

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

Acquisitions and Divestitures. The price of acquisitions includes cash paid, assumed liabilities and net working capital items. Because of the non-cash items included in the total price of the acquisition and the timing of certain cash payments, the net cash paid may differ significantly from the total price of the acquisitions completed during the year. During the years ended December 31, 2015, 2014 and 2013, we paid cash of $105 million, $1,098 million and $28 million, respectively, for acquisitions.

During the first quarter of 2016, we entered into binding agreements for the sale of various non-core assets for total consideration of approximately $325 million. We expect these transactions to close in the first half of 2016.

2016 Capital Projects. We expect the majority of funding for our 2016 capital program will be provided by the proceeds from our January 2016 preferred unit offering. Our capital program is highlighted by a large number of small-to-medium sized projects spread across multiple geographic regions/resource plays. We believe the diversity of our program mitigates the impact of delays, cost overruns or adverse market developments with respect to a particular project or geographic region/resource play. The majority of our 2016 expansion capital program will be invested in our fee-based Transportation and Facilities segments. We expect that our investments will have minimal contributions to our 2016 results, but will provide growth for 2017 and beyond. Our 2016 capital program includes the following projects as of February 2016 with the estimated cost for the entire year (in millions):

Projects	**2016**
Red River Pipeline (Cushing to Longview)	$290
Diamond Pipeline	260
Fort Saskatchewan Facility Projects	190
Permian Basin Area Pipeline Projects	185
Saddlehorn Pipeline	155
Cushing Terminal Expansions	35
St. James Terminal Expansions	35
Caddo Pipeline	30
Cactus Pipeline	20
Eagle Ford JV Project	20
Other Projects	280
	$1,500
Potential Adjustments for Timing / Scope Refinement (1)	-$100+ $100
Total Projected Expansion Capital Expenditures	$1,400 - $1,600
Maintenance Capital Expenditures	$190 - $210

(1) 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.

Distributions to our unitholders and general partner. We distribute 100% of our available cash within 45 days following the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. On February 12, 2016, we paid a quarterly distribution of $0.70 per common unit. This distribution represents a year-over-year distribution increase of approximately 3.7%. See Note 10 to our Consolidated Financial Statements for details of distributions paid. Also, see Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities Cash Distribution Policy for additional discussion regarding distributions.

Distributions to noncontrolling interests. We paid $3 million for distributions to noncontrolling interests during each of the years ended December 31, 2015 and 2014. These amounts represent distributions paid on interests in SLC Pipeline LLC that were not owned by us.

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

Contingencies

For a discussion of contingencies that may impact us, see Note 16 to our Consolidated Financial Statements.

Commitments

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

The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of December 31, 2015 (in millions):

	2016	2017	2018	2019	2020	2021 and Thereafter	Total
Long-term debt, including current maturities and related interest payments (1)	$ 1,324	$ 847	$ 1,019	$ 1,236	$ 834	$ 11,040	$ 16,300
Leases (2)	200	184	154	128	108	427	1,201
Other obligations (3)	680	364	145	149	146	581	2,065
Subtotal	2,204	1,395	1,318	1,513	1,088	12,048	19,566
Crude oil, natural gas, NGL and other purchases (4)	3,837	2,142	1,592	1,127	914	2,694	12,306
Total	$ 6,041	$ 3,537	$ 2,910	$ 2,640	$ 2,002	$ 14,742	$ 31,872

(1) Includes debt service payments, interest payments due on senior notes, the commitment fee on assumed available capacity under our credit facilities and long-term borrowings under our commercial paper program. Although there may be short-term borrowings under our credit facilities and commercial paper program, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no short-term borrowings were outstanding on the credit facilities or commercial paper program) in the amounts above. For additional information regarding our debt obligations, see Note 9 to our Consolidated Financial Statements.

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

Table of Contents

(3) Includes (i) other long-term liabilities (excluding approximately $33 million related to derivative activity included in Crude oil, natural gas, NGL and other purchases), (ii) storage, processing and transportation agreements and (iii) non-cancelable commitments related to our capital expansion projects, including projected contributions for our share of the capital spending of our equity method investments. The transportation agreements include approximately $930 million associated with an agreement to transport crude oil on a pipeline that is owned by an equity method investee, in which we own a 50% interest. Our commitment to transport is supported by crude oil buy/sell agreements with third parties (including Oxy) with commensurate quantities.

(4) Amounts are primarily based on estimated volumes and market prices based on average activity during December 2015. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil, NGL and natural gas. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the product is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. Additionally, we issue letters of credit to support insurance programs, derivative transactions and construction activities. At December 31, 2015 and 2014, we had outstanding letters of credit of approximately $46 million and $87 million, respectively.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements as defined by Item 303 of Regulation S-K.

Investments in Unconsolidated Entities

We have invested in entities that are not consolidated in our financial statements. Certain of these entities are borrowers under credit facilities. We are neither a co-borrower nor a guarantor under any such facilities. We may elect at any time to make additional capital contributions to any of these entities. The following table sets forth selected information regarding these entities as of December 31, 2015 (unaudited, dollars in millions):

Entity	Type of Operation	Our Ownership Interest	Total Entity Assets	Total Cash and Restricted Cash	Total Entity Debt

Settoon Towing, LLC	Barge Transportation Services	50%	$ 337	$	$ 226
BridgeTex Pipeline Company, LLC	Crude Oil Pipeline	50%	$ 857	$ 26	$
Caddo Pipeline LLC	Crude Oil Pipeline	50%	$ 54	$ 2	$
Diamond Pipeline LLC	Crude Oil Pipeline	50%	$ 178	$ 100	$
Eagle Ford Terminals Corpus Christi LLC	Crude Oil Terminal and Dock	50%	$ 62	$ 4	$
Eagle Ford Pipeline LLC	Crude Oil Pipeline	50%	$ 768	$ 14	$
Frontier Pipeline Company	Crude Oil Pipeline	50%	$ 26	$ 4	$
Saddlehorn Pipeline Company, LLC	Crude Oil Pipeline	40%	$ 365	$ 51	$
White Cliffs Pipeline, LLC	Crude Oil Pipeline	36%	$ 592	$ 24	$
Butte Pipe Line Company	Crude Oil Pipeline	22%	$ 28	$ 3	$

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