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- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;
- risks related to the development and operation of our facilities, including our ability to satisfy our contractual obligations to our customers at our facilities;
- factors affecting demand for natural gas and natural gas storage services and rates;
- general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns; and
- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the storage of natural gas and the processing, transportation, fractionation, storage and marketing of natural gas liquids.

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

## **PART I**

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

#### **General**

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

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

#### **Organizational History**

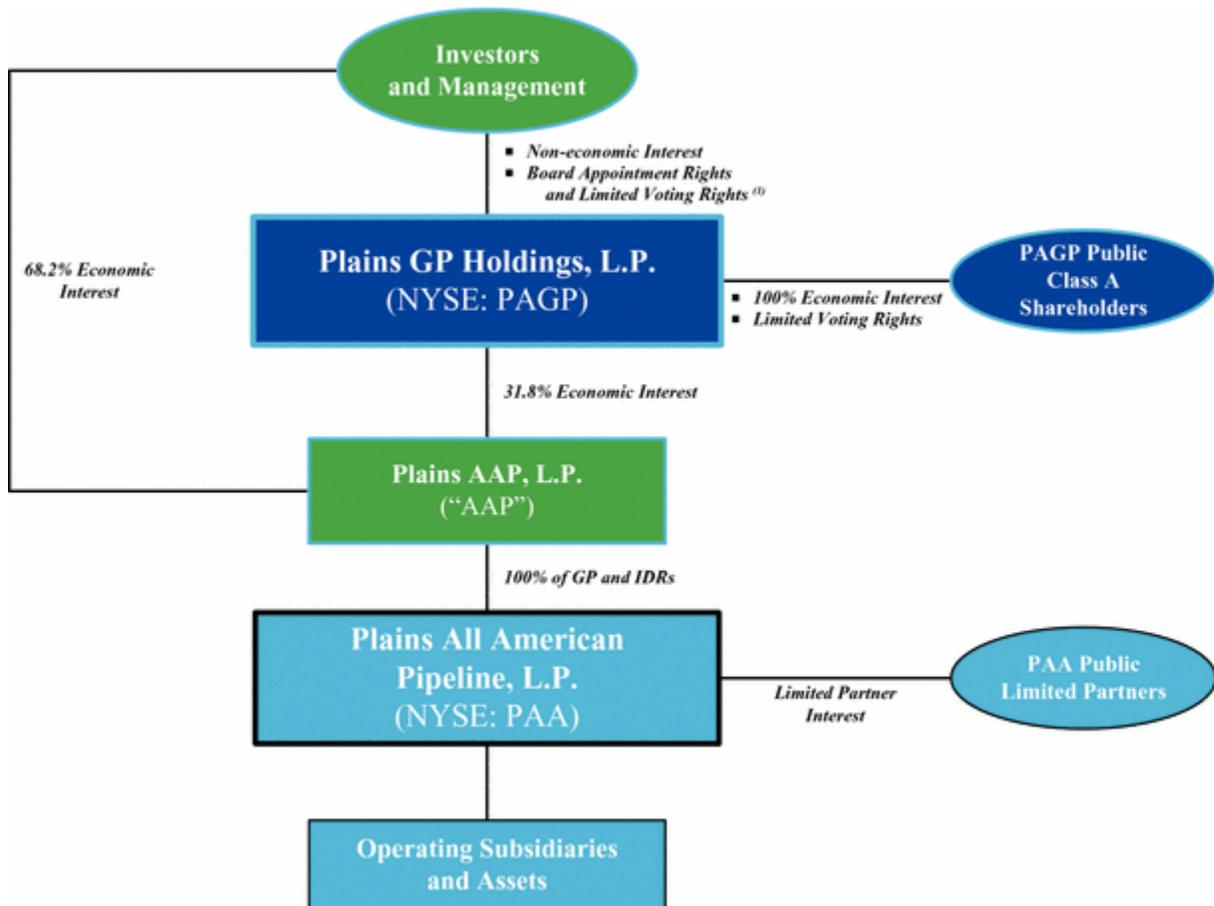
We were formed as a master limited partnership to acquire and operate the midstream crude oil businesses and assets of a predecessor entity and completed our initial public offering in 1998. Our 2% general partner interest is held by PAA GP LLC, a Delaware limited liability company, whose sole member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

**Partnership Structure and Management**

Our operations are conducted directly and indirectly through, and our operating assets are owned by, our subsidiaries. GP LLC has responsibility for conducting our business and managing our operations; however, PAGP effectively controls our business and affairs through the exercise of its rights as the sole and managing member of our general partner, including its right to appoint certain members to the board of directors of our general partner. See Item 10. “Directors and Executive Officers of our General Partner and Corporate Governance.” Our general partner does not receive a management fee or other compensation in connection with its management of our business, but it is reimbursed for substantially all direct and indirect expenses incurred on our behalf (other than expenses related to the Class B units of AAP which are referred to herein as the “AAP Management Units”).

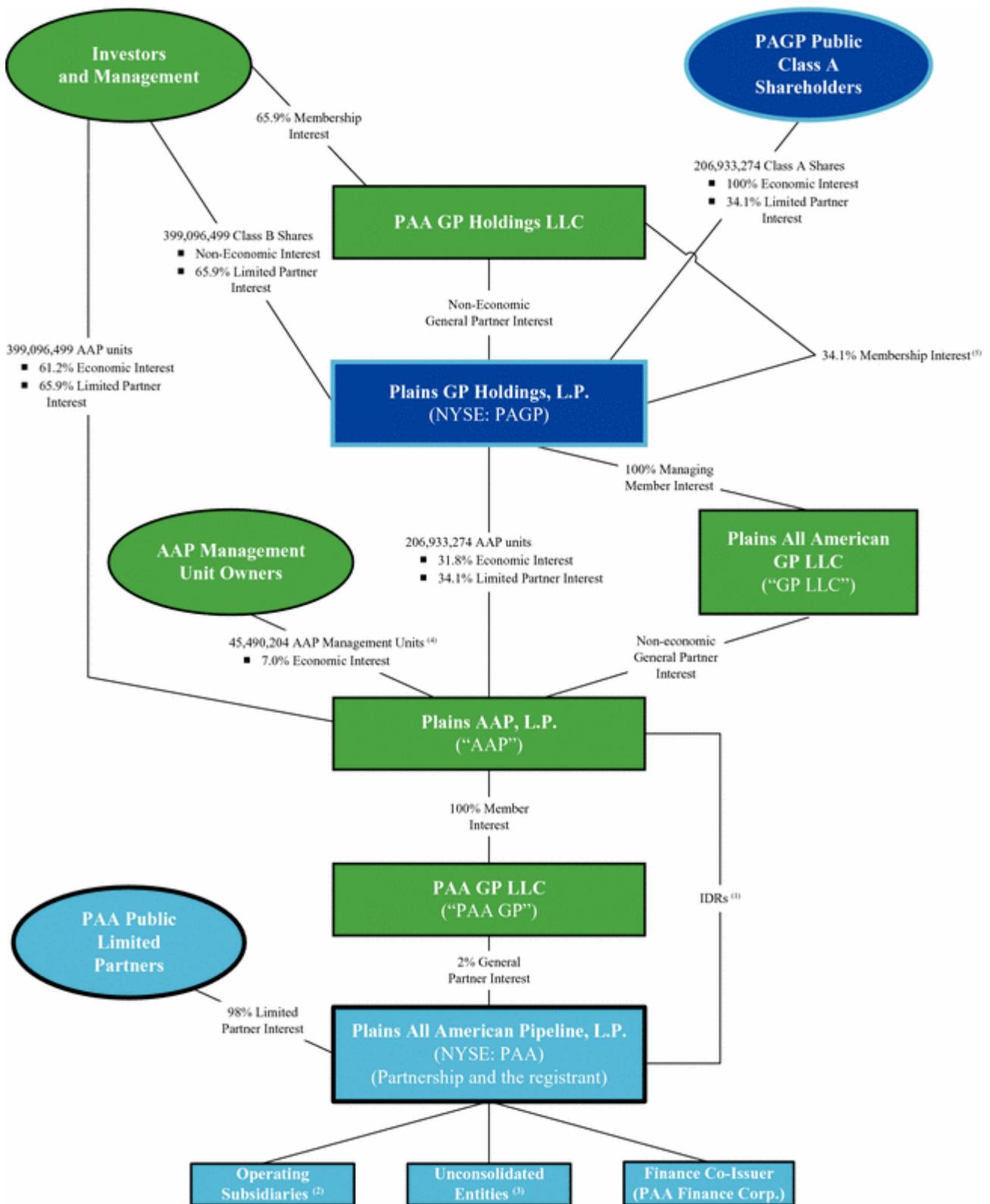
The two charts below show the structure and ownership of PAA and its subsidiaries as of December 31, 2014 in both a summarized and more detailed format. The first chart depicts PAA’s legal structure in summary format, while the second chart depicts a more comprehensive view of PAA’s legal structure,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

**Summarized Partnership Structure  
(as of December 31, 2014)**



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

Detailed Partnership Structure  
(as of December 31, 2014)



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- (1) See Item 5. “Market for Registrant’s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities” for discussion of our general partner’s IDRs.
  - (2) The Partnership holds direct and indirect ownership interests in consolidated operating subsidiaries including, but not limited to, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Midstream Canada ULC (“PMC”).
  - (3) The Partnership holds indirect equity interests in unconsolidated entities including Settoon Towing, LLC (“Settoon Towing”), White Cliffs Pipeline LLC (“White Cliffs”), Eagle Ford Pipeline LLC (“Eagle Ford Pipeline”), BridgeTex Pipeline Company, LLC (“BridgeTex”), Butte Pipe Line Company (“Butte”) and Frontier Pipeline Company (“Frontier”).
  - (4) Represents the number of Class A units of AAP (“AAP units”) for which the AAP Management Units would be exchangeable, assuming a conversion rate of approximately 0.925 AAP units for each AAP Management Unit as of December 31, 2014. The AAP Management Units are entitled to certain proportionate distributions paid by AAP.
  - (5) As of December 31, 2014, PAGP owned 34.1% of the membership interests in its general partner, which percentage corresponds to its ownership percentage of AAP units (34.1%, representing a 31.8% economic interest in AAP, including the dilutive effect of the AAP Management Units).

## **Business Strategy**

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

- commercially optimizing our existing assets and realizing cost efficiencies through operational improvements;
- using our transportation (including pipeline, rail, barge and truck), terminalling, storage, processing and fractionation assets in conjunction with our supply and logistics activities to capitalize on inefficient energy markets and to address physical market imbalances, mitigate inherent risks and increase margin;
- developing and implementing growth projects that (i) address evolving crude oil and NGL needs in the midstream transportation and infrastructure sector and (ii) are well positioned to benefit from long-term industry trends and opportunities; and
- selectively pursuing strategic and accretive acquisitions that complement our existing asset base and distribution capabilities.

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

## **Competitive Strengths**

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

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

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- *We possess specialized crude oil market knowledge.* We believe our business relationships with participants in various phases of the crude oil distribution chain, from crude oil producers to refiners, as well as our own industry expertise (including our knowledge of North American crude oil flows), provide us with an extensive understanding of the North American physical crude oil markets.
- *Our supply and logistics activities typically generate a base level of margin with the opportunity to realize incremental margins.* We believe the variety of activities executed within our supply and logistics segment in combination with our risk management strategies provides us with a balance that generally affords us the flexibility to maintain a base level of margin in a variety of market conditions (subject to the effects of seasonality). In certain circumstances, we are able to realize incremental margins during volatile market conditions.
- *We have the evaluation, integration and engineering skill sets and the financial flexibility to continue to pursue acquisition and expansion opportunities.* Since 1998, we have completed and integrated over 80 acquisitions with an aggregate purchase price of approximately \$11.6 billion. We have also implemented expansion capital projects totaling over \$7.8 billion. In addition, considering our investment grade credit rating, liquidity and capital structure, we believe we have the financial resources and strength necessary to finance future strategic expansion and acquisition opportunities. As of December 31, 2014, we had approximately \$2.6 billion of liquidity available, including cash and cash equivalents and availability under our committed credit facilities, subject to continued covenant compliance.
- *We have an experienced management team whose interests are aligned with those of our unitholders.* Our executive management team has an average of 30 years industry experience, and an average of 18 years with us or our predecessors and affiliates. In addition, through their ownership of common units, indirect interests in our general partner, grants of phantom units and AAP Management Units, our management team has a vested interest in our continued success.

## **Financial Strategy**

### ***Targeted Credit Profile***

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

- an average long-term debt-to-total capitalization ratio of approximately 50%;
- a long-term debt-to-adjusted EBITDA multiple averaging between 3.5x and 4.0x (Adjusted EBITDA is earnings before interest, taxes, depreciation and amortization, equity-indexed compensation plan charges, gains and losses from derivative activities and other selected items that impact comparability. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations — Non-GAAP Financial Measures” for a discussion of our selected items that impact comparability and our non-GAAP measures.);
- an average total debt-to-total capitalization ratio of approximately 60%; and
- an average adjusted EBITDA-to-interest coverage multiple of approximately 3.3x or better.

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

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

## Acquisitions

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

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

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

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

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

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

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

(5) Includes two transactions with Western.

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

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

## Ongoing Acquisition and Investment Activities

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

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

**Expansion Capital Projects**

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

<b>Basin/Region</b>	<b>Project</b>	<b>2015 Plan Amount <sup>(1)</sup> (\$ in millions)</b>	<b>Description</b>	<b>Projected In-Service Date</b>
Permian	Permian Basin Area Projects	\$ 365	Multiple projects to increase and expand our pipeline infrastructure in the Permian Basin, including expansion of trunklines into the Delaware Basin and corresponding looping of the Wink-to-Midland segment of our Basin Pipeline	Various, throughout 2015 and 2016
	Cactus Pipeline	85	310 miles of new crude oil pipeline; 250,000 Bbls/d capacity (to be expanded to 330,000 Bbls/d in 2016) from the Permian Basin to the Eagle Ford Pipeline	2015
Eagle Ford	Eagle Ford JV Project	85	55 miles of new gathering and trunkline pipeline to connect Karnes and Live Oak County production areas to the Three Rivers, TX terminal; 70 miles of new pipeline from Three Rivers to Corpus Christi, TX; expanded storage and pumping capacity at Three Rivers; Construction of new terminal on the Corpus Christi ship channel	Various, throughout 2015, 2016 and 2017
	Eagle Ford Area Projects	35	New condensate processing stabilizer with 40,000 Bbls/d of capacity; conversion of existing Gardendale, TX stabilizer into rich fuel gas use; installation of pumps, metering and 10 miles of pipeline enabling delivery of NGL out of our Gardendale processing plant	2015
Central / Mid-Continent	Diamond Pipeline	165	440 miles of new crude oil pipeline; 200,000 Bbls/d capacity from Cushing, OK to the Valero Memphis, TN refinery	2017
	Red River Pipeline	80	Approximately 400 miles of new crude oil pipeline; 150,000 Bbls/d capacity from Cushing, OK to Longview, TX	2016
	Cushing Terminal Expansions	25	Addition of 1.4 million barrels of storage capacity	2015
Rocky Mountain	Cowboy Pipeline	50	27 miles of new crude oil pipeline; 65,000 Bbls/d capacity from Cheyenne, WY to our rail loading facility near Carr, CO; construction of new terminal at Cheyenne	2015

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

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

**Global Petroleum Market Overview**

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

	Annual Liquids Production <sup>(1)</sup>				Projected		Δ from 2011 2014
	2011	2012	2013	2014	2015	2016	
(in millions of barrels per day)							
<b>Production (Supply)</b>							
U.S. & Canada	13.7	15.0	16.5	18.3	19.3	20.0	4.6
Rest of the World	74.2	74.8	73.7	73.8	73.7	73.5	(0.4)
Total <sup>(2)</sup>	<u>87.9</u>	<u>89.8</u>	<u>90.2</u>	<u>92.2</u>	<u>93.0</u>	<u>93.5</u>	<u>4.3</u>
(in millions of barrels per day)							
<b>Consumption (Demand)</b>							
U.S. & Canada	21.2	20.8	21.4	21.4	21.7	21.8	0.2
Rest of the World	67.3	68.3	69.1	70.0	70.7	71.6	2.7
Total <sup>(2)</sup>	<u>88.5</u>	<u>89.1</u>	<u>90.5</u>	<u>91.4</u>	<u>92.4</u>	<u>93.4</u>	<u>2.9</u>
U.S. & Canada Production as % of World Production <sup>(2)</sup>	16%	17%	18%	20%	21%	21%	4%
U.S. & Canada Consumption as % of World Consumption <sup>(2)</sup>	24%	23%	24%	23%	23%	23%	0%
Net U.S. & Canada (Consumption) <sup>(2)</sup>	<u>(7.4)</u>	<u>(5.8)</u>	<u>(4.8)</u>	<u>(3.1)</u>	<u>(2.4)</u>	<u>(1.8)</u>	<u>4.4</u>
Global Supply/Demand Balance	<u>(0.6)</u>	<u>0.6</u>	<u>(0.3)</u>	<u>0.8</u>	<u>0.6</u>	<u>0.1</u>	<u>1.3</u>

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

(2) Amounts may not recalculate due to rounding.

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

### ***Crude Oil Market Overview***

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

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

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

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

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

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

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

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

<sup>(1)</sup> Amounts may not recalculate due to rounding.

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

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

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

<sup>(1)</sup> Amounts may not recalculate due to rounding.

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

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

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

### ***Processed Condensate Market***

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

### ***Refined Products Market Overview***

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

The characteristics of the gasoline produced depend upon the setup of the refinery at which it is produced. Gasoline characteristics are also impacted by other ingredients that may be blended into it, such as ethanol and octane enhancers. The performance of the gasoline must meet strictly defined industry standards and environmental regulations that vary based on season and location.

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

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

## ***NGL Market Overview***

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

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

- *Ethane.* Ethane accounts for the largest portion of the NGL barrel and substantially all of the extracted ethane is used as feedstock in the production of ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. When ethane recovery from a wet natural gas stream is uneconomic, ethane is left in the natural gas stream, subject to pipeline specifications.
- *Propane.* Propane is used as heating fuel, engine fuel and industrial fuel, for agricultural burning and drying and also as petrochemical feedstock for the production of ethylene and propylene.
- *Normal butane.* Normal butane is principally used for motor gasoline blending and as fuel gas, either alone or in a mixture with propane, and feedstock for the manufacture of ethylene and butadiene, a key ingredient of synthetic rubber. Normal butane is also used as a feedstock for iso-butane production and as a diluent in the transportation of heavy crude oil and bitumen, particularly in Canada.
- *Iso-butane.* Iso-butane is principally used by refiners to produce alkylates to enhance the octane content of motor gasoline.
- *Natural Gasoline.* Natural gasoline is principally used as a motor gasoline blend stock, a petrochemical feedstock, or as diluent in the transportation of heavy crude oil and bitumen, particularly in Canada.

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

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

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

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

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

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

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

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

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

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

- the absolute prices of NGL products and their prices relative to natural gas and crude oil;
- drilling activity and wet natural gas production in developing liquids-rich production areas;
- production growth/decline rates of wet natural gas in established supply areas;
- available processing, fractionation, storage and transportation capacity;
- infrastructure development costs and timing as well as development risk sharing;
- the cost of acquiring rights from producers to process their gas;
- petro-chemical demand;
- diluent requirements for heavy Canadian oil;
- international demand for NGL products;
- regulatory changes in gasoline specifications affecting demand for butane;
- refinery shut downs;
- alternating needs of refineries to store and blend NGL;
- seasonal shifts in weather; and
- inefficiencies caused by regional supply and demand imbalances.

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

### ***Natural Gas Storage Market Overview***

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

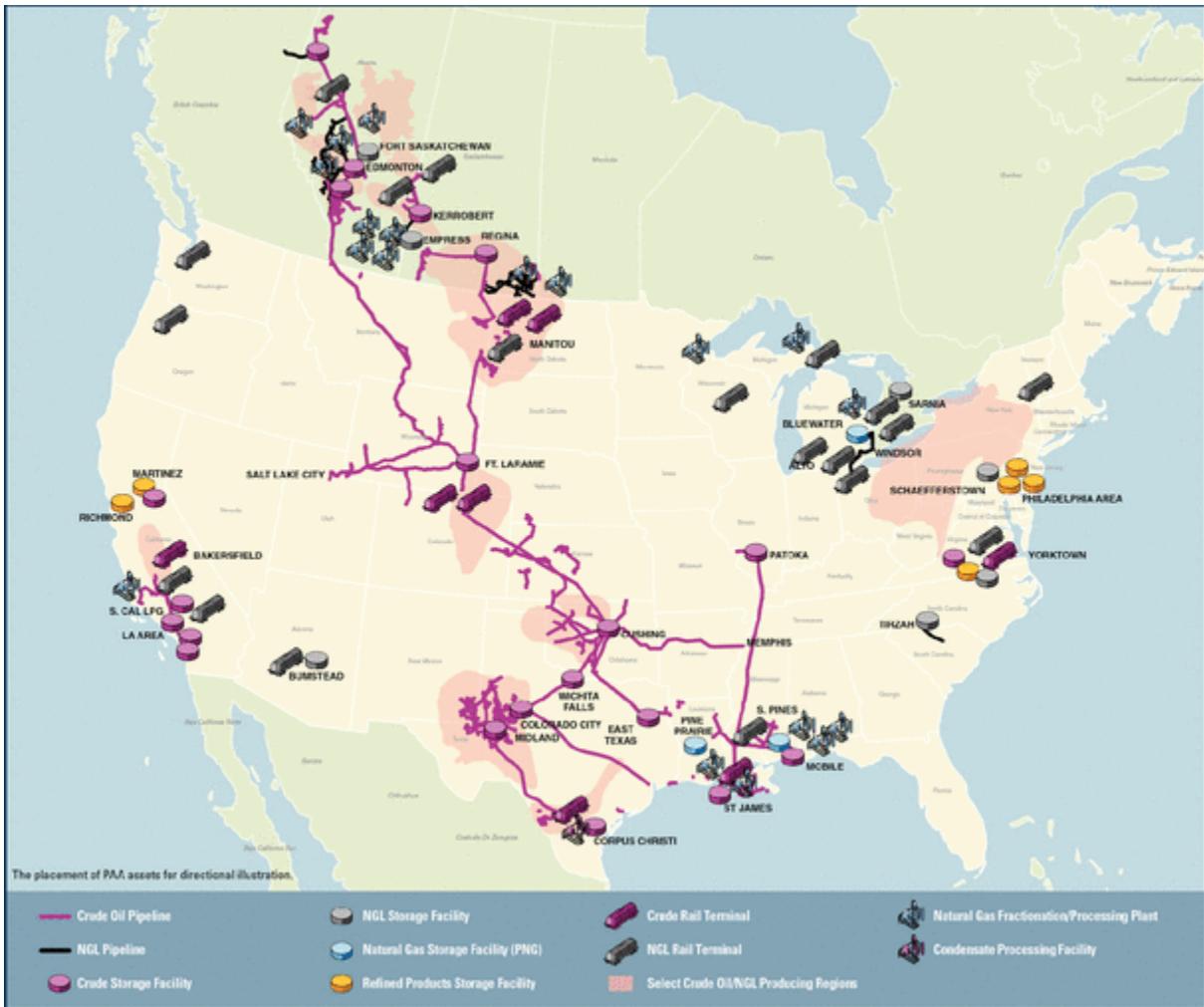
Overall market conditions for natural gas storage have been challenging during the last several years, driven by a variety of factors, including (i) increased natural gas supplies due to production from shale resources, (ii) a shift from Gulf of Mexico production to Northeast production causing less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

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

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

### **Description of Segments and Associated Assets**

Our business activities are conducted through three segments—Transportation, Facilities and Supply and Logistics. We have an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. The map below highlights our more significant assets (including certain assets under construction or development) as of December 31, 2014:



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

**Transportation Segment**

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

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

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

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

Region / Pipeline and Gathering Systems <sup>(1)</sup>	System Miles	2014 Average Net Barrels per Day <sup>(2)</sup> (in thousands)
<b>United States Crude Oil Pipelines</b>		
<b>Permian Basin</b>		
Basin / Mesa / Sunrise	682	733
BridgeTex <sup>(3)</sup>	408	14
Permian Basin Area Systems	2,838	765
<b>Permian Basin Subtotal</b>	<b>3,928</b>	<b>1,512</b>
<b>South Texas/Eagle Ford</b>		
Eagle Ford Area Systems	470	227
<b>Western</b>		
All American	138	37
Line 63 / Line 2000	342	122
Other	122	101
<b>Western Subtotal</b>	<b>602</b>	<b>260</b>
<b>Rocky Mountain</b>		
Bakken Area Systems	1,025	149
Salt Lake City Area Systems	969	136
White Cliffs <sup>(3)</sup>	1,054	30
Other	1,304	111
<b>Rocky Mountain Subtotal</b>	<b>4,352</b>	<b>426</b>
<b>Gulf Coast</b>		
Capline <sup>(3)</sup>	631	152
Other	915	340
<b>Gulf Coast Subtotal</b>	<b>1,546</b>	<b>492</b>
<b>Central</b>		
Mid-Continent Area Systems	2,345	348
Other	280	102
<b>Central Subtotal</b>	<b>2,625</b>	<b>450</b>
<b>United States Total</b>	<b>13,523</b>	<b>3,367</b>
<b>Canada</b>		
Crude Oil Pipelines:		
Manito	561	47
Rainbow	842	112
Rangeland	1,233	65
South Saskatchewan	346	62
Other	198	113
<b>Crude Oil Pipelines Subtotal</b>	<b>3,180</b>	<b>399</b>
NGL Pipelines:		
Co-Ed	632	58
Other	430	128
<b>NGL Pipelines Subtotal</b>	<b>1,062</b>	<b>186</b>
<b>Canada Total</b>	<b>4,242</b>	<b>585</b>
<b>Grand Total</b>	<b>17,765</b>	<b>3,952</b>

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- (1) Ownership percentage varies on each pipeline and gathering system ranging from approximately 20% to 100%.
  - (2) Represents average volume for the entire year attributable to our interest. Volumes associated with assets employed through acquisitions or expansion capital represent total volumes (attributable to our interest) for the number of days we employed the assets divided by the number of days in the year.
  - (3) Pipelines operated by a third party.

## **United States Pipelines**

### ***Permian Basin***

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

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

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

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

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

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

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

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

### ***South Texas/Eagle Ford Area***

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

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

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

### ***Western***

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

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

*Line 63.* We own and operate the Line 63 system. The Line 63 system is an intrastate common carrier crude oil pipeline system that transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. The Line 63 system consists of a 144-mile trunk pipeline, originating at our Kelley Pump Station in Kern County, California and terminating at our West Hynes Station in Long Beach, California. The trunk pipeline has a capacity of approximately 110,000 barrels per day. The Line 63 system includes five miles of distribution pipelines in the Los Angeles Basin, with a throughput capacity of approximately 144,000 barrels per day, and approximately 140 miles of gathering pipelines in the San Joaquin Valley, with an average throughput capacity of approximately 72,000 barrels per day. We also have approximately 1 million barrels of storage capacity on this system. These storage assets are used primarily to facilitate the transportation of crude oil on the Line 63 system. For 2014, combined throughput on Line 63 totaled an average of 48,000 barrels per day.

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During 2009, a 71-mile segment of Line 63 was temporarily taken out of service to allow for certain repairs and realignments to be performed. Line 63 volumes are currently being redirected from the north end of this out-of-service segment to the parallel Line 2000. The product is then batched along Line 2000 until it is re-injected into the active portion of Line 63, which is south of the out-of-service segment, for subsequent delivery to customers. This temporary pipeline segment closure and redirection of product has not impacted our normal throughput levels on this line. We have commenced a project to place this idle segment into service, which we expect to complete in 2015. In December 2014, we commenced receipts on Line 63 of crude oil from our rail terminal at Bakersfield.

*Line 2000.* We own and operate Line 2000, an intrastate common carrier crude oil pipeline that originates at our Emidio Pump Station (part of the All American Pipeline system) and transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin. Line 2000 is an approximately 130-mile, 20-inch trunk pipeline with a throughput capacity of approximately 130,000 barrels per day. During 2014, throughput on Line 2000 (excluding Line 63 volumes) averaged 74,000 barrels per day.

### ***Rocky Mountain***

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

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

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

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

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

### ***Gulf Coast***

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

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

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

## **Central**

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

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

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

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

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

## **Canada Pipelines**

### ***Crude Oil Pipelines***

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

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

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

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

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

### ***NGL Pipelines***

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

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

### ***Facilities Segment***

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

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

- approximately 73 million barrels of crude oil and refined products storage capacity primarily at our terminalling and storage locations;
- approximately 23 million barrels of NGL storage capacity;
- approximately 97 Bcf of natural gas storage working capacity;
- approximately 29 Bcf of owned base gas;
- 11 natural gas processing plants located throughout Canada and the Gulf Coast area of the United States;
- a condensate processing facility located in the Eagle Ford area of South Texas with an aggregate processing capacity of approximately 80,000 barrels per day;
- seven fractionation plants located throughout Canada and the United States with an aggregate gross processing capacity of approximately 221,800 barrels per day, and an isomerization and fractionation facility in California with an aggregate processing capacity of approximately 14,000 barrels per day;

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- 26 crude oil and NGL rail terminals located throughout the United States and Canada. See “-Major Facilities Assets - Rail Facilities” below for an overview of various terminals and “Supply and Logistics” regarding our use of railcars;
- six major marine facilities in the United States with an aggregate load capacity of 91,500 barrels per hour, including vapor recovery rates, and an aggregate unload capacity of 160,500 barrels per hour; and
- approximately 1,100 miles of active pipelines that support our facilities assets, consisting primarily of NGL and natural gas pipelines.

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

<b>Crude Oil and Refined Products Storage Facilities</b>		<b>Total Capacity (MMBbls)</b>			
<i>Cushing</i>				20	
<i>LA Basin</i>				8	
<i>Martinez and Richmond</i>				5	
<i>Mobile and Ten Mile</i>				2	
<i>Patoka</i>				6	
<i>Philadelphia Area</i>				4	
<i>St. James</i>				10	
<i>Yorktown <sup>(1)</sup></i>				5	
<i>Other</i>				13	
				<u>73</u>	
<b>NGL Storage Facilities</b>		<b>Total Capacity (MMBbls)</b>			
<i>Bumstead</i>				4	
<i>Fort Saskatchewan</i>				5	
<i>Sarnia Area</i>				8	
<i>Tirzah</i>				1	
<i>Other</i>				5	
				<u>23</u>	
<b>Natural Gas Storage Facilities</b>		<b>Total Capacity (Bcf)</b>			
<i>Salt-caverns and Depleted Reservoir</i>				97	
<b>Natural Gas Processing Facilities <sup>(2)</sup></b>		<b>Ownership Interest</b>	<b>Total Gas Inlet Volume <sup>(3)</sup> (Bcf/d)</b>	<b>Gross Gas Processing Capacity <sup>(4)</sup> (Bcf/d)</b>	<b>Net Gas Processing Capacity <sup>(4)</sup> (Bcf/d)</b>
<i>United States Gulf Coast Area</i>		100%	0.2	0.6	0.6
<i>Canada</i>		36-100%	1.3	6.7	5.4
			<u>1.5</u>	<u>7.3</u>	<u>6.0</u>
<b>Condensate Stabilization Facility</b>		<b>Total Capacity (Bbls/d)</b>			
<i>Gardendale</i>				80,000	
<b>NGL Fractionation and Isomerization Facilities</b>		<b>Ownership Interest</b>	<b>Total Inlet Volume <sup>(3)</sup> (Bbls/d)</b>	<b>Gross Capacity (Bbls/d)</b>	<b>Net Capacity (Bbls/d)</b>
<i>Fort Saskatchewan</i>		21-100%	23,622	75,000	51,300
<i>Sarnia</i>		62-84%	55,219	120,000	90,000
<i>Shafter</i>		100%	7,377	14,000	14,000
<i>Other</i>		82-100%	10,147	26,800	24,973
			<u>96,365</u>	<u>235,800</u>	<u>180,273</u>

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<b>Rail Facilities</b>	<b>Ownership Interest</b>	<b>Loading Capacity<sup>(5)</sup> (Bbls/d)</b>	<b>Unloading Capacity<sup>(5)</sup> (Bbls/d)</b>
<i>Crude Oil Rail Facilities</i>	100%	297,000	350,000
	<b>Ownership Interest</b>	<b>Number of Rack Spots</b>	<b>Number of Storage Spots</b>
<i>NGL Rail Facilities<sup>(4)</sup></i>	50-100%	249	1,139

- (1) Amount includes 1.1 million barrels of capacity for which we hold lease options (all of which have been exercised).
- (2) While natural gas processing inlet volumes and capacity amounts are presented, they currently are not a significant driver of our segment results.
- (3) Inlet volumes represent average inlet volumes net to our share for the entire year.
- (4) Capacity transported will vary according to specification of product moved.
- (5) Our NGL rail terminals are predominately utilized for internal purposes specifically for our supply and logistics activities. See our “-Supply and Logistics Segment” discussion following this section for further discussion regarding the use of our rail terminals.

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

### Major Facilities Assets

#### Crude Oil and Refined Products Facilities

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

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

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

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

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

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The Mobile Terminal is equipped with a ship/tanker dock, barge dock, truck unloading facilities and various third-party connections for crude oil movements to area refiners. Additionally, the Mobile Terminal serves as a source for imports of foreign crude oil to PADD II refiners through our Mississippi/Alabama pipeline system, which connects to the Capline System at our station in Liberty, Mississippi. Our Ten Mile Facility is connected to our Pascagoula pipeline, which was placed into service in early 2014.

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

*Philadelphia Area Terminals.* We own four refined product terminals in the Philadelphia, Pennsylvania area. Our Philadelphia area terminals have a combined storage capacity of 4 million barrels. The terminals have 20 truck loading lanes, two barge docks and a ship dock. The Philadelphia area terminals provide services and products to the refiners in the Philadelphia harbor. The Philadelphia area terminals also receive products from connecting pipelines.

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

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

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

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

### **NGL Storage Facilities**

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

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

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

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

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

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

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

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

### **Natural Gas Storage Facilities**

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

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

### **Natural Gas Processing Facilities**

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

### **Condensate Processing Facility**

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

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

### **NGL Fractionation and Isomerization Facilities**

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

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

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

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

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

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

### **Rail Facilities**

#### ***Crude Oil Rail Loading Facilities***

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

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

#### ***Crude Oil Rail Unloading Facilities***

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

#### ***NGL Rail Facilities***

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

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

### ***Supply and Logistics Segment***

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

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

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

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

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

- 13 million barrels of crude oil and NGL linefill in pipelines owned by us;
- 4 million barrels of crude oil and NGL linefill in pipelines owned by third parties and other long-term inventory;
- 990 trucks and 1,100 trailers; and
- 8,100 crude oil and NGL railcars (additionally, over 1,400 new crude oil railcars on order with delivery expected in 2015).

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

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

	<b>Volumes</b>
Crude oil lease gathering purchases	949
NGL sales	208
Supply and Logistics activities total	<u>1,157</u>

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

### ***Risk Management***

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

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

### **Geographic Data; Financial Information about Segments**

See Note 19 to our Consolidated Financial Statements.

### **Customers**

Marathon Petroleum Corporation and its subsidiaries accounted for approximately 17%, 15% and 16% of our revenues for the years ended December 31, 2014, 2013 and 2012, respectively. ExxonMobil Corporation and its subsidiaries accounted for approximately 15% for the year ended December 31, 2014 and approximately 13% of our revenues for each of the years ended December 31, 2013 and 2012. Phillips 66 and its subsidiaries accounted for approximately 11% of our revenues for the year ended December 31, 2013. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2014, 2013 and 2012. The majority of revenues from these customers pertain to our supply and logistics operations. The sales to these customers occur at multiple locations and we believe that the loss of these customers would have only a short-term impact on our operating results. There is risk, however, that we would not be able to identify and access a replacement market at

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

### **Competition**

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

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

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

### **Regulation**

Our assets, operations and business activities are subject to extensive legal requirements and regulations under the jurisdiction of numerous federal, state, provincial and local agencies. Many of these agencies are authorized by statute to issue, and have issued, requirements binding on the pipeline industry, related businesses and individual participants. The failure to comply with such legal requirements and regulations can result in substantial penalties. At any given time there may be proposals, provisional rulings or proceedings in legislation or under governmental agency or court review that could affect our business. The regulatory burden on our assets, operations and activities increases our cost of doing business and, consequently, affects our profitability, but we do not believe that these laws and regulations affect us in a significantly different manner than our competitors. We may at any time also be required to apply significant resources in responding to governmental requests for information and/or enforcement actions. In 2010 we settled by means of separate Consent Decrees, two Department of Justice (“DOJ”)/Environmental Protection Agency (“EPA”) proceedings regarding certain releases of crude oil. One Consent Decree applied to our crude oil pipelines in general and was terminated in November 2013. The remaining Consent Decree applies to a specific system. Although we believe that all material aspects of the injunctive elements of the remaining Consent Decree (costs and operational effects) have been incorporated into our budgeting and planning process, future proceedings could result in additional injunctive remedies, the effect of which would subject us to operational requirements and constraints that would not apply to our competitors.

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

### **Environmental, Health and Safety Regulation**

#### ***General***

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

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

***Pipeline Safety/Pipeline and Storage Tank Integrity Management***

A substantial portion of our petroleum pipelines and our storage tank facilities in the United States are subject to regulation by the Pipeline and Hazardous Materials Safety Administration (“PHMSA”) pursuant to the Hazardous Liquids Pipeline Safety Act of 1979, as amended (the “HLPESA”). The HLPESA imposes safety requirements on the design, installation, testing, construction, operation, replacement and management of pipeline and tank facilities. Federal regulations implementing the HLPESA 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 HLPESA was amended by the Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. These amendments have resulted in the adoption of rules by the Department of Transportation (“DOT”) that require transportation pipeline operators to implement integrity management programs, including more frequent inspections, correction of identified anomalies and other measures, to ensure pipeline safety in “high consequence areas” such as high population areas, areas unusually sensitive to environmental damage, and commercially navigable waterways. In the United States, our costs associated with the inspection, testing and correction of identified anomalies were approximately \$107 million in 2014, \$57 million in 2013 and \$39 million in 2012. Based on currently available information, our preliminary estimate for 2015 is that we will incur approximately \$75 million in capital expenditures and approximately \$27 million in operational expenditures associated with our required pipeline integrity management program. Significant additional expenses could be incurred if new or more stringently interpreted pipeline safety requirements are implemented. Currently, we believe our pipelines are in substantial compliance with HLPESA and the 2002 and 2006 amendments. In addition to required activities, our integrity management program includes several voluntary, multi-year initiatives designed to prevent incidents. Costs incurred for such activities were approximately \$21 million in 2014, \$22 million in 2013 and \$24 million in 2012, and our preliminary estimate for 2015 is that we will incur approximately \$31 million of such costs.

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

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

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

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

The DOT has adopted American Petroleum Institute Standard 653 (“API 653”) as the standard for the inspection, repair, alteration and reconstruction of steel aboveground petroleum storage tanks subject to DOT jurisdiction. API 653 requires regularly scheduled inspection and repair of tanks remaining in service. In the United States, costs associated with this program were approximately \$32 million, \$26 million and \$31 million in 2014, 2013 and 2012, respectively. For 2015, we have budgeted approximately \$34 million in connection with continued API 653 compliance activities and similar new EPA regulations for tanks not

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regulated by the DOT. Certain storage tanks may be taken out of service if we believe the cost of compliance will exceed the value of the storage tanks or replacement tankage may be constructed.

**Canada**

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

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

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

***Occupational Safety and Health***

**United States**

In the United States, we are subject to the requirements of the Occupational Safety and Health Act, as amended (“OSHA”) and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that certain information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. Certain of our facilities are subject to OSHA Process Safety Management (“PSM”) regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above specified thresholds or any process that involves 10,000 pounds or more of a flammable liquid or gas in one location. We believe that our operations are in substantial compliance with OSHA requirements, including general industry standards, recordkeeping requirements and monitoring of occupational exposure to regulated substances.

**Canada**

Similar regulatory requirements exist in Canada under the federal and provincial Occupational Health and Safety Acts, Regulations and Codes. The agencies with jurisdiction under these regulations are empowered to enforce them through inspection, audit, incident investigation or investigation of a public or employee complaint. In some jurisdictions, the agencies have been empowered to administer penalties for contraventions without the company first being prosecuted. Additionally, under the Criminal Code of Canada, organizations, corporations and individuals may be prosecuted criminally for violating the duty to protect employee and public safety. We believe that our operations are in substantial compliance with applicable occupational health and safety requirements.

### ***Solid Waste***

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

### ***Hazardous Substances***

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

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

### ***Environmental Remediation***

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

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

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

### ***Air Emissions***

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

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

***Climate Change Initiatives***

**United States**

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

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

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

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

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, demand for our services, financial condition, results of operations and cash flows, though our competitors would also be affected to a similar degree. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events that could have an adverse effect on our assets and operations.

**Canada**

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

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In 2007, in response to the Kyoto Protocol, the Canadian federal government introduced the *Regulatory Framework for Air Emissions* (also known as the “Turning the Corner” measures), a regulatory framework for monitoring industrial GHG emissions by establishing mandatory emissions reduction requirements on a sector basis. Since 2004, companies emitting more than 100 thousand tons per year (“kt/y”) of CO<sub>2</sub> equivalent (“CO<sub>2</sub>e”) were required to report their GHG emissions under the Greenhouse Gas Emissions Reporting Program. In 2010, this reporting threshold was reduced to 50 kt/y. Two PMC facilities meet this reporting threshold. Originally, the framework was intended to be implemented by 2010; however no federally mandated reduction targets for GHGs have been implemented to date. Canada has taken sectoral action on two of its largest sources of emissions — electricity and vehicles. Construction of traditional coal fired generation has been banned and new vehicle emissions and fuel efficiency standards have been established through to 2025.

In Alberta, the provincial government implemented the Specified Gas Emitter Regulation in 2007 (under the Alberta Environment Protection and Enhancement Act), which mandated a 12% reduction in emission intensity over the established baseline level (average of the 2003-2005 levels) for all facilities emitting more than 100kt/y of CO<sub>2</sub>e. Since the regulation came into effect, PMC has one facility (Fort Saskatchewan Storage and Fractionation Facility) which currently does not meet the reduction obligation. As such, PMC has been required to submit compliance credits which have been completed by submitting payment to the Climate Change Emissions Management Fund. Alberta also has a GHG reporting threshold at 50kt/y of CO<sub>2</sub>e.

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

### **Water**

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act (“CWA”), and analogous state and Canadian federal and provincial laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters of the United States and Canada, as well as state and provincial waters. See “—Pipeline Safety/Pipeline and Storage Tank Integrity Management” above and Note 17 to our Consolidated Financial Statements. Federal, state and provincial regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with discharge permits or other requirements of the CWA.

The Oil Pollution Act of 1990 (“OPA”) amended certain provisions of the CWA, as they relate to the release of petroleum products into navigable waters. OPA subjects owners of facilities to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages and certain other consequences of an oil spill. We believe that we are in substantial compliance with applicable OPA requirements. State and Canadian federal and provincial laws also impose requirements relating to the prevention of oil releases and the remediation of areas affected by releases when they occur. We believe that we are in substantial compliance with all such federal, state and Canadian requirements.

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

### **Endangered Species**

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

## Other Regulation

### *Transportation Regulation*

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

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

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

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

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

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

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

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

## ***Trucking Regulation***

### **United States**

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

### **Canada**

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

## ***Railcar Regulation***

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

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

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

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

### ***Cross Border Regulation***

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

### ***Market Anti-Manipulation Regulation***

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

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

### ***Natural Gas Storage Regulation***

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

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

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

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

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Under the Energy Policy Act of 2005 (“EPAAct 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. EPAAct 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 EPAAct 2005.

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

### **Operational Hazards and Insurance**

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

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

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

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

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

## **Employees and Labor Relations**

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

## **Summary of Tax Considerations**

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

### ***Partnership Status; Cash Distributions***

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

### ***Partnership Allocations***

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

### ***Basis of Common Units***

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

### ***Limitations on Deductibility of Partnership Losses***

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

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

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

### ***Section 754 Election***

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

### ***Disposition of Common Units***

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

### ***State, Local and Other Tax Considerations***

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

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

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

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

## Available Information

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

## Item 1A. Risk Factors

### Risks Related to Our Business

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

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

- As these projects are undertaken, required approvals, permits and licenses may not be obtained, may be delayed or may be obtained with conditions that materially alter the expected return associated with the underlying projects;
- We may face opposition to our planned growth projects from environmental groups, landowners, local groups and other advocates, including lawsuits or other actions designed to disrupt or delay our planned projects;
- We may not be able to secure, or we may be significantly delayed in obtaining, all of the rights of way or other real property interests we need to complete such projects, or the costs we incur in order to obtain such rights of way or other interests may be greater than we anticipated;
- Despite the fact that we will expend significant amounts of capital during the construction phase of these projects, revenues associated with these organic growth projects will not materialize until the projects have been completed and placed into commercial service, and the amount of revenue generated from these projects could be significantly lower than anticipated for a variety of reasons;
- We may construct pipelines, facilities or other assets in anticipation of market demand that dissipates or market growth that never materializes;
- Due to unavailability or costs of materials, supplies, power, labor or equipment, the cost of completing these projects could turn out to be significantly higher than we budgeted and the time it takes to complete construction of these projects and place them into commercial service could be significantly longer than planned; and
- The completion or success of our projects may depend on the completion or success of third-party facilities over which we have no control.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

***Acquisitions involve risks that may adversely affect our business.***

Any acquisition involves potential risks, including:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons, including crude oil, NGL and refined products, as well as our operations involving the storage of natural gas, are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment. Our operations are also subject to laws and regulations relating to protection of the environment and wildlife, operational safety, climate change and related matters. Compliance with all of these laws and regulations increases our overall cost of doing business, including our capital costs to construct, maintain and upgrade equipment and facilities. For example, the adoption of legislation or regulatory programs to reduce emissions of

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greenhouse gases, including cap and trade programs, could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. In addition, with respect to our railcar operations, the adoption of new regulations designed to enhance the overall safety of crude oil and natural gas liquids transportation by rail, including new regulations requiring that existing railcars be retrofitted or upgraded to improve integrity, could result in increased operating costs and potentially involve substantial capital expenditures. Also, the failure to comply with any such laws and regulations could result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, the issuance of injunctions that may subject us to additional operational requirements and constraints, or claims of damages to property or persons resulting from our operations. The laws and regulations applicable to our operations are subject to change and interpretation by the relevant governmental agency, including the possibility that exemptions we currently qualify for may be modified or changed in ways that require us to incur significant additional compliance costs. Any such change or interpretation adverse to us could have a material adverse effect on our operations, revenues, expenses and profitability.

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

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

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

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

Demand for crude oil and other hydrocarbon products we handle is dependent upon a variety of factors, including price, the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation, including climate change regulations, and technological advances in fuel economy and energy generation devices. For example, the adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could increase the cost of consuming crude oil and other hydrocarbon products, thereby causing a reduction in the demand for such products. Demand also depends on the ability and willingness of shippers having access to our transportation assets to satisfy their demand by deliveries through those assets.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

- a significant portion of our cash flow will be dedicated to the payment of principal and interest on our indebtedness and may not be available for other purposes, including the payment of distributions on our units and capital expenditures;
- credit rating agencies may view our debt level negatively;
- covenants contained in our existing debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business;
- our ability to obtain additional financing for working capital, capital expenditures, acquisitions and general partnership purposes may be limited;
- we may be at a competitive disadvantage relative to similar companies that have less debt; and
- we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

#### **Risks Inherent in an Investment in Us**

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

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

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

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

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***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 66<sup>2</sup>/<sub>3</sub>% of our outstanding units (including units held by our general partner or its affiliates). Because the owners of our general partner, along with directors and executive officers and their affiliates, own a significant percentage of our outstanding common units, the removal of our general partner would be difficult without the consent of both our general partner and its affiliates.

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

- generally, if a person acquires 20% or more of any class of units then outstanding other than from our general partner or its affiliates, the units owned by such person cannot be voted on any matter; and
- limitations upon the ability of unitholders to call meetings or to acquire information about our operations, as well as other limitations upon the unitholders' ability to influence the manner or direction of management.

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

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

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

- an existing unitholder's proportionate ownership interest in the Partnership will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

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

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

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

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

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

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

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

These conflicts may include the following:

- under our partnership agreement, we reimburse the general partner for the costs of managing and for operating the partnership;
- the amount of cash expenditures, borrowings and reserves in any quarter may affect available cash to pay quarterly distributions to unitholders;
- the general partner tries to avoid being liable for partnership obligations. The general partner is permitted to protect its assets in this manner by our partnership agreement. Under our partnership agreement the general partner would not breach its fiduciary duty by avoiding liability for partnership obligations even if we can obtain more favorable terms without limiting the general partner's liability; under our partnership agreement, the general partner may pay its affiliates for any services rendered on terms fair and reasonable to us. The general partner may also enter into additional contracts with any of its affiliates on behalf of us. Agreements or contracts between us and our general partner (and its affiliates) are not necessarily the result of arms length negotiations; and
- the general partner would not breach our partnership agreement by exercising its call rights to purchase limited partnership interests or by assigning its call rights to one of its affiliates or to us.

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

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

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

### **Risks Related to an Investment in Our Debt Securities**

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

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

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

Our leverage is significant in relation to our partners' capital. At December 31, 2014, our total outstanding long-term debt was approximately \$8.8 billion, and our total outstanding short-term debt (including current maturities of senior notes) was approximately \$1.3 billion. We will be prohibited from making cash distributions during an event of default under any of our indebtedness. Various limitations in our credit facilities and other debt instruments may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

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

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

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

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

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

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

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

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

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- to provide for the proper conduct of our business and the businesses of our operating partnerships (including reserves for future capital expenditures and for our anticipated future credit needs);
- to provide funds for distributions to our unitholders and the general partner for any one or more of the next four calendar quarters; or
- to comply with applicable law or any of our loan or other agreements.

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

### **Tax Risks to Common Unitholders**

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

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

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

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

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

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

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

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***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

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payment obligations in additional jurisdictions. Tax-exempt entities and non-U.S. persons should consult their tax advisor before investing in our common units.

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

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

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

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

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

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

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

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

Because there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units may be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

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

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

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

None.

### **Item 3. Legal Proceedings**

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

### **Environmental**

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

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

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

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

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

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

### ***Insurance***

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

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

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

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

Not applicable.