

PLAINS ALL AMERICAN PIPELINE LP  
Form 10-K  
February 25, 2011  
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**UNITED STATES**  
**SECURITIES AND EXCHANGE COMMISSION**

Washington, D.C. 20549

**Form 10-K**

(Mark One)

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

For the fiscal year ended December 31, 2010

or

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

Commission file number 1-14569

**PLAINS ALL AMERICAN PIPELINE, L.P.**

(Exact name of registrant as specified in its charter)

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**Delaware**

(State or other jurisdiction of incorporation or organization)

**333 Clay Street, Suite 1600, Houston, Texas**

(Address of principal executive offices)

**76-0582150**

(I.R.S. Employer Identification No.)

**77002**

(Zip Code)

**(713) 646-4100**

(Registrant's telephone number, including area code)

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

<b>Title of Each Class</b>	<b>Name of Each Exchange on Which Registered</b>
Common Units	New York Stock Exchange

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

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

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

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

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

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

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

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Large Accelerated Filer

Accelerated Filer

Non-Accelerated Filer   
(Do not check if a smaller  
reporting company)

Smaller Reporting Company

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

The aggregate market value of the Common Units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Common Units outstanding, for this purpose, as if they may be affiliates of the registrant) was approximately \$7.0 billion on June 30, 2010, based on \$58.70 per unit, the closing price of the Common Units as reported on the New York Stock Exchange on such date.

As of February 22, 2011, there were 141,199,175 Common Units outstanding.

**DOCUMENTS INCORPORATED BY REFERENCE**

**NONE**

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**PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES**

**FORM 10-K 2010 ANNUAL REPORT**

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**FORWARD-LOOKING STATEMENTS**

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

- failure to implement or capitalize on planned internal growth projects;
  
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
  
- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;
  
- the effectiveness of our risk management activities;
  
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
  
- abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline systems;
  
- shortages or cost increases of supplies, materials or labor;
  
- the availability of adequate third-party production volumes for transportation and marketing in the areas in which we operate and other factors that could cause declines in volumes shipped on our pipelines by us and third-party shippers, such as declines in production from existing oil and gas reserves or failure to develop additional oil and gas reserves;

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- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transportation throughput requirements;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;
- the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;
- unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);
- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements, and related interpretations;
- the effects of competition;
- interruptions in service on third-party pipelines;
- increased costs or lack of availability of insurance;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;

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- the currency exchange rate of the Canadian dollar;
- weather interference with business operations or project construction;
- risks related to the development and operation of natural gas storage facilities;
- future developments and circumstances at the time distributions are declared;
- 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, refined products and liquefied petroleum gas and other natural gas related petroleum products.

Other factors described herein, or 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.

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We engage in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products. We refer to liquefied petroleum gas and other natural gas-related petroleum products collectively as LPG. Through our general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P. (NYSE: PNG), we also engage in the acquisition, development and operation of natural gas storage facilities. Our business activities are conducted through three 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. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P.'s general partner. References to our general partner, as the context requires, include any or all of PAA GP LLC, Plains AAP, L.P. and Plains All American GP LLC. Plains AAP, L.P. and Plains All American GP LLC are owned by 18 holders and their affiliates. The five largest of these holders and their affiliates own an aggregate interest of approximately 95%. See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters Beneficial Ownership of General Partner Interest.

### **Partnership Structure and Management**

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. Plains All American GP LLC has ultimate responsibility for conducting our business and managing our operations. 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 Plains AAP, L.P.).



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The chart below depicts the current structure and ownership of Plains All American Pipeline, L.P. and certain subsidiaries as of February 22, 2011.

**Partnership Structure**

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(1) Based on Form 4 filings for executive officers and directors, 13D filings for Richard Kayne and other information believed to be reliable for the remaining investors, this group, or affiliates of such investors, owns approximately 9 million limited partner units, representing approximately 7% of all outstanding units.

(2) Incentive Distribution Rights ( IDRs ). 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 incentive distribution rights.

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

(4) The Partnership holds direct and indirect equity interests in unconsolidated entities including Settoon Towing, LLC ( Settoon Towing ), Butte Pipe Line Company ( Butte ), Frontier Pipeline Company ( Frontier ) and White Cliffs Pipeline, LLC ( White Cliffs ).

### **Business Strategy**

Our principal business strategy is to provide competitive and efficient midstream transportation, terminalling, storage and supply and logistics services to our producer, refiner and other customers. Toward this end, we endeavor to address regional supply and demand imbalances for crude oil, refined products, LPG and natural gas storage in the United States and Canada by combining the strategic location and capabilities of our transportation, terminalling and storage assets with our extensive supply, logistics and distribution expertise.

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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:

- optimizing our existing assets and realizing cost efficiencies through operational improvements;
- developing and implementing internal growth projects that (i) address evolving crude oil, refined products and LPG needs in the midstream transportation and infrastructure sector and (ii) are well positioned to benefit from long-term industry trends and opportunities;
- utilizing our assets along the Gulf, West and East Coasts along with our terminals and leased assets to optimize our presence in the waterborne importation of foreign crude oil;
- capitalizing on the anticipated long-term growth in demand for natural gas storage services in North America by owning and operating high-quality natural gas storage facilities and providing our current and future customers reliable, competitive and flexible natural gas storage and related services;
- selectively pursuing strategic and accretive acquisitions that complement our existing asset base and distribution capabilities; and
- using our terminalling and storage 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.

We intend to utilize PNG as the primary vehicle through which we will participate in the natural gas storage business. We believe PNG's natural gas storage assets are also well-positioned to benefit from long-term industry trends and opportunities. PNG's growth strategies are to develop and implement internal growth projects and to selectively pursue strategic and accretive acquisitions of natural gas storage projects and facilities. Through execution of such growth strategies, we intend to expand the scale and scope of our natural gas storage business. We may also prudently and economically leverage our asset base, knowledge base and skill sets to participate in other energy-related businesses that have characteristics and opportunities similar to, or that otherwise complement, our existing activities.

**Financial Strategy**

*Targeted Credit Profile*

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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 our investment grade credit rating. We have targeted a general credit profile with the following attributes:

- an average long-term debt-to-total capitalization ratio of approximately 50%;
- an adjusted 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 compensation plan charges, gains and losses from derivative activities and 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. In certain market conditions, we also incur short-term debt in connection with supply and logistics activities that involve the simultaneous purchase and forward sale of crude oil, refined products, LPG and natural gas. The crude oil, refined products, LPG and natural gas purchased in these transactions are hedged. We do not consider the working capital borrowings associated with this activity to be part of our long-term capital structure. These borrowings

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are self-liquidating as they are repaid with sales proceeds. We also incur short-term debt for New York Mercantile Exchange ( NYMEX ) and IntercontinentalExchange ( ICE ) margin requirements.

In order for us to maintain our targeted credit profile and achieve growth through internal growth projects and acquisitions, we intend to fund 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 capital expansion projects to adjusted EBITDA.

## **Competitive Strengths**

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

- *Many of our transportation segment and facilities segment 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 oil producing regions and transportation corridors, and are connected, directly or indirectly, with our facilities segment assets 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.
- *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, provide us with an extensive understanding of the North American physical crude oil markets.
- *Our crude oil supply and logistics activities are balanced.* We believe the variety of activities executed within our supply and logistics segment provides us with a balance that generally affords us the flexibility to maintain a base level of margin in a variety of crude oil market conditions and in certain circumstances, to realize incremental margin 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.* Over the past thirteen years, we have completed and integrated approximately 65 acquisitions with an aggregate purchase price of approximately \$6.8 billion. We have also implemented internal expansion capital projects totaling approximately \$2.5 billion. In addition, we believe we have resources to finance future strategic expansion and acquisition opportunities. As of December 31, 2010, we had a working capital surplus of approximately \$166 million and approximately \$841 million available 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 26 years industry experience, and an average of 15 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 the Class B units in Plains AAP, L.P., our

management team has a vested interest in our continued success.

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The acquisition of assets and businesses that are strategic and complementary to our existing operations constitutes an integral component of our business strategy and growth objective. Such assets and businesses include crude oil related assets, refined products assets, LPG assets and natural gas storage assets, as well as other energy transportation related assets that have characteristics and opportunities similar to these business lines and enable us to leverage our asset base, knowledge base 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	Date	Description	Approximate Purchase Price
SG Resources Mississippi, LLC ( SG Resources )	Feb-2011	Southern Pines Energy Center ( Southern Pines ) natural gas storage facility	\$ 746(1)
Nexen Holdings U.S.A. Inc. ( Nexen )	Dec-2010	Crude oil gathering and transportation assets in North Dakota and Montana	\$ 229
PAA Natural Gas Storage, LLC	Sep-2009	Remaining 50% interest in PNGS	\$ 215(2)
Rainbow Pipe Line Company, Ltd	May-2008	Crude oil gathering and transportation assets in Alberta, Canada	\$ 687
Pacific Energy Partners LP ( Pacific )	Nov-2006	Merger of Pacific Energy Partners with and into the Partnership	\$ 2,456
Andrews Petroleum and Lone Star Trucking ( Andrews )	Apr-2006	Isomerization, fractionation, marketing and transportation services	\$ 220

(1) Acquisition made by our subsidiary PNG.

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

*Southern Pines Acquisition.* On February 9, 2011, PNG acquired 100% of the equity interests in SG Resources (the Southern Pines Acquisition ), which entity owns the Southern Pines Energy Center natural gas storage facility, for total consideration of approximately \$746 million, subject to certain post-closing adjustments.

Southern Pines is a Federal Energy Regulatory Commission ( FERC )-regulated, high-performance, salt-cavern natural gas storage facility located in Greene County, Mississippi. The facility s current permits allow for 40 billion cubic feet ( Bcf ) of working capacity from four storage caverns. The facility commenced service in 2008 and three caverns have been placed into service, which are serving over 17 Bcf of customer contracts. These caverns are being expanded over time to their permitted capacity of 10 Bcf each. The fourth cavern is currently being drilled and is

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anticipated to be placed into service in the third quarter of 2012. The facility has the capacity for further expansion beyond 40 Bcf, if warranted by market demand and subject to receipt of required additional permits. Southern Pines is connected directly or indirectly to eight major natural gas pipelines servicing the Gulf Coast, Northeast, Mid-Atlantic and Southeastern U.S. markets.

See *Recent Developments* for discussion of transactions completed in conjunction with this acquisition.



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***Ongoing Acquisition Activities***

Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase of 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, other energy related assets that have characteristics and opportunities similar to our business lines and enable us to leverage our asset base, knowledge base and skill sets. Such acquisition efforts may involve participation by us in processes that have been made public and involve a number of potential buyers, commonly referred to as auction processes, as well as situations in which we believe we are the only party or one of a limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets which, if acquired, could have a material effect on our financial condition and results of operations. Even after we have reached agreement on a purchase price with a potential seller, confirmatory due diligence or negotiations regarding other terms of the acquisition can cause discussions to be terminated. Accordingly, we typically do not announce a transaction until after we have executed a definitive acquisition agreement. Although we expect the acquisitions 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 *Our acquisition strategy involves risks that may adversely affect our business.*

***Recent Developments***

During early 2011, we completed several noteworthy business transactions such as the completion of the Southern Pines acquisition for total consideration of approximately \$746 million, subject to certain post-closing adjustments, as discussed within the preceding *Acquisitions* section. In conjunction with this acquisition, PNG completed a private placement of 17.4 million common units to third-party purchasers for net proceeds of approximately \$370 million. In addition, we purchased approximately 10.2 million PNG common units for approximately \$230 million including our proportionate general partner contribution of \$12 million. As a result of these transactions, our aggregate ownership interest in PNG decreased from approximately 77% to approximately 64%.

In addition, during early 2011, we also expanded our liquidity through various transactions such as completion of a \$600 million senior notes offering and by entering into a \$500 million 364-day senior unsecured credit facility. In addition, we redeemed our 7.75% senior notes that were maturing in 2012 for approximately \$222 million.

**Global Petroleum Market Overview**

The United States comprises less than 5% of the world's population, generates 11% of the world's petroleum production, and consumes 22% of the world's petroleum production. The following table sets forth projected world supply and demand for petroleum products (including crude oil, natural gas liquids ( NGL ) and other liquid petroleum products) and is derived from the Energy Information Administration's ( EIA ) Annual Energy Outlook 2011 Early Release (see EIA website at [www.eia.doe.gov](http://www.eia.doe.gov)).

2010 (1)	2011	Projected 2012	2015
	(In millions of barrels per day)		

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Supply

OECD (2)				
U.S.	9.6	9.6	9.8	10.3
Other	11.6	11.3	11.1	10.5
Total OECD	21.2	20.9	20.9	20.8
Organization of the Petroleum Exporting Countries	34.8	35.6	36.5	37.2
Other	30.4	30.9	31.5	32.4
Total World Production	86.4	87.4	88.9	90.4

	2010 (1)	2011	Projected 2012	2015
	(In millions of barrels per day)			
<u>Demand</u>				
OECD				
U.S.	19.1	19.1	20.0	20.5
Other	26.6	26.6	26.5	26.0
Total OECD	45.7	45.7	46.5	46.5
Other	40.7	41.7	42.4	43.9
Total World Consumption	86.4	87.4	88.9	90.4
U.S. Production as % of World Production	11%	11%	11%	11%
U.S. Consumption as % of World Consumption	22%	22%	22%	23%
Net U.S. Consumption	(9.5)	(9.5)	(10.2)	(10.2)

(1) The 2010 amounts are based on ten months of actual data and two months of data derived from a short-term energy model published by the EIA.

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

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

**Crude Oil Market Overview**

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

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

Our assets and our business strategy are designed to serve our producer and refiner customers by addressing regional crude oil supply and demand imbalances that exist in the United States and Canada. For the 20-year time period beginning in 1985 through 2004, U.S. refinery demand for crude oil increased 29% from 12.0 million barrels per day to approximately 15.5 million barrels per day. U.S. refinery demand for crude oil demand remained effectively flat from 2005 through 2007 at around 15.5 million barrels per day, after which refinery demand decreased to average approximately 14.6 million barrels per day for the 12 months ended October 2010. Of this amount, only 5.5 million barrels per day was produced domestically. Accordingly, approximately 62% of the crude oil used by U.S. domestic refineries is imported. This imbalance represents a multi-year trend, with foreign imports of crude oil tripling over a 23-year period, from 3.2 million barrels per day in 1985 to approximately 10.1 million barrels per day from 2005-2007. Concurrent with decreased refinery demand and recent increases in domestic production, foreign crude imports have slowed to 9.1 million barrels per day for the 12 months ended October 2010. Reduced demand for petroleum products from end users as well as increased use of ethanol for blending in gasoline have been major factors contributing to the drop in refinery demand for crude oil. Since 2000, ethanol production has grown from approximately 100,000 barrels per day to approximately 840,000 barrels per day for the 12 months ended October 2010. Growth in ethanol and other renewable fuel production is expected to continue. The EIA is currently forecasting a continued gradual decline in foreign crude imports from current levels, which is attributable to increased domestic production, increased refined product imports and increase supply from other liquid products, including ethanol and biodiesel. The table below shows the overall domestic petroleum consumption projected out to 2015 and is derived from recent information published by the EIA (see EIA website at [www.eia.doe.gov](http://www.eia.doe.gov)). The amounts in the 2010 column are based on the twelve months from November 2009 to October 2010.

	Actual 2010	2011 (In millions of barrels per day)	Projected 2012	2015
Supply				
Domestic Crude Oil Production	5.5	5.3	5.4	5.7
Net Imports - Crude Oil	9.1	9.2	9.0	8.8

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Crude Oil Input to Domestic Refineries	14.6	14.5	14.4	14.5
Net Product Imports	0.5	0.5	1.1	1.2
Supply from Renewable Sources	0.8	0.9	1.0	1.1
Other - (NGL Production, Refinery Processing Gain)	3.2	3.2	3.5	3.7
Total Domestic Petroleum Consumption	19.1	19.1	20.0	20.5

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 October 2010 and is derived from information published by the EIA (see EIA website at [www.eia.doe.gov](http://www.eia.doe.gov)) (in millions of barrels per day).

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<b>Petroleum Administration Defense District</b>	<b>Regional Supply</b>	<b>Refinery Demand</b>	<b>Supply Shortfall</b>
PADD I (East Coast)	0.0	1.1	(1.1)
PADD II (Midwest)	0.7	3.3	(2.6)
PADD III (South)	3.2	7.3	(4.1)
PADD IV (Rockies)	0.4	0.6	(0.2)
PADD V (West Coast)	1.2	2.3	(1.1)
Total U.S.	5.5	14.6	(9.1)

Although PADD III has the largest absolute volume supply shortfall, we believe PADD II is the most critical region with respect to supply and transportation logistics because it is the largest, most highly populated area of the U.S. that does not have direct access to oceanborne cargoes.

From 1985 until 2004, crude oil production in PADD II has declined from approximately 1.1 million barrels per day to approximately 440,000 barrels per day. Over this same time period, refinery demand has increased from approximately 2.7 million barrels per day in 1985 to 3.3 million barrels per day in 2004. As a result, the volume of crude oil transported into PADD II has increased approximately 75% in absolute terms or 3.0% annually from 1.7 million barrels per day to 3.0 million barrels per day. This aggregate shortfall was principally supplied by direct imports from Canada to the north and from the Gulf Coast area and the Cushing Interchange to the south.

Starting in 2005, PADD II production began to grow and as of early 2011 is currently estimated to be over 700,000 barrels per day, driven mainly by increased production from the Bakken oil formation in North Dakota. This production growth is in an isolated part of the country, which has created its own infrastructure challenges and opportunities. Both the incremental Canadian oil production growth and the PADD II growth have generally targeted the Cushing & Patoka crude oil hubs. This has resulted in a decline in volumes moved from the Gulf Coast area into PADD II, but an increase in demand for storage at Cushing and Patoka.

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

- The multi-year trend narrowing the gap between supply and demand;
- Temporal increases in the gap related to supply response following price spikes and declines in the rate of demand growth due to worldwide economic slowdown;
- Regional supply and demand imbalances;
- Political instability in critical producing nations;

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- Policy decisions made by various governments around the world attempting to navigate energy challenges; and
- Significant fluctuations in absolute price as well as grade and location differentials.

The complexity and volatility of the crude oil market creates opportunities to solve the logistical inefficiencies inherent in the business.

### *Refined Products Market Overview*

Once crude oil is transported to a refinery, it 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.

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.

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

Demand for refined products has generally been affected by price levels, economic growth trends and, to a lesser extent, weather conditions. According to the EIA, consumption of refined products in the United States has risen from approximately 15.7 million barrels per day in 1985 to a peak in 2005 of 20.8 million barrels, yielding an average annual increase of approximately 1.5%. Due to the economic weakness of the last several years, refined product demand decreased to 18.8 million barrels per day in 2009, or an approximate 10% decrease over peak demand levels. Given this decreased demand for refined products and resulting excess refining capacity, a number of U.S. refineries reduced output and, in some cases, indefinitely closed. Demand for refined products has resumed growth in 2010 with consumption reaching approximately 19.1 million barrels per day for the twelve months ended October 2010. The EIA is currently forecasting growth in refined product demand for the next several years. The level of future demand growth will be influenced by the slope of the economic recovery and absolute prices. We believe that this projected demand growth will be met primarily by the increase in mandated alternative fuels, increased utilization of existing refining capacity as well as increased imports of refined products, the combination of which we believe will continue to generate demand for midstream infrastructure, including pipelines and terminals. We believe that demand for refined products pipeline and terminalling infrastructure will also be driven by the following factors:

- multiple specifications of existing products (also referred to as boutique gasoline blends);
- continued specification changes to existing products, such as lower sulfur limits; and
- increased acceptance and mandates of biofuels and other related renewable fuels.

The complexity and volatility of the refined products market creates opportunities to solve the logistical challenges inherent in the business.

***LPG Products Market Overview***

LPGs are hydrogen-based gases that are derived from crude oil refining and natural gas processing and include propane, butane and isobutane. These gases liquefy at moderate pressures thus allowing transportation and storage opportunities. LPG is produced domestically or imported into the U.S. from Canada and other parts of the world. Individual LPG products have varying uses. For example, propane is used in domestic applications (home heating and cooking), industrial applications, agricultural applications (crop drying) and as an automotive fuel. Normal butane is used as a petrochemical feedstock, as a blendstock for motor gasoline, and to derive isobutane through isomerization. Isobutane is principally used in refinery alkylation to enhance the octane content of motor gasoline or in the production of iso-octane or other octane additives. Certain LPGs are also used as diluents in the transportation of heavy oil, particularly in Canada.

The LPG market is driven by:

- seasonal shifts in weather;
- seasonal changes in gasoline specifications affecting demand for butane;
- alternating needs of refineries to store and blend LPG;
- petro-chemical demand;
- diluent requirements for Canadian heavy oil; and
- inefficiencies caused by regional supply and demand imbalances.

The complexity and volatility of the LPG market creates opportunities to solve the logistical inefficiencies inherent in the business.



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*Natural Gas 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.

The long-term demand for storage services in the United States is driven primarily by the long-term demand for natural gas and the overall lack of balance between the supply of and demand for natural gas on a seasonal, monthly, daily or other basis. In general and on a long term basis, to the extent the overall demand for natural gas increases and such growth includes higher demand from seasonal or weather-sensitive end-users (such as gas-fired power generators and residential and commercial consumers), demand for natural gas storage services should also grow. In addition, any factors that contribute to more frequent and severe imbalances between the supply of and demand for natural gas, whether caused by supply or demand fluctuations, should increase the need for and the value of storage services. On a short term basis, storage demand and values are also significantly influenced by operational imbalances, near term seasonal spreads, shorter term spreads and basis differentials.

*Natural Gas Demand.* During the period from 2001 through 2010, domestic natural gas consumption has grown, albeit unevenly, driven primarily by growth in the seasonal and weather-sensitive electric power generation and commercial sectors, offset by declines in the residential and industrial sectors.

*Natural Gas Supply.* For a number of years during the last decade, domestic natural gas production was relatively flat and has failed to keep pace with domestic consumption. Over the past few years, however, domestic natural gas production has been growing. This trend reversal is primarily due to increases in production from developing shale resource plays. According to EIA data, domestic production of natural gas increased by an average of approximately 3.7% per annum during the four-year period beginning January 1, 2007 through December 31, 2010.

By comparison, EIA data also indicates that 2009 production from shale gas wells was approximately 3.1 trillion cubic feet ( Tcf ), representing an approximate 142% increase over 2007 levels. At the time of this report, 2010 production estimates by component (i.e. shale gas) were not available from EIA.

In addition to the emergence of domestic shale plays as a significant supply source, over the past several years, the U.S. has developed significant infrastructure for the import of liquefied natural gas ( LNG ). Total LNG import capacity of U.S. infrastructure has increased to approximately 14 Bcf per day; however, because LNG suppliers have been able to obtain more favorable prices in global markets outside of the U.S., LNG imports into the U.S. have decreased from a peak of 2.1 Bcf a day in 2007 to less than 1.2 Bcf per day in 2009 and 2010, per EIA and other published daily data sources.

*Market Balance and Volatility.* The seasonality of natural gas has remained strong during the last decade, with consumption during the peak winter months averaging approximately 40% more than consumption during the summer months, per EIA data. Natural gas storage (and to a lesser extent imported natural gas from Canada and LNG supplies) 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 as a warehouse for gas production in excess of daily demand during low demand periods. This seasonal consumption pattern is a major driver of demand for gas storage and the price difference, or spread, between the summer and winter season provides a proxy for the fundamental value of storage.

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During most of the past decade, this strong seasonal trend has produced seasonal spreads that have generally moved within a range of approximately \$0.50-\$4.75 per MMBtu, with the high end of that range occurring during the 2006-2007 timeframe. However, during the past six months, seasonal spreads fell to as low as \$0.43, their lowest point since 2004. In addition, lower short-term spreads and basis differentials have reduced overall market volatility, which negatively impacts storage demand and value. While there are a variety of factors that have contributed to these softer market conditions, we believe the key drivers are (i) relatively flat natural gas consumption over the last year and projected flat consumption for the next two years, (ii) increased natural gas supplies due to production from shale resources, (iii) lower basis differentials due to expansion of natural gas transportation infrastructure in the U.S. over the last five years, and (iv) abnormal seasonal weather patterns resulting in decreased seasonal price spreads.

*Supply of Storage Capacity.* Another important factor in determining the value of storage is whether there is a surplus or shortfall of storage capacity relative to the overall demand for storage services in a given market area. In general, on a relative basis, storage values will be lower in markets that are oversupplied with storage than in markets where storage capacity is in short supply. The extent to which markets are oversupplied or undersupplied will fluctuate based on capacity additions and in response to significant variations in natural gas supply and demand.

While it is difficult to predict when, and how much, new capacity will be added to the market in the next few years, we believe that certain of the supply and demand factors contributing to the current softness in the storage market (i.e., robust supply levels, lower natural gas demand levels and reduced price volatility) are cyclical and self correcting over time, and that the long term outlook for storage utilization and demand is positive.

### **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 transportation, terminalling and storage facilities at major market hubs and in key oil producing basins and crude oil, refined product and LPG transportation corridors in the United States and Canada.

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

***Transportation Segment***

Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and refined products on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third party leases of pipeline capacity and transportation fees. Our transportation segment also includes our equity earnings from our investments in Butte, Frontier, Settoon Towing and White Cliffs, in which we own noncontrolling interests.

As of December 31, 2010, we employed a variety of owned or leased long-term physical assets throughout the United States and Canada in this segment, including approximately:

- 16,000 miles of active crude oil and refined products pipelines and gathering systems;
- 25 million barrels of active, above-ground tank capacity used primarily to facilitate pipeline throughput;
- 56 trucks and 352 trailers; and
- 65 transport and storage barges and 39 transport tugs through our interest in Settoon Towing.

The following is a tabular presentation of our active pipeline assets in the United States and Canada as of December 31, 2010, grouped by geographic location:

Region / Pipeline and Gathering Systems (1)	System Miles	2010 Average Net Barrels per Day (2) (in thousands)
<b><u>Southwest US</u></b>		
Basin	519	378
Permian Basin Area Systems	3,085	371
Other	406	141
<b>Southwest US Subtotal</b>	<b>4,010</b>	<b>890</b>
<b><u>Western US</u></b>		
All American	138	39

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Line 63/Line 2000	426	109
Other	148	83
<b>Western US Subtotal</b>	<b>712</b>	<b>231</b>
<b><u>US Rocky Mountain</u></b>		
Salt Lake City Area Systems	708	135
Other	3,857	280
<b>US Rocky Mountain Subtotal</b>	<b>4,565</b>	<b>415</b>
<b><u>US Gulf Coast</u></b>		
Capline(3)	631	223
Other	924	322
<b>US Gulf Coast Subtotal</b>	<b>1,555</b>	<b>545</b>
<b><u>Central US Subtotal</u></b>	<b>2,462</b>	<b>350</b>
<b>Domestic Total</b>	<b>13,304</b>	<b>2,431</b>
<b><u>Canada</u></b>		
Rangeland	1,214	52
Rainbow	594	187
Manito	559	61
Other	633	158
<b>Canada Total</b>	<b>3,000</b>	<b>458</b>
<b>Grand Total</b>	<b>16,304</b>	<b>2,889</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 of 2010.

(3) Non-operated pipeline.

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**Southwest US**

*Basin Pipeline System.* We own an approximate 87% undivided joint interest in and act as 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 is a 519-mile mainline, telescoping crude oil system with a system capacity ranging from approximately 144,000 barrels per day to 400,000 barrels per day depending on the segment. System throughput (as measured by system deliveries) was approximately 378,000 barrels per day (attributable to our interest) during 2010.

The Basin system consists of four primary movements of crude oil: (i) barrels that are shipped from Jal, New Mexico to the West Texas markets of Wink and Midland; (ii) barrels that are shipped from Midland to connecting carriers at Colorado City; (iii) barrels that are shipped from Midland and Colorado City to connecting carriers at either Wichita Falls or Cushing and (iv) foreign and Gulf of Mexico barrels that are delivered into Basin at Wichita Falls and delivered to connecting carriers at Cushing. The system also includes approximately 6 million barrels of tankage located along the system. The Basin system is subject to tariff rates regulated by the FERC.

We recently approved an expansion project on the Basin system to increase pipeline capacity on crude oil movements from Colorado City, Texas to Cushing, Oklahoma to approximately 450,000 barrels per day. The project is expected to be completed in the first quarter of 2012.

*Permian Basin Area Systems.* We operate wholly owned systems of approximately 3,000 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, Texas. These systems are subject to tariff rates regulated by either the FERC or state regulatory agencies. For 2010, combined throughput on the Permian Basin area systems totaled an average of approximately 371,000 barrels per day.

**Western US**

*All American Pipeline System.* We own a 100% interest in the All American Pipeline system. The All American Pipeline is a common carrier crude oil pipeline system that transports crude oil produced from two outer continental shelf, or OCS, fields offshore California via connecting pipelines to refinery markets in California. The system at Las Flores receives crude oil from ExxonMobil's Santa Ynez field, while the system at Gaviota receives crude oil from the Plains Exploration and Production Company-operated Point Arguello field. These systems both terminate at 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 in decline (as reflected in the table below). See Item 1A. Risk Factors for discussion of the estimated impact of a decline in volumes.



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The table below sets forth the historical volumes received from both of these fields for the past five years (barrels in thousands):

	For the Year Ended December 31,				
	2010	2009	2008	2007	2006
Average daily volumes received from:					
Point Arguello (at Gaviota)	6	6	7	8	9
Santa Ynez (at Las Flores)	33	34	38	38	40
Total	39	40	45	46	49

*Line 63.* We own a 100% interest in the Line 63 system. The Line 63 system is an intrastate common carrier crude oil pipeline system that transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin and in Bakersfield. The Line 63 system consists of a 144-mile trunk pipeline (of which 102 miles is 14-inch pipe and 42 miles is 16-inch pipe), 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 5 miles of distribution pipelines in the Los Angeles Basin, with a throughput capacity of approximately 144,000 barrels per day, and 148 miles of gathering pipelines in the San Joaquin Valley, with a throughput capacity of approximately 72,000 barrels per day. We also have 26 storage tanks with approximately 1 million barrels of storage capacity on this system. These storage assets are used primarily to facilitate the transportation of crude oil on the Line 63 system.

During the fourth quarter of 2009, a 71-mile segment of Line 63 was temporarily taken out of service to allow for certain repairs and realignments to be performed. Line 63 volumes are currently being redirected from the north end of this out-of-service segment to the parallel Line 2000. The product is then batched along Line 2000 until it is re-injected into the active portion of Line 63, which is south of the out-of-service segment, for subsequent delivery to customers. This temporary pipeline segment closure and redirection of product has not impacted our normal throughput levels on this line. For 2010, combined throughput on Line 63 totaled an average of approximately 51,000 barrels per day.

*Line 2000.* We own and operate 100% of Line 2000, an intrastate common carrier crude oil pipeline that originates at our Emidio Pump Station (part of the All American Pipeline System) and transports crude oil produced in the San Joaquin Valley and California OCS to refineries and terminal facilities in the Los Angeles Basin. Line 2000 is a 130-mile, 20-inch trunk pipeline with a throughput capacity of 130,000 barrels per day. During 2010, throughput on Line 2000 averaged approximately 58,000 barrels per day.

**US Rocky Mountain**

*Salt Lake City Area Systems.* We operate the Salt Lake City Area systems, in which we own between 75% and 100% interests. The Salt Lake City Area systems include interstate and intrastate common carrier crude oil pipeline systems that transport crude oil produced in Canada and the U.S. Rocky Mountain region to refiners in Salt Lake City, Utah and to other pipelines at Ft. Laramie, Wyoming. The Salt Lake City Area systems consist of 708 miles of pipelines and approximately 1 million barrels of storage capacity. The Salt Lake City Area systems have a combined throughput capacity of approximately 120,000 barrels per day to Salt Lake City and 20,000 barrels per day to Ft. Laramie. For 2010, throughput on the Salt Lake City Area Systems in total averaged approximately 135,000 barrels per day.

**US Gulf Coast**

*Capline Pipeline System.* The Capline Pipeline system is a 631-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. In October 2010, we purchased an additional undivided 11% interest in the Capline Pipeline System which increased our aggregate undivided joint interest to approximately 54%. We also own a 100% interest in 720,000 barrels of tankage located at Patoka, Illinois.

The Capline Pipeline system is one of the primary transportation routes for crude oil shipped into the Midwestern U.S., serving approximately 3 million barrels of refining capacity in PADD II. Shell Pipeline Company LP is the operator of this system through August 2013. Capline has direct connections to a significant amount of crude production in the Gulf of Mexico. In addition, with its two active docks capable of handling approximately 600,000-barrel tankers as well as access to



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the Louisiana Offshore Oil Port and our St. James terminal, it is a key transporter of sweet and light sour foreign crude to PADD II. Total designed operating capacity is approximately 1 million barrels per day of crude oil. In connection with the purchase of our additional undivided interest in the system, our attributable interest in this operating capacity has increased from approximately 470,000 barrels per day to approximately 600,000 barrels per day. Throughput on our interest averaged approximately 223,000 barrels per day during 2010.

**Canada**

*Rangeland System.* We own a 100% interest in the Rangeland system, which includes the Mid Alberta Pipeline ( MAPL ) and the Rangeland Pipeline. The Rangeland system consists of a 554 mile, 8-inch to 16-inch mainline pipeline and 660 miles of 3-inch to 8-inch gathering pipelines. Rangeland transports butane, condensate, light sweet crude and light sour crude either north to Edmonton, Alberta by MAPL or south to the U.S./Canadian border near Cutbank, Montana, where it connects to our Western Corridor system. On April 1, 2010, we successfully reversed MAPL allowing for flow from Rangeland's Sundre, Alberta terminal directly to Edmonton, Alberta. During 2010, Plains built and commissioned 80,000 barrels of tankage bringing our storage capability at Edmonton to 400,000 barrels. Total average throughput during 2010 on the Rangeland system was approximately 52,000 barrels per day.

*Rainbow System.* We own a 100% interest in the Rainbow system. The Rainbow system consists of a 480-mile, 20-inch to 24-inch mainline crude oil pipeline extending from the Norman Wells Pipeline located in Zama, Alberta to Edmonton, Alberta and 114 miles of gathering pipelines. During 2009, we added a heavy oil truck terminal at Nipisi, Alberta to provide producers with additional access to Rainbow. The system has a throughput capacity of approximately 220,000 barrels per day and transported approximately 187,000 barrels per day during 2010.

*Manito.* We own a 100% interest in the Manito heavy oil system. This 559-mile system is comprised of the Manito pipeline, the North Sask pipeline and the Bodo/Cactus Lake pipeline. Each system consists of a blended crude oil line and a parallel diluent line which delivers condensate to upstream blending locations. The North Sask pipeline is 84 miles in length and originates near Turtleford, Saskatchewan and terminates in Dulwich, Saskatchewan. The Manito pipeline includes 339 miles of pipeline, the mainline segment originates at Dulwich and terminates at Kerrobert, Saskatchewan. The Bodo/Cactus Lake pipeline is 136 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. At the end of 2009, Plains made the necessary changes to the Kerrobert terminal to expand the flexibility whereby we can now both receive and deliver heavy crude from and to the Enbridge pipeline system. For 2010, approximately 61,000 barrels per day of crude oil were transported on the Manito system.

**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, LPG and natural gas, as well as LPG fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements. Revenues generated in this segment include (i) storage fees that are generated when we lease storage capacity, (ii) terminalling fees, or throughput fees, that are generated when we receive crude oil, refined products, LPG or natural gas from one connecting pipeline and redeliver the applicable product to another connecting carrier, (iii) hub service fees for the movement of natural gas across our header systems, and (iv) fees from LPG fractionation and isomerization services.

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As of December 31, 2010, we owned, operated and employed a variety of long-term physical assets throughout the United States and Canada in this segment, including:

- approximately 59 million barrels of crude oil and refined products capacity primarily at our terminalling and storage locations;
- approximately 6 million barrels of LPG storage capacity;
- approximately 50 Bcf of natural gas storage working capacity;
- approximately 11 Bcf of base gas in storage facilities owned by us; and
- a fractionation plant in Canada with a processing capacity of 4,400 barrels per day, and a fractionation and isomerization facility in California with an aggregate processing capacity of 26,000 barrels per day.

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As of December 31, 2010, we were in the process of constructing approximately 4 million barrels of additional above-ground crude oil and refined product terminalling and storage capacities and an additional 18 Bcf of high-deliverability salt-cavern natural gas storage capacity.

The following is a tabular presentation of our active facilities segment storage assets in the United States and Canada as of December 31, 2010, grouped by product type:

Facility	Capacity (in millions of barrels, except where noted)
<b>Crude Oil and Refined Products</b>	
<i>Cushing</i>	14
<i>Kerrobert</i>	1
<i>LA Basin</i>	8
<i>Martinez and Richmond</i>	5
<i>Mobile and Ten Mile</i>	3
<i>Patoka</i>	5
<i>Philadelphia Area</i>	4
<i>St. James</i>	7
<i>Other</i>	12
<b>Subtotal</b>	<b>59</b>
<b>LPG</b>	
<i>Bumstead</i>	2
<i>Tirzah</i>	1
<i>Other</i>	3
<b>Subtotal</b>	<b>6</b>
<b>Natural Gas</b>	
<i>Pine Prairie</i>	24 Bcf
<i>Bluewater</i>	26 Bcf
<b>Subtotal</b>	<b>50 Bcf</b>

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

**Major Facilities Assets****Crude Oil and Refined Products**

*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 U.S. 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 primary source of refinery feedstock for the Midwest refiners and plays an integral role in establishing and maintaining markets for many varieties of foreign and domestic crude oil. Our Cushing Terminal was constructed in 1993, with an initial tankage capacity of 2 million barrels, to capitalize on the crude oil supply and demand imbalance in the Midwest. The facility is designed to handle multiple grades of crude oil while minimizing the interface and enabling deliveries

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to connecting carriers at their maximum rate. The facility also incorporates numerous environmental and operational safeguards that distinguish it from other facilities at the Cushing Interchange.

Since 1999, we have completed multiple expansions, which increased the capacity of the Cushing Terminal to a total of approximately 14 million barrels. During the first quarter of 2010, we placed into service four 570,000-barrel tanks, and during the fourth quarter of 2010 completed construction on four additional 270,000-barrel tanks. See Crude Oil Storage Facilities Under Construction and Under Development below for discussion of ongoing expansion activities at this facility.

*Kerrobert Terminal.* We own a crude oil and condensate storage and terminalling facility, which is located near Kerrobert, Saskatchewan and is connected to our Manito and Cactus Lake pipeline systems. The total storage capacity at the Kerrobert terminal is approximately 1 million barrels.

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*L.A. Basin.* We own five crude oil and refined product storage facilities in the Los Angeles area with a total of 8 million barrels of useable storage capacity and a distribution pipeline system of approximately 70 miles of pipeline in the Los Angeles Basin. Approximately 7 million barrels of the storage capacity are used for commercial service and 1 million barrels are used primarily for throughput to other storage tanks and for displacement oil and do not generate revenue independently. 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, our Line 2000 pipeline, and third-party pipelines and marine terminals in the Los Angeles Basin.

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

*Mobile and Ten Mile Terminal.* We have a marine terminal in Mobile, Alabama (the Mobile Terminal) that has current useable capacity of approximately 2 million barrels. Approximately 3 million barrels of additional storage capacity is available at our nearby Ten Mile Facility through a 36-inch pipeline connecting the two facilities, of which approximately two-thirds of the storage capacity is included within the transportation segment.

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

*Patoka Terminal.* Our Patoka Terminal has approximately 5 million barrels of storage capacity and the associated manifold and header system at the Patoka Interchange located in southern Illinois. During 2010, we completed Phase II and III storage capacity expansion projects adding 600,000 barrels and 800,000 barrels, respectively. Patoka is a growing regional hub with access to domestic and foreign crude oil volumes moving north on the Capline system as well as Canadian barrels moving south. See *Crude Oil Storage Facilities Under Construction and Under Development* below for discussion of ongoing expansion activities at this facility.

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

*St. James Terminal.* We have approximately 7 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 also includes a manifold and header system that allows for receipts and deliveries with connecting pipelines at their maximum operating capacity. Over the past two years, we completed the construction of a marine dock that is able to receive both barges and tankers, as well as Phase II of our expansion project adding approximately 900,000 barrels of storage capacity.

**Crude Oil Storage Facilities Under Construction and Under Development**

*Cushing Terminal & Mid-Continent Area.* Late in 2010, we began construction on additional crude oil tankage at our Cushing Terminal at an estimated cost of \$85 million. The project, which consists of three phases, includes adding a new pipeline interconnect and approximately 4 million barrels of storage capacity through the construction of sixteen 270,000 barrel tanks. Construction of Phases IX, X and XI are supported by long-term customer commitments and are expected to be placed in service by the end of 2011.

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*Patoka Terminal.* Early in 2011, we approved construction of Phase IV at our Patoka Terminal. This project will include the construction of two 300,000 barrel crude oil tanks and will increase the total storage capacity at Patoka to approximately 5 million barrels. This new tankage is expected to be completed in the first quarter of 2012 at an approximate cost of \$18 million.

*Pier 400.* This is a project to develop a deepwater petroleum import terminal at Pier 400 and Terminal Island in the Port of Los Angeles to handle marine receipts of crude oil and refinery feedstocks. As currently envisioned, the project would include a deep water berth, high capacity transfer infrastructure and storage tanks, with a pipeline distribution system that will connect to various customers.

The project Environmental Impact Report ( EIR ) was approved by the Board of Harbor Commissioners of the Port of Los Angeles on November 20, 2008. The EIR was challenged and on January 19, 2010, a final court ruling was issued in our favor. Construction of the Pier 400 project is still subject to the completion and execution of a land lease with the Port of Los Angeles and the receipt of certain other regulatory approvals, as well as the completion of commercial arrangements with potential customers. Currently, future costs to develop this project are estimated to be in the \$450 to \$550 million range. We currently have approximately \$45 million of capitalized project costs on our balance sheet as of December 31, 2010. We expect to be in a position in 2011 to determine whether or not we will move forward with the Pier 400 project.

**LPG Storage Facilities**

*Bumstead.* The Bumstead facility is located at a major rail transit point near Phoenix, Arizona. With 133 million gallons of working capacity (approximately 100 million gallons, or approximately 2 million barrels, of useable capacity), the facility's primary assets include three salt-dome storage caverns, a 24-car rail rack and six truck racks.

During 2010, we began upgrading and improving our Bumstead LPG storage facility, which will increase the useable capacity by approximately 700,000 barrels. This project is expected to be completed late in 2011 at a total cost of approximately \$19 million.

*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 and is connected to the Dixie Pipeline System (a third-party system) via our 62-mile pipeline.

**LPG Processing**

*Shafter.* Our Shafter facility located near Bakersfield, California provides isomerization and fractionation services to producers and customers of NGL. The primary assets consist of 200,000 barrels of NGL storage and a processing facility with butane isomerization capacity of 14,000 barrels per day and NGL fractionation capacity of 12,000 barrels per day. During the first quarter of 2011, we approved our Shafter Expansion Project. This project will include the construction of a 15-mile LPG pipeline system that will be capable of delivering up to 10,000 barrels per day from Occidental Petroleum Corporation's Elk Hills Gas plant to our Shafter facility. It will also include enhancements to our storage and rail facilities. The project is expected to be placed into service in the third quarter of 2012 at an anticipated investment of approximately \$50 million. We expect to invest approximately \$30 million during 2011.





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**Natural Gas Storage Facilities**

*Pine Prairie.* As a strategically located, high-deliverability storage facility, Pine Prairie has attracted a diverse group of customers, including utilities, pipelines, producers, power generators, marketers and LNG importers, whose storage needs include both traditional seasonal storage services and short-term storage services. Pine Prairie is strategically positioned relative to several major market hub.

Additionally, in January 2011, the CME Group, which is the owner of the NYMEX, announced the introduction of three new natural gas futures contracts for physical delivery at Pine Prairie. The contracts began trading in February 2011 on the NYMEX floor and electronically through CME Globex and will be available for clearing services through CME ClearPort.

Pine Prairie's pipeline header system, which includes an aggregate of 74 miles of 24-inch diameter pipe located within a 20-mile radius of Pine Prairie, is directly connected to eight large-diameter interstate pipelines through nine interconnects that service both conventional and unconventional natural gas production in Texas and Louisiana, including production from existing and emerging shale plays, as well as Gulf of Mexico production and LNG imports. These interconnects also provide direct or indirect access to each of the market hubs described above and to consumer and industrial markets in the Gulf Coast, Midwest, Northeast and Southeast regions of the United States.

Pine Prairie has a total current working gas storage capacity of 24 Bcf in three caverns, and planned expansions that will increase Pine Prairie's total capacity to 42 Bcf by mid-2012 and 45 Bcf by mid-2016. Subject to market demand, project execution, sufficient pipeline capacity, available financing and receipt of future permits, we have the property rights and operational capacity to expand our Pine Prairie facility significantly beyond our current permitted capacity of 48 Bcf. Taking these considerations into account and with certain infrastructure modifications, we currently estimate that Pine Prairie could support in excess of 15 salt caverns and an aggregate storage capacity of over 150 Bcf.

In October 2010, we filed an application for a permit from the FERC to expand Pine Prairie's working capacity up to 80 Bcf. The incremental 32 Bcf would be comprised of expanding four existing caverns by an aggregate 8 Bcf through low-cost fill and dewater operations and adding two additional caverns of 12 Bcf each, increasing the total caverns at Pine Prairie to seven caverns.

*Bluewater.* Bluewater is located in the State of Michigan which contains more underground natural gas storage capacity than any other state in the U.S. according to EIA data, and primarily services seasonal storage needs throughout Midwestern and Northeastern portions of the U.S. and the Southeastern portion of Canada. Accordingly, Bluewater's customers consist primarily of pipelines, utilities and marketers seeking seasonal storage services. Bluewater's 30-mile, 20-inch diameter pipeline header system connects with three interstate and three natural gas utility pipelines that provide access to the major market hubs of Chicago, Illinois and Dawn, Ontario, which supply natural gas to eastern Ontario and the northeastern United States. These interconnects also provide access to natural gas utilities that serve local markets in Michigan and Ontario.

Bluewater has total working gas storage capacity of approximately 26 Bcf in two depleted reservoirs and we expect to increase Bluewater's working gas capacity by 2 Bcf ratably over a 9 to 10-year period in connection with an ongoing liquids removal project. Bluewater also leases third-party storage capacity and pipeline transportation capacity from time to time to increase its operational flexibility and enhance its service offerings.

### **Recent Acquisition**

During February 2011, we closed the Southern Pines Acquisition. See *Acquisitions* and *Recent Developments* above for further information regarding the Southern Pines Acquisition and related transactions.

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

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

- the purchase of U.S. and Canadian crude oil at the wellhead and the bulk purchase of crude oil at pipeline and terminal facilities, as well as the purchase of foreign cargoes at their load port and various other locations in transit;
- the storage of inventory during contango market conditions and the seasonal storage of LPG;

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- the purchase of refined products and LPG from producers, refiners and other marketers;
- the resale or exchange of crude oil, refined products and LPG at various points along the distribution chain to refiners or other resellers to maximize profits; and
- the transportation of crude oil, refined products and LPG on trucks, barges, railcars, pipelines and ocean-going vessels to our terminals and third-party terminals.

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

In addition to substantial working inventories associated with its merchant activities, as of December 31, 2010, our supply and logistics segment also owned significant volumes of crude oil and LPG classified as long-term assets for linefill or minimum inventory requirements under service arrangements with transportation carriers and terminalling providers. The supply and logistics segment also employs a variety of owned or leased physical assets throughout the United States and Canada, including approximately:

- 9 million barrels of crude oil and LPG linefill in pipelines owned by us;
- 2 million barrels of crude oil and LPG linefill in pipelines owned by third parties and other long-term inventory;
- 530 trucks and 607 trailers; and
- 1,395 railcars.

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

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The following table shows the average daily volume of our supply and logistics activities for the year ended December 31, 2010 (in thousands of barrels per day):

	<b>Volumes</b>
Crude oil lease gathering purchases	620
LPG sales	96
Waterborne foreign crude oil imported	68
Supply & Logistics activities total	784

*Crude Oil and LPG Purchases.* We purchase crude oil and LPG from multiple producers under contracts and believe that we have established long-term, broad-based relationships with the crude oil and LPG producers in our areas of operations. These contracts generally range in term from a thirty-day evergreen to five years. The majority of these contracts, however, range in term from thirty-days to one year. We utilize our truck fleet and gathering pipelines as well as third-party pipelines, trucks and barges to transport the crude oil to market. In addition, we purchase foreign crude oil. Under these contracts we may purchase crude oil upon delivery in the U.S. or we may purchase crude oil in foreign locations and transport it on third-party tankers.

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We purchase LPG from producers, refiners, and other LPG marketing companies under contracts that generally range from immediate delivery to one year in term. We utilize our trucking fleet as well as leased railcars and third-party tank trucks or pipelines to transport LPG.

In addition to purchasing crude oil from producers, we purchase both domestic and foreign crude oil in bulk at major pipeline terminal locations and barge facilities. We also purchase LPG in bulk at major pipeline terminal points and storage facilities from major integrated oil companies, large independent producers or other LPG marketing companies. Crude oil and LPG is purchased in bulk when we believe additional opportunities exist to realize margins further downstream in the crude oil or LPG 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 LPG Sales.* The activities involved in the supply, logistics and distribution of crude oil and LPG are complex and require current detailed knowledge of crude oil and LPG sources and end markets and 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 LPG to the appropriate customer.

We sell our crude oil to major integrated oil companies, independent refiners and other resellers in various types of sale and exchange transactions. We sell LPG primarily to retailers and refiners, and limited volumes to other marketers. The contracts generally range in term from a thirty-day evergreen to four years. The majority of these contracts are at market price and have terms ranging from one month to one year. We establish a margin for the crude oil and LPG we purchase by entering into physical sales contracts with third parties, or by entering into a future delivery obligation with respect to futures contracts on the NYMEX, ICE or over-the-counter. Through these transactions, we seek to maintain a position that is substantially balanced between purchases and sales and future delivery obligations. From time to time, we enter into various types of sale and exchange transactions including fixed price delivery contracts, floating price collar arrangements, financial swaps and crude oil and LPG-related futures contracts as hedging devices.

*Crude Oil and LPG 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 LPG that more closely matches our physical delivery requirement, location or the preferences of our customers, we exchange physical crude oil or LPG, 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 LPG that differs in terms of geographic location, grade of crude oil or type of LPG, or physical delivery schedule from crude oil or LPG we have available for sale. Generally, we enter into exchanges to acquire crude oil or LPG 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.

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

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

Because our typical crude oil sales transactions can involve tens of thousands of barrels of crude oil, 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 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 LPG, natural gas and refined products; 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 LPG on a forward basis, as well as to sell LPG on a current basis to local distributors and retailers. In certain cases our LPG customers prepay for their purchases, in

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amounts ranging from approximately \$1 per barrel to 100% of their contracted amounts. Generally, sales of LPG and refined products settle within 10 days of the invoice date.

Certain activities in our supply and logistics segment are affected by seasonal aspects, primarily with respect to LPG supply and logistics activities, which generally have higher activity levels during the first and fourth quarters of each year.

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

Through our three business segments, we are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products, LPG 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, LPG, refined products and natural gas commodity prices have historically been very volatile. For example, over the last 24 years, NYMEX West Texas Intermediate crude oil benchmark prices have ranged from a low of approximately \$10 per barrel during 1986 to a high of over \$147 per barrel during 2008. More recently, crude oil prices traded as low as \$33 per barrel in early 2009, before increasing to a range of \$85 to \$95 per barrel in February 2011.

Absent extended periods of lower crude oil prices that are below production replacement costs or higher crude oil prices that have a significant adverse impact on consumption, demand for the services we provide in our fee based transportation and facilities segments and our gross profit from these activities have little correlation to absolute oil prices. Relative contribution levels will vary from quarter-to-quarter due to seasonal and other similar factors, but our fee based transportation and facilities segments should comprise approximately 75% 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 LPG at prices in excess of our aggregate cost. Although segment profit may be adversely affected during certain transitional periods, our crude oil supply, logistics and distribution operations are not directly affected by the absolute level of crude oil prices, but are affected by overall levels of supply and demand for crude oil and relative fluctuations in market-related indices.

In developing our business model and allocating our resources among our three segments, we attempt to anticipate the impacts of shifts between supply-driven markets and demand-driven markets, seasonality, cyclicalities, 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 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 line loss allowance barrels, and if crude oil prices are low relative to historical prices, we may hedge part of the fuel needed to operate our trucks and barges. Also, during periods when supply exceeds the demand for crude oil, LPG 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, LPG or natural gas at current prices for storage and simultaneously sell forward such products for future delivery at higher prices. Conversely, when there is a higher demand than supply of crude oil, LPG or natural gas in the near term, the market is backwardated, meaning that the price for future deliveries is lower than current prices. In a backwardated market, hedged positions established in a contango market can be unwound, with the physical product or futures position sold into the current higher priced market at a level that more than compensates for any loss associated with closing out future delivery obligations.

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



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***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. 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 of whether there is value 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 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. 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 (i) to purchase only product for which we have a market, (ii) to structure our sales contracts so that price fluctuations do not materially affect the segment profit we receive, and (iii) not to acquire and hold physical inventory, futures contracts or other derivative products for the purpose of speculating on outright commodity price changes.

Although we seek to maintain a position that is substantially balanced within our supply and logistics activities, we purchase crude oil, refined products, LPG 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 15 to our Consolidated Financial Statements.

**Customers**

Marathon Oil Corporation and its affiliates accounted for 14% of our revenues for each of the three years ended December 31, 2010, 2009 and 2008. ConocoPhillips Company accounted for 10%, 12% and 12% of our revenues for the years ended December 31, 2010, 2009 and 2008, respectively. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2010. The majority of revenues from these customers pertain to our supply and logistics operations. We believe that the loss of these customers would have only a short-term impact on our operating results. There is risk, however, that we would not be able to identify and access a replacement market at comparable margins. For a discussion of customers and industry concentration risk, see Note 8 to our Consolidated Financial Statements.

## Competition

Competition among pipelines is based primarily on transportation charges, access to producing areas and demand for the crude oil 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.

We also face competition with respect to our supply and logistics and facilities services. Our competitors include other crude oil pipeline 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 many times greater than ours, and control greater supplies of crude oil.

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 major pipeline companies and independent storage providers have existing storage facilities connected to their systems that compete with some of our facilities.

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**Regulation**

Our assets, operations and business activities are subject to extensive legal requirements and regulations under the jurisdiction of numerous federal, state, provincial and local agencies. Many of these agencies are authorized by statute to issue and have issued requirements binding on the pipeline industry, related businesses and individual participants. The failure to comply with such legal requirements and regulations can result in substantial 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. In 2010 we settled by means of separate Consent Decrees, two ongoing Department of Justice ( DOJ )/Environmental Protection Agency ( EPA ) proceedings regarding certain releases of crude oil. Although we believe that all material aspects of the injunctive elements of the Consent Decrees (costs and operational effects) have been incorporated into our budgeting and planning process, future proceedings could result in injunctive remedies, the effect of which would subject us to operational requirements and constraints that would not apply to our competitors. See Item 3. Legal Proceedings.

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

**Environmental, Health and Safety Regulation**

*General*

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons including crude oil are subject to stringent federal, state, provincial and local laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment. As with the industry generally, compliance with these laws and regulations increases our overall cost of doing business, including our capital costs to construct, maintain and upgrade equipment and facilities. Failure to comply with these laws and regulations could result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, and the issuance of injunctions that may subject us to additional operational constraints that our competitors are not required to follow. Environmental and safety laws and regulations are subject to changes that may result in more stringent requirements, and we cannot provide any assurance that compliance with current and future laws and regulations will not have a material effect on our results of operations or earnings. A discharge of hazardous liquids into the environment could, to the extent such event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and any claims made by third parties. The following is a summary of some of the environmental and safety laws and regulations to which our operations are subject.

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

A substantial portion of our petroleum pipelines and our storage tank facilities in the United States are subject to regulation by the Pipeline and Hazardous Materials Safety Administration ( the 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

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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.

The HLPSCA was amended by the Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act ( PIPES 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. Costs associated with the inspection, testing and correction of identified anomalies were approximately \$31 million in 2010, \$25 million in 2009 and \$23 million in 2008. Based on currently available information, our preliminary estimate for 2011 is that we will incur approximately \$12 million in operational expenditures and approximately \$25 million in capital expenditures associated with our pipeline integrity management program. The acquisitions we have completed over the last several years have included pipeline assets of varying ages and maintenance and operational histories. Accordingly, we will continue to focus on pipeline integrity management as a primary operational emphasis. 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 HLPSCA and the 2002 and 2006 amendments.

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In 2010, Congress began hearings on the reauthorization of the PIPES Act, which expired in September 2010. Congress did not complete the reauthorization process in 2010, so it will be deferred to 2011 for the new 112th Congress to consider. However, a lapse has no real effect on PHMSA regulation or programs as the pipeline safety program will continue at its previous funding levels. As part of the reauthorization process, on October 18, 2010, PHMSA issued an Advance Notice of Proposed Rulemaking ( ANPRM ). Within the ANPRM, PHMSA stated that it is considering whether changes are needed to the regulations covering hazardous liquid pipelines and is seeking public comment on six specific topic areas. The six topics include, (1) the scope of the pipeline safety regulations and existing regulatory exceptions, (2) the criteria for designation as a High Consequence Area ( HCA ), (3) leak detection and Emergency Flow Restricting Devices, (4) valve spacing, (5) repair criteria for non-HCA areas, and (6) Stress Corrosion Cracking. At this point we cannot predict what new requirements, if any, may come about as a result of reauthorization of the PIPES Act and PHMSA s ANPRM. Significant additional operating expenses could be incurred if new or more stringently interpreted pipeline safety requirements are implemented.

Effective July 2008, PHMSA amended its pipeline safety regulations to extend protection to designated unusually sensitive areas or USAs that could be damaged by failure of certain rural onshore hazardous liquid gathering lines or low-stress pipelines. These USAs include locations containing sole-source drinking water, endangered species, or other ecological resources. Operators of rural onshore hazardous liquid gathering lines located within a defined buffer area around a USA must comply with safety requirements to address threats of corrosion and third-party damage to their lines by developing a damage prevention program, complying with specified corrosion control requirements, and monitoring and mitigating conditions that could lead to internal corrosion. The amended rules narrow the regulatory exception for rural onshore low-stress hazardous liquid pipelines by extending existing safety regulations (including integrity management requirements) to certain low-stress pipelines within a defined buffer area around a USA. In June 2010, PHMSA proposed to extend the amended requirements to all remaining rural low-stress hazardous liquid pipelines that were not covered by the initial rulemaking. We have less than 300 miles of pipeline subject to the amended rules and do not expect compliance to have a material effect on our operating expenses.

In December 2009, PHMSA finalized a new rule dictating the shape and content of new control room management programs for hazardous liquid, gas transmission and distribution pipelines. The rule addresses human factors, including fatigue and other aspects of control room management for pipelines where controllers use supervisory control and data acquisition systems. The new rule became effective on February 1, 2010 and requires that control room management plans must be written by August 1, 2011 and implemented by February 1, 2013. In November 2010, PHMSA proposed to expedite program implementation for most of the rule s requirements to August 2011. We have already incorporated many of the new rule s requirements into our control room operations and we anticipate completing the revisions to our management plan and fully implementing the new provisions prior to the deadlines established in this new rule or prior to the proposed expedited deadline.

We have an internal review process in which we examine the condition and operating history of certain pipelines 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 U.S. EPA enforcement actions, we may elect (as a result of our own internal initiatives) to spend substantial sums to ensure the integrity of and upgrade our pipeline systems and, in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines.

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

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

The DOT has adopted American Petroleum Institute Standard 653 ( API 653 ) as the standard for the inspection, repair, alteration and reconstruction of steel aboveground petroleum storage tanks subject to DOT jurisdiction. API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Initial compliance, subject to an applicable waiver or stay, was required in May 2009. Costs associated with this program were approximately \$25 million, \$22 million and \$41 million in 2010, 2009 and 2008, respectively. For 2011, we have budgeted approximately \$26 million in connection with continued API 653 compliance activities and similar new EPA regulations for tanks not regulated by the DOT. Certain storage tanks may be taken out of service if we believe the cost of compliance will exceed the value of the storage tanks or replacement

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tankage may be constructed.

In Canada, the NEB and provincial agencies such as the Energy Resources Conservation Board ( ERCB ) in Alberta and the Saskatchewan Ministry of Energy and Resources regulate the construction, alteration, inspection and repair of crude oil storage tanks. We have incurred and will continue to incur costs under laws and regulations related to pipeline and storage tank integrity, such as operator competency programs, regulatory upgrades to our operating and maintenance systems and environmental upgrades of buried sump tanks. We spent approximately \$23 million in 2010, \$20 million in 2009 and \$8 million in 2008 on these types of costs. Our preliminary estimate for 2011 is approximately \$28 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. Asset acquisitions are an integral part of our business strategy. As we acquire additional assets, we may be required to incur additional costs in order to ensure that the acquired assets comply with the regulatory standards in the U.S. and Canada.

***Occupational Safety and Health***

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. 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.

Similar regulatory requirements exist in Canada under the federal and provincial Occupational Health and Safety Acts and related regulations. The agencies with jurisdiction under these regulations are empowered to enforce them through inspection, audit, incident investigation or public or employee complaint. 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 and provincial laws also impose liabilities for releases of certain substances into the environment.

***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.



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In conjunction with our acquisitions, we typically make an assessment of potential environmental exposure and determine whether to negotiate an indemnity, what the terms of any indemnity should be and whether to obtain environmental risk insurance, if available. These contractual indemnifications typically are subject to specific monetary requirements that must be satisfied before indemnification will apply, and have term and total dollar limits. For instance, in connection with the purchase of former Texas New Mexico ( TNM ) pipeline assets from Link Energy LLC ( Link ) in 2004, we identified a number of environmental liabilities for which we received a purchase price reduction from Link and recorded a total environmental reserve of \$20 million, of which we agreed in an arrangement with TNM to bear the first \$11 million in costs of pre-May 1999 environmental issues. TNM also agreed to pay all costs in excess of \$20 million (excluding certain deductibles). TNM s obligations are guaranteed by Shell Oil Products ( SOP ). As of December 31, 2010, we had incurred approximately \$19 million of remediation costs associated with these sites, while SOP s share has been approximately \$8 million.

Other assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified.

***Air Emissions***

Our operations are subject to the U.S. Clean Air Act ( Clean Air Act ) and comparable state and provincial laws. 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 state and regional air emissions control when we attempt to obtain or maintain permits and approvals for sources of air emissions. Although we believe that our operations are in substantial compliance with these laws in the areas in which we operate, we can provide no assurance that future compliance obligations will not have a material adverse effect on our financial condition or results of operations. For example, EPA has recently proposed a significant tightening of the national ambient air quality standards for ozone which, if adopted, could require significant reductions in emissions of volatile organic compounds and nitrogen oxides in regions of the U.S. that have not previously been subject to the most stringent emissions limitations.

***Climate Change Initiatives***

In response to recent studies suggesting that emissions of carbon dioxide, methane and certain other gases may be contributing to warming of the Earth s atmosphere, many nations, including Canada, have agreed to limit emissions of these gases, generally referred to as greenhouse gases ( GHG ), pursuant to the United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol. The Kyoto Protocol requires Canada to reduce its emissions of GHG to 6% below 1990 levels by 2012.

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 regulating industrial GHG emissions by establishing mandatory emissions reduction requirements on a sector basis. Originally, this framework was intended to be implemented by 2010, however no federally mandated reduction targets for GHGs have been implemented to date. Since 2004, companies emitting more than 100 thousand tonnes per year ( kt/y ) of CO<sub>2</sub> equivalent 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. The operations of Plains Midstream Canada ( PMC ) fall well below this 50 kt/y threshold.

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In Alberta, the provincial government implemented the *Specified Gas Emitters Regulation* in 2007 (under the Alberta Environmental and Protection and Enhancement Act), which mandated a 12% reduction in emission intensity over 2003-2005 levels for all facilities emitting more than 100 kt/y of CO<sub>2</sub>e. It is anticipated that the threshold for this regulation will be reduced in future years. Alberta also has a GHG reporting threshold at 50 kt/y of CO<sub>2</sub>e. Again, emissions from PMC's facilities are well below the 50 kt/y threshold.

In April 2010, Environment Canada proposed the *Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations* under the Canadian Environmental Protection Act (CEPA). Transportation is one of the largest sources of GHG emissions in Canada, accounting for about 27% of total GHG emissions in 2007. Passenger cars and light trucks account for approximately 12% of total GHG emissions or 45% of transportation emissions. The objective of the proposed regulations is to reduce GHG emissions by establishing mandatory GHG emission standards for new vehicles of the 2011 and later model years that are aligned with U.S. standards. The alignment of vehicle emission standards across North America will provide a level playing field for North American automobile manufacturers. The governments of Canada and the U.S. are consulting to develop aligned regulations to reduce emissions from heavy-duty trucks. In December 2010, the Canadian federal government finalized the *Renewable Fuel Regulations* under CEPA. These regulations require an annual average renewable content of five percent in gasoline and will require a two percent renewable content in diesel fuel and heating oil by 2011. These requirements are further intended to reduce GHG emissions in the transportation sector. No other regulatory initiatives to reduce GHG emissions in the truck transportation sector have been announced.

Draft regulations to reduce GHGs from the electricity sector are expected to be published in *Canada Gazette* early in 2011 and final regulations published later this year. This will allow sufficient time for consultations and outreach with industry and other stakeholders. Regulations are scheduled to come into effect on July 1, 2015. No other regulatory initiatives to reduce GHG emissions in the electricity sector have been announced.

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.

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The United States is not participating in the Kyoto Protocol, and, as a result of the November 2010 elections, it appears unlikely that the U.S. Congress will adopt significant climate change legislation within the next two years. However, numerous states already have begun implementing either GHG reporting requirements or actual measures to reduce GHG emissions through mechanisms such as regional cap-and-trade programs. There has also been considerable regulatory activity at the federal level even in the absence of new legislation. Some of the more notable federal actions are:

- In October 2009, EPA issued a rule requiring annual reporting of GHG emissions from stationary facilities.
- On December 15, 2009, EPA published a formal endangerment finding that sets the groundwork for GHG s to be regulated pollutants under the Clean Air Act.
- In May 2010, EPA and the National Highway Transportation Safety Administration (NHTSA) jointly issued rules setting GHG standards for light-duty vehicles.
- In June 2010, EPA issued a rule establishing major source thresholds and permitting requirements for large emitters of GHG s.
- In December 2010, EPA and NHTSA announced they would be proposing GHG standards for medium and heavy-duty vehicles.
- In January 2011, EPA began requiring state environmental agencies to specify GHG emission control requirements in permits for new or substantially modified sources of significant GHG emissions.

We anticipate that a small number of our facilities (less than ten) will be subject to the GHG reporting requirements in 2011 and 2012. These include facilities with combustion GHG emissions and potential fugitive emissions above the reporting thresholds, and we expect to report entity-wide GHG emissions on the basis of finished fuels that we import from outside of the U.S. 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 GHG credits or install control technology to reduce GHG emissions at any of our facilities.

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

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

### *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 11 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.

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

*State Regulation.* Our intrastate 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. See Note 12 to our Consolidated Financial Statements. The TRRC is subject to a sunset condition. If the Texas Legislature does not continue the TRRC, the TRRC will be abolished effective September 1, 2011 and will begin a one-year wind-down process. The Sunset Advisory Commission has recommended certain organizational changes be made to the TRRC. We cannot tell what, if any, changes will be made to the TRRC as a result of the pending regular session or any called sessions of the Texas Legislature in 2011, but we do not believe that any such changes would affect our business in a way that would be materially different from the way such changes would affect our competitors.

*Canadian Regulation.* Our Canadian pipeline assets are subject to regulation by the NEB and by provincial authorities, such as the Alberta ERCB. 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.

*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 ( BOEMRE )) 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 ( EAct ), 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. The current methodology (the producer price index for finished goods plus an adjustment factor of 1.3 percent) will remain in place through June 30, 2011. Effective July 1, 2011, the index for the next five year period will be the producer price index for

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finished goods plus an adjustment factor of 2.65 percent. Pipelines are allowed to raise their rates to the rate ceiling level generated by application of the index. If the methodology 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 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, agreement with an unaffiliated shipper, and settlement 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 that 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.