ENTERPRISE PRODUCTS PARTNERS L P
Form 10-K
February 29, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2011

OR

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

For the transition period from ___ to ___.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.
(Exact name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	76-0568219 (I.R.S. Employer Identification No.)

1100 Louisiana Street, 10th Floor, Houston, Texas (Address of Principal Executive Offices)	77002 (Zip Code)

(713) 381-6500
(Registrant's Telephone Number, Including Area Code)

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

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

Securities to be 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 þ No o

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

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 þ   No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, 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 þ   No o

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

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 definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of Enterprise Products Partners L.P.'s ("Enterprise") common units held by non-affiliates at June 30, 2011 was approximately $22.1 billion based on the closing price of such equity securities in the daily composite list for transactions on the New York Stock Exchange. This figure excludes common units beneficially owned by certain affiliates. There were 881,620,418 common units of Enterprise and 4,520,431 Class B units (which generally vote together with the common units) outstanding at February 1, 2012.

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KEY REFERENCES USED IN THIS ANNUAL REPORT

Unless the context requires otherwise, references to "we," "us," "our," "Enterprise" or "Enterprise Products Partners" a intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. References to "EPO" mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise, and its consolidated subsidiaries, through which Enterprise Products Partners L.P. conducts its business. Enterprise is managed by its general partner, Enterprise Products Holdings LLC ("Enterprise GP"), which is a wholly owned subsidiary of Dan Duncan LLC, a Delaware limited liability company.

On September 3, 2010, Enterprise GP Holdings L.P. ("Holdings"), Enterprise, Enterprise GP, Enterprise Products GP, LLC ("EPGP," the former general partner of Enterprise) and Enterprise ETE LLC ("Holdings MergerCo," a Delaware limited liability company and a wholly owned subsidiary of Enterprise) entered into a merger agreement (the "Holdings Merger Agreement"). On November 22, 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with and into Holdings MergerCo and related transactions were completed, with Holdings MergerCo surviving such merger (collectively, we refer to these transactions as the "Holdings Merger"). Enterprise's membership interests in Holdings MergerCo were subsequently contributed to EPO. As a result of completing the Holdings Merger, Enterprise GP, which had previously been the general partner of Holdings ("Holdings GP"), became Enterprise's general partner. For additional information regarding the Holdings Merger, see Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The membership interests of Dan Duncan LLC are owned of record by a voting trust, the current trustees ("DD LLC Trustees") of which are: (i) Randa Duncan Williams, who is also a director of Enterprise GP; (ii) Dr. Ralph S. Cunningham, who is also a director and the Chairman of Enterprise GP; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP. Each of the DD LLC Trustees also currently serves as one of the three managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust, the current trustees ("EPCO Trustees") of which are: (i) Ms. Williams, who also serves as Chairman of EPCO; (ii) Dr. Cunningham, who also serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who also serves as the President and Chief Executive Officer ("CEO") of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also directors of EPCO.

On April 28, 2011, we, our general partner, EPD MergerCo LLC ("Duncan MergerCo," a Delaware limited liability company and our wholly owned subsidiary), Duncan Energy Partners L.P. ("Duncan Energy Partners") and DEP Holdings, LLC ("DEP GP," the general partner of Duncan Energy Partners) entered into a definitive merger agreement (the "Duncan Merger Agreement"). On September 7, 2011, the Duncan Merger Agreement was approved by the unitholders of Duncan Energy Partners and the merger of Duncan MergerCo with and into Duncan Energy Partners and related transactions were completed, with Duncan Energy Partners surviving such merger as our wholly owned subsidiary (collectively, we refer to these transactions as the "Duncan Merger"). For additional information regarding the Duncan Merger, see Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

References to "TEPPCO" and "TEPPCO GP" mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their mergers with our subsidiaries on October 26, 2009. We refer to such related mergers both individually and in the aggregate as the "TEPPCO Merger."

References to "Employee Partnerships" mean EPE Unit L.P., EPE Unit II, L.P., EPE Unit III, L.P., Enterprise Unit L.P. and EPCO Unit L.P., collectively, all of which were privately held affiliates of EPCO. The Employee Partnerships were liquidated in August 2010.

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As generally used in the energy industry and in this annual report, the acronyms below have the following meanings:

/d	= per day	MMBbls	= million barrels
BBtus	= billion British thermal units	MMBPD	= million barrels per day
Bcf	= billion cubic feet	MMBtus	= million British thermal units
BPD	= barrels per day	MMcf	= million cubic feet
MBPD	= thousand barrels per day	TBtus	= trillion British thermal units

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This annual report on Form 10-K for the year ended December 31, 2011 (the "annual report") contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "will," "believe, similar expressions and statements regarding our plans and objectives for future operations are intended to identify forward-looking statements. Although we and our general partner believe that our expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions as described in more detail under Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this annual report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

PART I

Item 1 and 2. Business and Properties.

General

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO and are now a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States ("U.S."), Canada and the Gulf of Mexico with domestic consumers and international markets. Our assets include approximately 50,600 miles of onshore and offshore pipelines; 190 MMBbls of storage capacity for NGLs, crude oil, refined products and certain petrochemicals; and 14 Bcf of natural gas storage capacity.

Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminaling; crude oil and refined products transportation, storage, and terminaling; offshore production platforms; petrochemical transportation and services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. We have six reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas

Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; (v) Petrochemical & Refined Products Services; and (vi) Other Investments.

We conduct substantially all of our business through EPO and are owned 100% by our limited partners from an economic perspective. Enterprise GP owns a non-economic general partner interest in us. Our principal executive offices are located at 1100 Louisiana Street, 10th Floor, Houston, Texas 77002, our telephone number is (713) 381-6500 and our website address is www.enterpriseproducts.com.

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Business Strategy

We operate an integrated network of midstream energy assets. Our business strategies are to:

§ capitalize on expected increases in the production of natural gas, NGLs and crude oil from development activities in various producing basins including the Rocky Mountains, Midcontinent, Northeast and U.S. Gulf Coast regions, deepwater Gulf of Mexico and developing shale plays including the Barnett, Eagle Ford, Haynesville, Marcellus, Mancos and Utica Shales;

§ capitalize on expected demand growth for natural gas, NGLs, crude oil and petrochemical and refined products;

§ maintain a diversified portfolio of midstream energy assets and expand this asset base through growth capital projects and accretive acquisitions of complementary midstream energy assets;

§ enhance the stability of our cash flows by investing in pipelines and other fee-based businesses; and

§ share capital costs and risks through joint ventures or alliances with strategic partners, including those that will provide the raw materials for these growth capital projects or purchase the projects' end products.

As noted above, part of our business strategy involves expansion through growth capital projects. We expect that these projects will enhance our existing asset base and provide us with additional growth opportunities in the future.

Duncan Merger

In September 2011, the Duncan Merger Agreement was approved by the unitholders of Duncan Energy Partners and the merger of Duncan MergerCo and Duncan Energy Partners and related transactions were completed, with Duncan Energy Partners surviving such merger as our wholly owned subsidiary. Each issued and outstanding common unit of Duncan Energy Partners was cancelled and converted into the right to receive our limited partner common units based on an exchange ratio of 1.01 Enterprise common units for each Duncan Energy Partners common unit. We issued 24,277,310 of our common units (net of fractional common units cashed out) to the former public unitholders of Duncan Energy Partners as consideration in the Duncan Merger. We did not issue any common units as merger consideration to our subsidiaries that owned limited partner interests in Duncan Energy Partners.

Holdings Merger

In November 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with Holdings MergerCo and related transactions were completed, with Holdings MergerCo surviving such merger. At the effective time of the Holdings Merger, Enterprise GP succeeded as our general partner, and each issued and outstanding unit representing limited partner interests in Holdings was cancelled and converted into the right to receive our common units based on an exchange ratio of 1.5 Enterprise common units for each Holdings unit. We issued an aggregate of 208,813,454 of our common units (net of fractional common units cashed out) as consideration in the Holdings Merger and, immediately after the merger, cancelled 21,563,177 of our common units previously owned by Holdings.

In connection with the Holdings Merger, a privately held affiliate of EPCO agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from us with respect to a certain number of our common units (the "Designated Units") it owned over a five-year period after the merger closing date of November 22, 2010. The number of Designated Units to which the temporary distribution waiver applies is as follows for distributions paid or to be paid, if any, during the following calendar years: 30,610,000 during 2011; 26,130,000 during 2012; 23,700,000 during 2013; 22,560,000 during 2014; and 17,690,000 during 2015. Distributions paid to partners during calendar year 2011 excluded the initial 30,610,000 Designated Units; however, distributions to be paid, as applicable, to partners in calendar year 2012 (beginning with the February 2012 distribution) will exclude 26,130,000 Designated Units. As a result, the number of our distribution-bearing units increased by 4,480,000 units

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beginning with the February 2012 distribution and will increase in subsequent years as the number of Designated Units declines.

Basis of Financial Statement Presentation

As a result of the Holdings Merger, Enterprise's consolidated financial and operating results prior to November 22, 2010 have been presented as if Enterprise were Holdings from an accounting perspective (i.e., the financial statements of Holdings became the historical financial statements of Enterprise). See Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the basis of presentation of our general purpose financial statements. Such information is incorporated by reference into this Item 1 and 2 discussion.

Since we historically consolidated Duncan Energy Partners for financial reporting purposes, the Duncan Merger did not change the basis of presentation of our historical financial statements.

Significant Growth Capital Projects

An integral part of our business strategy involves expansion through growth capital projects, business combinations and investments in joint ventures. We believe that we are positioned to continue to expand our system of assets through the construction of new facilities and to capitalize on expected increases in the production of natural gas, NGLs and crude oil from development activities in various producing basins including the Rocky Mountains, Midcontinent, Northeast and U.S. Gulf Coast regions, deepwater Gulf of Mexico and developing shale plays including the Barnett, Eagle Ford, Haynesville, Marcellus, Mancos and Utica Shales. Our growth projects are typically supported by long-term producer and shipper dedications. We have a number of significant growth capital projects currently underway including the following:

§ In January 2012, we announced the receipt of sufficient transportation commitments to support development of our 1,230-mile Appalachia to Texas pipeline (the "ATEX Express") that will transport growing ethane production from the Marcellus and Utica Shale producing areas of Pennsylvania, West Virginia and Ohio to the U.S. Gulf Coast. We expect that the ATEX Express will begin commercial operations in the first quarter of 2014.

§ In January 2012, we announced the execution of crude oil transportation agreements with a consortium of six Gulf of Mexico producers that will provide the necessary support for construction of a 149-mile crude oil gathering pipeline serving the Lucius oil and gas field located in the southern Keathley Canyon area of the deepwater central Gulf of Mexico (the "SEKCO Oil Pipeline"). The SEKCO Oil Pipeline is expected to begin service by mid-2014.

§ In November 2011, we and Enbridge Inc. agreed to reverse the direction of crude oil flows on the Seaway pipeline to enable it to transport oil from the oversupplied Cushing hub to U.S. Gulf Coast refiners. The Seaway pipeline could operate in reversed service with an initial capacity of 150 MBPD during the second quarter of 2012. Following pump station additions and other modifications, which are anticipated to be completed in the first quarter of 2013, we anticipate the capacity of the reversed Seaway pipeline will be up to 400 MBPD (assuming a mix of light and heavy grades of crude oil). In addition, we are constructing related storage assets and connecting pipelines in the Houston, Texas area that are expected to be completed in mid-2012 and early 2014, respectively.

§ In November 2011, we announced several new construction projects, including an expansion of our new Yoakum natural gas processing facility, which would extend and expand our natural gas and NGL infrastructure in South Texas to accommodate expected production growth from the Eagle Ford Shale. We expect the Yoakum facility and related assets to commence operations in phases beginning in the second quarter of 2012 and continuing into the first quarter of 2013. In addition to the Yoakum expansion, we are constructing 62 miles of natural gas pipeline loops and increasing our pipeline compression to gather and transport additional quantities of liquids-rich gas from the Eagle Ford Shale. These pipeline expansion projects are also expected to begin service in the first quarter of 2013.

§ In November 2011, commercial operations on the Haynesville Extension of our Acadian Gas System commenced. As a result of completing the Haynesville Extension project, we have provided producers in Louisiana's Haynesville and Bossier Shale plays with access to 1.8 Bcf/d of incremental natural gas takeaway capacity.

§ In September 2011, we, along with Enbridge Energy Partners, L.P. ("Enbridge") and Anadarko Petroleum Corporation ("Anadarko"), announced an agreement to design and construct a new NGL pipeline (the "Texas Express Pipeline") that would originate in Skellytown, Texas and extend approximately 580 miles to NGL fractionation and storage facilities in Mont Belvieu, Texas. In addition, the joint venture would construct and own two new NGL gathering systems. The Texas Express Pipeline and related NGL gathering systems are expected to begin service in the second quarter of 2013.

§ In October 2011, we placed into service our fifth Mont Belvieu NGL fractionator, which has a nameplate capacity of 75 MBPD, and increased the total nameplate NGL fractionation capacity at our Mont Belvieu facility to 380 MBPD. In June 2011, we announced plans to construct a sixth NGL fractionator at our Mont Belvieu, Texas facility. The new fractionator will also have a nameplate capacity of 75 MBPD and accommodate NGLs from the continued growth of liquids-rich natural gas production from the Eagle Ford Shale and other producing areas. We have started construction of the new fractionator and we expect it to begin service in late 2012. Upon completion of the sixth NGL fractionator, we will have the capability to fractionate more than 450 MBPD of NGLs at our Mont Belvieu complex.

§ In May 2011, we announced plans to build an 80-mile extension (the second phase) of our South Texas Crude Oil Pipeline System, which would allow us to serve growing production areas in the southwestern portion of the Eagle Ford Shale supply basin. This extension is expected to be placed into service during the first quarter of 2013. The first phase of our South Texas Crude Oil Pipeline System expansion project comprises 140-miles of pipeline and is expected to begin service by the second quarter of 2012.

§ In May 2011, we announced plans to expand our Mont Belvieu polymer grade propylene ("PGP") fractionation facility to accommodate increased PGP demand. When completed, the expansion project will increase our net capacity to produce PGP by more than 10% from 73 MBPD (approximately 4.9 billion pounds per year) to 80.5 MBPD (approximately 5.4 billion pounds per year). The expansion is expected to be in service in the first quarter of 2013.

§ In March 2011, we announced an expansion of our primary Houston Ship Channel import/export terminal. This expansion project is expected to nearly double the terminal's fully refrigerated export loading capacity for propane and other NGLs to more than 10,000 barrels per hour, while enhancing the terminal's ability to load multiple vessels simultaneously. We expect to complete this expansion project in the second half of 2012.

§ In March 2011, we announced an expansion project involving the Rocky Mountain segment of our Mid-America Pipeline System. The Rocky Mountain pipeline expansion involves looping the existing system with approximately 218 miles of 16-inch diameter pipeline, as well as pump station modifications. This expansion project is expected to add 62.5 MBPD of transportation capacity to the Rocky Mountain pipeline's existing capacity of approximately 275 MBPD (after taking into account shipper commitments announced in January 2012). This expansion project is expected to begin service in the third quarter of 2014.

For additional information regarding these significant growth capital projects and other recent developments, see "Significant Recent Developments" under Item 7 of this annual report.

For the year ended December 31, 2011, we spent $3.55 billion on growth capital projects, of which approximately $867 million was for the Haynesville Extension and $1.59 billion for Eagle Ford Shale projects. Based on information currently available, we estimate our consolidated capital spending for 2012 will approximate $3.8 billion, which includes estimated expenditures of $3.5 billion for growth capital projects and $315 million for sustaining capital expenditures. For additional information regarding our capital spending program, see "Liquidity and Capital Resources—Capital Spending" under Item 7 of this annual report.

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Business Segment Discussion

Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the U.S., Canada and the Gulf of Mexico with domestic consumers and international markets. We have six reportable business segments: NGL Pipelines & Services; Onshore Natural Gas Pipelines & Services; Onshore Crude Oil Pipelines & Services; Offshore Pipelines & Services; Petrochemical & Refined Products Services; and Other Investments.

Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

The following sections present an overview of our business segments, including information regarding the principal products produced, services rendered, properties owned, seasonality and competition. Our results of operations and financial condition are subject to a variety of risks. For information regarding our risk factors, see Item 1A of this annual report.

Our business activities are subject to various federal, state and local laws and regulations governing a wide variety of topics, including commercial, operational, environmental, safety and other matters. For a discussion of the principal effects such laws and regulations have on our business, see "—Regulation" and "—Environmental and Safety Matters included within this Item 1 and 2.

Our consolidated revenues are derived from a wide customer base. Our largest non-affiliated customer for 2011, 2010 and 2009 was Shell Oil Company and its affiliates, which accounted for 10.6%, 9.4% and 9.8% of our consolidated revenues, respectively.

For information regarding our results of operations, including significant measures of historical throughput, production and processing volumes, see Item 7 of this annual report. In addition, certain of our operations entail the use of derivative instruments. For information regarding our use of commodity derivative instruments, see Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Financial Information by Business Segment

For detailed financial information regarding our business segments, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. Such financial information is incorporated by reference into this Item 1 and 2 discussion.

NGL Pipelines & Services

Our NGL Pipelines & Services business segment includes our: (i) natural gas processing business and related NGL marketing activities; (ii) NGL pipelines aggregating approximately 16,650 miles; (iii) NGL and related product terminal and storage facilities with approximately 156 MMBbls of net usable storage capacity; and (iv) 13 NGL fractionators. This segment also includes our import and export terminal operations.

NGL products (ethane, propane, normal butane, isobutane and natural gasoline) are used as raw materials by the petrochemical industry, as feedstocks by refiners in the production of motor gasoline and by industrial and residential users as fuel. Ethane is primarily used in the petrochemical industry as a feedstock for ethylene production, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used both as a petrochemical feedstock in the production of ethylene and propylene and as a heating, engine and industrial fuel. Normal butane is used as a petrochemical feedstock in the production of ethylene and butadiene (a key ingredient of synthetic rubber), as a blendstock for motor gasoline and to produce isobutane through isomerization. Isobutane is fractionated from mixed butane (a mixed stream of normal butane and isobutane) or produced from normal butane through the process of isomerization, and is used in refinery alkylation to enhance the octane content of motor gasoline, in the production of isooctane and other octane additives and in the production of propylene oxide. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is primarily used as a blendstock for motor gasoline or as a petrochemical feedstock.

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Natural gas processing and related NGL marketing activities. At the core of our natural gas processing business are 24 processing plants located across Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. Natural gas produced at the wellhead (especially in association with crude oil) contains varying amounts of NGLs. This liquids-rich natural gas in its raw form is usually not acceptable for transportation in the nation's natural gas pipeline systems or for commercial use as a fuel. Natural gas processing plants remove NGLs from the natural gas stream, which enables the natural gas to meet pipeline and commercial quality specifications. In addition, on an energy equivalent basis, NGLs generally have a greater economic value as a raw material for petrochemical and motor gasoline production than their value as components of a natural gas stream. After extraction by the processing plants, we typically transport the mixed NGLs to a centralized facility for fractionation into purity NGL products such as ethane, propane, normal butane, isobutane and natural gasoline. The purity NGL products can then be used in our NGL marketing activities to meet contractual requirements or sold on spot and forward markets. Also, we purchase natural gas from producers in connection with our natural gas processing activities. Once processed, this natural gas is available for sale through our natural gas marketing activities.

When operating and extraction costs of natural gas processing plants are higher than the incremental value of the NGL products that would be extracted, the recovery levels of certain NGL products, principally ethane, may be reduced or eliminated. This leads to a reduction in NGL volumes available for transportation and fractionation.

In our natural gas processing business, we enter into fee-based contracts, keepwhole and margin-band contracts, percent-of-liquids contracts, percent-of-proceeds contracts, and hybrid contracts (i.e., a combination of percent-of-liquids and fee-based contract terms). If a cash fee for natural gas processing services is stipulated by the contract, we record revenue when the natural gas has been processed and delivered to the producer. Under keepwhole and margin-band contracts, we take ownership of mixed NGLs extracted from the producer's natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to customers under NGL marketing sales contracts. Revenue under our percent-of-liquids contracts is recognized the same way, except that the volume of NGLs we take ownership of is less than the total amount of NGLs extracted from the producers' natural gas. Under a percent-of-liquids contract, the producer retains title to a percentage of the mixed NGLs we extract and generally bears the cost of natural gas associated with shrinkage and plant fuel. The value of natural gas lost as a result of NGL extraction (i.e., shrinkage) and consumed as plant fuel is referred to as plant thermal reduction ("PTR"). Under a percent-of-proceeds contract, we share in the proceeds generated from the sale of the mixed NGLs we extract on the producer's behalf. The NGL volumes we earn and take title to in connection with our processing activities are referred to as our equity NGL production.

In general, our percent-of-liquids, hybrid and keepwhole contracts give us the right (but not the obligation) to process natural gas for a producer; thus, we are protected from processing natural gas at an economic loss during times when the sum of our costs exceeds the value of the mixed NGLs in which we would take ownership. Generally, our natural gas processing agreements have terms ranging from month-to-month to life of the producing lease. Intermediate terms of one to ten years are also common.

To the extent that we are obligated under our keepwhole and margin-band contracts to compensate the producer for the natural gas equivalent energy value of mixed NGLs we extract from the natural gas stream, we are exposed to various risks, primarily commodity price fluctuations. However, our margin band contracts typically contain terms which limit our exposure to such risks. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply and demand and a variety of additional factors that are beyond our control. Periodically, we attempt to mitigate these risks through the use of commodity derivative instruments (e.g., fixed-price natural gas purchases and NGL sales contracts).

Our NGL marketing activities generate revenues from the sale and delivery of NGLs we take title to through our natural gas processing activities (i.e., our equity NGL production) and open market and contract purchases from third parties. Our NGL marketing sales contracts may also include forward product sales contracts. In general, sales prices referenced in the contracts utilized within our NGL marketing activities are market-based and may include pricing differentials for such factors as delivery location. The majority of our consolidated revenues and costs and expenses are generated from marketing activities, including those associated with NGLs. Changes in our consolidated revenues and operating costs and expenses period-to-period are explained in part by changes in market prices for the products we sell. The results of operations from our NGL marketing activities are generally dependent upon the volume of products sold and the sales prices charged to customers. The volume of products sold may fluctuate from period-to-period depending on market conditions, volumes produced and opportunities, which may be influenced by current and forward market prices for purity NGL products and our hedging activities.

For additional information regarding our inventories and consolidated segment revenues and expenses, see Notes 7 and 14, respectively, of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

NGL pipelines, storage and terminal facilities and import/export operations. Our NGL pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities, refineries and import terminals to fractionation plants and storage facilities; distribute and collect purity NGL products to and from fractionation plants, storage and terminal facilities, petrochemical plants, export facilities and refineries; and deliver propane to customers along the Dixie Pipeline and certain sections of the Mid-America Pipeline System. Revenues from our NGL pipeline transportation agreements are generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Accordingly, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers (including those charged internally, which are eliminated in the preparation of our Consolidated Financial Statements). Certain of our NGL pipelines offer firm capacity reservation services whereby the shipper pays a contractually stated fee based on the level of throughput capacity reserved in our pipelines whether or not the shipper actually utilizes such capacity. Fees charged for NGL transportation services are either contractual or regulated by governmental agencies, including the Federal Energy Regulatory Commission ("FERC"). Excluding inventories held in connection with our marketing activities, we typically do not take title to the products transported by our NGL pipelines; rather, the shipper retains title and the associated commodity price risk. However, we occasionally act as shipper for certain volumes being transported.

Our NGL and related product storage facilities are integral parts of our operations used for the storage of products owned by us and our customers. In general, our underground salt dome storage caverns (or wells) are used to store mixed NGLs and purity NGL, petrochemical and refined products. We collect storage revenues under our NGL and related product storage contracts based on the number of days a customer has volumes in storage multiplied by a storage fee (as defined in each contract). With respect to capacity reservation agreements, we collect a fee for reserving storage capacity for certain customers in our underground storage wells. Customers pay reservation fees based on the level of storage capacity reserved rather than the actual volumes stored. When a customer exceeds its reserved capacity, we charge those customers an excess storage fee. In addition, we generally charge customers throughput fees based on volumes delivered into and subsequently withdrawn from storage. Accordingly, the profitability of our storage operations is dependent upon the level of storage capacity reserved by customers, the volume of product delivered into and withdrawn from the underground caverns and the level of fees charged.

We operate NGL import and export facilities located on the Houston Ship Channel in southeast Texas and an NGL terminal in Providence, Rhode Island with ship unloading capabilities. In addition, we operate NGL terminal facilities in 22 states that are connected to our pipelines and/or support our NGL marketing activities. Our NGL import facility is primarily used to offload volumes for delivery to our storage and fractionation facilities located in Mont Belvieu, Texas. Our NGL export facility is used for loading refrigerated marine tankers for customers. Revenues from our terminal services are primarily based on fees per unit of volume loaded or unloaded and may also include demand payments if minimum volume commitments are not met or the terminaling contracts are cancelled. Accordingly, the profitability of our NGL terminal activities primarily depends on the available quantities of NGLs to be loaded and offloaded and the fees we charge for these services.

NGL fractionation. We own or have interests in 13 NGL fractionators located in Texas, Louisiana and Ohio. NGL fractionators separate mixed NGL streams into purity NGL products. The primary sources of mixed NGLs fractionated in the U.S. are domestic natural gas processing plants, crude oil refineries and imports of butane and propane mixtures. Mixed NGLs sourced from domestic natural gas processing plants and crude oil refineries are typically transported by NGL pipelines and, to a lesser extent, by railcar and truck to NGL fractionation facilities.

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Mixed NGLs extracted by domestic natural gas processing plants represent the largest source of volumes processed by our NGL fractionators. Based upon industry data, we believe that sufficient volumes of mixed NGLs, especially those originating from Gulf Coast, Rocky Mountain and Midcontinent natural gas processing plants, will be available for fractionation in commercially viable quantities for the foreseeable future. Significant volumes of mixed NGLs are contractually committed to be processed at our NGL fractionators by joint owners and third party customers.

Our NGL fractionation facilities process mixed NGL streams for third party customers and support our NGL marketing activities. We typically earn revenues from NGL fractionation under fee-based arrangements, including a significant level of demand-based fees. These fees (usually stated in cents per gallon) are contractually subject to adjustment for changes in certain fractionation expenses (e.g., natural gas fuel costs). At our Norco facility in Louisiana, we perform fractionation services for certain customers under percent-of-liquids contracts. The results of operations of our NGL fractionation business are generally dependent upon the volume of mixed NGLs fractionated and either the level of fractionation fees charged (under fee-based contracts) or the value of NGLs received (under percent-of-liquids arrangements). Our fee-based fractionation customers retain title to the NGLs that we process for them. To the extent we fractionate volumes for customers under percent-of-liquids contracts, we are exposed to fluctuations in NGL prices (i.e., commodity price risk). Periodically, we attempt to mitigate these risks through the use of commodity derivative instruments such as forward sales contracts.

Seasonality. Our natural gas processing and NGL fractionation operations typically exhibit little to no seasonal variation. Our NGL marketing activities rely on inventories of purity NGL products. Propane and normal butane inventories are typically at higher levels from March through November since these products are normally in higher demand and at higher price levels during the winter months. Ethane, isobutane and natural gasoline inventories are generally stable and less cyclical throughout the year.

NGL pipeline transportation volumes are generally higher from October through March due to higher demand for propane (for residential heating) and normal butane (for blending into motor gasoline). With respect to our NGL and related product storage facilities, we usually experience an increase in demand for storage services during the spring and summer months due to increased feedstock storage requirements for motor gasoline production and a decrease during the fall and winter months when propane inventories are being drawn down for heating needs. Likewise, the revenues we recognize from NGL marketing activities are predicated on the overall demand for such products, which may fluctuate due to seasonal needs for gasoline blending feedstocks, heating requirements and similar factors. In general, our import volumes peak during the spring and summer months and our export volumes are typically at their highest levels during the winter months. Lastly, our facilities located along the Gulf Coast of the U.S. may be affected by weather events such as hurricanes and tropical storms, which generally arise during the summer and fall months.

Competition. Within their respective market areas, our natural gas processing business activities and related NGL marketing activities encounter competition from fully integrated oil companies, intrastate pipeline companies, major interstate pipeline companies and their non-regulated affiliates, financial institutions with trading platforms and independent processors. Each of our marketing competitors has varying levels of financial and personnel resources, and competition generally revolves around price, quality of customer service and proximity to customers and other market hubs. In the markets served by our NGL pipelines, we compete with a number of intrastate and interstate pipeline companies (including those affiliated with major oil, petrochemical and natural gas companies) and barge, rail and truck fleet operations. In general, our NGL pipelines compete with these entities in terms of transportation fees and quality of customer service.

Our primary competitors in the NGL and related product storage businesses are integrated major oil companies, chemical companies and other storage and pipeline companies. We compete with other storage service providers primarily in terms of the fees charged, number of pipeline connections provided and operational dependability. Our import and export operations compete with those operated by major oil and chemical companies primarily in terms of loading and offloading throughput capacity.

We compete with a number of NGL fractionators in Texas, Louisiana, New Mexico and Kansas. Competition for such services is primarily based on the fractionation fee charged. However, the ability of an NGL

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fractionator to receive a customer's mixed NGLs and store and distribute its purity NGL products is also an important competitive factor and is a function of having the necessary pipeline and storage infrastructure.

Properties. The following table summarizes the 24 natural gas processing facilities included in our NGL Pipelines & Services business segment at February 1, 2012:

Description of Asset	Location(s)	Our Ownership Interest		Net Gas Processing Capacity (Bcf/d) (1)	Total Gas Processing Capacity (Bcf/d)
Natural gas processing facilities:					
Meeker	Colorado	100.0%		1.70	1.70
Pioneer (two facilities)	Wyoming	100.0%		1.35	1.35
Toca	Louisiana	66.7%	(2)	0.70	1.10
Chaco	New Mexico	100.0%		0.65	0.65
Pascagoula	Mississippi	40.0%	(2)	0.60	1.50
North Terrebonne	Louisiana	56.2%	(2)	0.53	0.95
Neptune	Louisiana	66.0%	(2)	0.43	0.65
Thompsonville	Texas	100.0%		0.33	0.33
Shoup	Texas	100.0%		0.29	0.29
Gilmore	Texas	100.0%		0.25	0.25
Armstrong	Texas	100.0%		0.25	0.25
San Martin	Texas	100.0%		0.20	0.20
Sea Robin	Louisiana	15.5%	(2)	0.15	0.95
Delmita	Texas	100.0%		0.15	0.15
Yscloskey	Louisiana	11.1%	(2)	0.14	1.30
Carlsbad	New Mexico	100.0%		0.13	0.13
Sonora	Texas	100.0%		0.12	0.12
Indian Springs	Texas	75.0%	(2)	0.09	0.12
Shilling	Texas	100.0%		0.11	0.11
Venice	Louisiana	13.1%	(3)	0.10	0.75
Burns Point	Louisiana	50.0%	(2)	0.08	0.16
Indian Basin	New Mexico	42.4%	(2)	0.08	0.20
Chaparral	New Mexico	100.0%		0.04	0.04
Total processing capacities				8.47	13.25

(1) The approximate net gas processing capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as the level of volumes an owner processes at the facility and its ownership interest in the facility.
(2) We proportionately consolidate our undivided interest in these operating assets.
(3) Our ownership in the Venice plant is held indirectly through our equity method investment in Venice Energy Services Company, L.L.C. ("VESCO").

Our natural gas processing facilities can be characterized as two distinct types: (i) straddle plants situated on mainline natural gas pipelines owned either by us or by third parties or (ii) field plants that process natural gas from gathering pipelines. We operate the Meeker, Pioneer, Toca, Chaco, North Terrebonne, Neptune, Burns Point, Carlsbad and Chaparral plants and all of the Texas facilities. On a weighted-average basis, utilization rates for these assets were 56.1%, 51.2% and 48.3% during the years ended December 31, 2011, 2010 and 2009, respectively. These rates reflect the periods in which we owned an interest in such facilities.

Our NGL marketing activities utilize a fleet of approximately 500 railcars, the majority of which are leased from third parties. These railcars are used to deliver feedstocks to our facilities and to distribute NGLs throughout the U.S. and parts of Canada. We have rail loading and unloading capabilities at certain of our terminal facilities in Alabama, Arizona, California, Kansas, Louisiana, Minnesota, Mississippi, Nevada, New York, North Carolina and Texas. These facilities service both our rail shipments and those of our customers.

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The following table summarizes the significant NGL pipelines and related storage assets included in our NGL Pipelines & Services business segment at February 1, 2012:

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Net Usable Storage Capacity (MMBbls)
NGL pipelines:				
Mid-America Pipeline System	Midwest and Western U.S.	100.0%	7,923	
Seminole Pipeline	Texas	100.0% (1)	1,373	
South Texas NGL System	Texas	100.0%	1,411	
Dixie Pipeline	South and Southeastern U.S.	100.0%	1,306	
Chaparral NGL System	Texas, New Mexico	100.0%	1,011	
Louisiana Pipeline System	Louisiana	100.0%	955	
Skelly-Belvieu Pipeline	Texas	50.0% (2)	572	
Promix NGL Gathering System	Louisiana	50.0% (3)	365	
Houston Ship Channel	Texas	100.0%	300	
Rio Grande Pipeline	Texas	70.0% (4)	249	
Panola Pipeline	Texas	100.0%	223	
Lou-Tex NGL Pipeline	Texas, Louisiana	100.0%	206	
South Dean Pipeline	Texas	100.0%	186	
Tri-States NGL Pipeline	Alabama, Mississippi, Louisiana	83.3% (5)	167	
Chunchula Pipeline	Alabama, Mississippi	100.0%	144	
Others (five systems) (6)	Various	Various (7)	257	
Total miles			16,648	
NGL and related product storage capacity by state:				
Texas (8)				120.0
Louisiana				12.9
Kansas				8.6
Mississippi				5.1
Others (9)				9.2
Total net usable storage capacity (10)				155.8

(1) In December 2011, we acquired the remaining 10% ownership interest in Seminole Pipeline Company ("Seminole").

(2) Our ownership interest in the Skelly-Belvieu Pipeline is held indirectly through our equity method investment in Skelly-Belvieu Pipeline Company, L.L.C. ("Skelly-Belvieu").

(3) Our ownership interest in the Promix NGL Gathering System is held indirectly through our equity method investment in K/D/S Promix, L.L.C. ("Promix").

(4) We own a 70% consolidated interest in the Rio Grande Pipeline through our majority owned subsidiary, Rio Grande Pipeline Company.

(5) We own an 83.3% consolidated interest in the Tri-States NGL Pipeline through our majority owned subsidiary, Tri-States NGL Pipeline, L.L.C.

(6) Includes our Belle Rose and Wilprise pipelines located in the coastal regions of Louisiana and Mississippi; Port Arthur pipelines located in southeast Texas; and our Meeker pipeline in Colorado.
(7) We own a 74.7% consolidated interest in the 30-mile Wilprise pipeline through our majority owned subsidiary, Wilprise Pipeline Company, LLC. We proportionately consolidate our 50% undivided interest in a 45-mile segment of the Port Arthur pipelines. The remainder of these NGL pipelines are wholly owned.
(8) The amount shown for Texas includes 34 underground NGL, petrochemical and refined products storage caverns with an aggregate working capacity of approximately 100 MMBbls. These 34 caverns are located in Mont Belvieu, Texas.
(9) Includes storage capacity at our facilities in Alabama, Arizona, California, Georgia, Illinois, Indiana, Iowa, Minnesota, Missouri, Nebraska, Nevada, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina and Wisconsin.
(10) Our underground storage caverns and above ground storage tanks have an aggregate 155.8 MMBbls of net usable storage capacity. Our aggregate net usable storage capacity includes 21.3 MMBbls held under long-term operating leases at facilities located in Indiana, Kansas, Louisiana and Texas. Approximately 2 MMBbls of our net usable storage capacity in Louisiana is held indirectly through our equity method investments in Promix and Baton Rouge Fractionators LLC (“BRF”). The remainder of our NGL underground storage caverns and above ground storage tanks are wholly owned.

The maximum number of barrels that our NGL pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products being shipped and demand levels at various delivery points, the exact capacities of our NGL pipelines cannot be reliably determined. We measure the utilization rates of such pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 2,180 MBPD, 2,207 MBPD and 2,099 MBPD during the years ended December 31, 2011, 2010 and 2009, respectively.

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The following information highlights the general use of each of our principal NGL pipelines. We operate our NGL pipelines with the exception of the Tri-States pipeline.

§ The Mid-America Pipeline System is a regulated NGL pipeline system consisting of four primary segments: the 2,932-mile Rocky Mountain pipeline, the 2,148-mile Conway North pipeline, the 621-mile Ethane-Propane Mix pipeline and the 2,222-mile Conway South pipeline. The Mid-America Pipeline System is present in 13 states: Colorado, Illinois, Iowa, Kansas, Minnesota, Missouri, Nebraska, New Mexico, Oklahoma, Texas, Utah, Wisconsin and Wyoming. The Rocky Mountain pipeline transports mixed NGLs from the Rocky Mountain Overthrust and San Juan Basin areas to the Hobbs hub located on the Texas-New Mexico border. The Conway North segment links the NGL hub at Conway, Kansas to refineries, petrochemical plants and propane markets in the upper Midwest. In addition, the Conway North segment has access to NGL supplies from Canada's Western Sedimentary Basin through third party connections. Effective January 1, 2011, a separate tariff was filed for the Ethane-Propane Mix segment, which was formerly treated as part of the Conway North segment. The Ethane-Propane Mix segment transports ethane/propane mix primarily to petrochemical plants in Illinois from the NGL hub at Conway and other origin points in Illinois and Iowa. The Conway South pipeline connects the Conway hub with Kansas refineries and provides bi-directional transportation of NGLs between Conway, Kansas and the Hobbs hub. The Mid-America Pipeline System interconnects with our Seminole Pipeline and Hobbs NGL fractionation and storage facility at the Hobbs hub. This system includes 14 unregulated propane terminals.

During 2011, approximately 52% of the volumes transported on the Mid-America Pipeline System were mixed NGLs originating from natural gas processing plants. The remaining volumes consisted of purity NGL products originating from NGL fractionators located in Kansas, Oklahoma and Texas, as well as deliveries from Canada.

In March 2011, we announced an expansion project involving the Rocky Mountain segment of our Mid-America Pipeline System. The Rocky Mountain pipeline expansion involves looping the existing system with approximately 218 miles of 16-inch diameter pipeline, as well as pump station modifications. This expansion project is expected to add 62.5 MBPD of transportation capacity to the Rocky Mountain pipeline's existing capacity of approximately 275 MBPD (after taking into account shipper commitments announced in January 2012). This expansion project is expected to begin service in the third quarter of 2014. For additional information regarding this growth capital project, see "Significant Recent Developments—Expansion of Our Mid-America Pipeline System in the Rocky Mountains" under Item 7 of this annual report.

§ The Seminole Pipeline is a regulated pipeline that transports NGLs from the Hobbs hub and the Permian Basin area of West Texas to markets in southeast Texas including our NGL fractionation facility in Mont Belvieu, Texas. NGLs originating on the Mid-America Pipeline System are the primary source of throughput for the Seminole Pipeline.

§ The South Texas NGL System is a network of NGL gathering and transportation pipelines located in South Texas. The system gathers and transports mixed NGLs from our South Texas natural gas processing plants to our South Texas NGL fractionators. In turn, the system transports purity NGL products from our South Texas NGL fractionators to refineries and petrochemical plants located between Corpus Christi, Texas and Houston, Texas and within the Texas City-Houston area, as well as to interconnects with common carrier NGL pipelines. The South Texas NGL System also connects our South Texas NGL fractionators with our storage facility in Mont Belvieu, Texas.

§ The Dixie Pipeline is a regulated pipeline that extends from southeast Texas and Louisiana to markets in the southeastern U.S. and transports propane and other NGLs. Propane supplies transported on this system primarily originate from southeast Texas, south Louisiana and Mississippi. This system includes eight unregulated propane terminals and operates in seven states: Texas, Louisiana, Mississippi, Alabama, Georgia, South Carolina and North

Carolina.

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§ The Chaparral NGL System transports NGLs from natural gas processing plants in West Texas and New Mexico to Mont Belvieu, Texas. This system consists of the 831-mile regulated Chaparral pipeline and the 180-mile unregulated Quanah pipeline.

§ The Louisiana Pipeline System is a network of NGL pipelines located in southern Louisiana. This system transports NGLs originating in Louisiana and Texas to refineries and petrochemical plants located along the Mississippi River corridor in southern Louisiana. This system also provides transportation services for our natural gas processing plants, NGL fractionators and other assets located in Louisiana. Originating from a central point in Henry, Louisiana, pipelines extend westward to Lake Charles, Louisiana, northward to an interconnect with the Dixie Pipeline at Breaux Bridge, Louisiana and eastward in Louisiana, where our Promix, Norco and Tebone NGL fractionation and Sorrento storage facilities are located.

§ The Skelly-Belvieu Pipeline is a regulated pipeline that transports mixed NGLs from Skellytown, Texas to Mont Belvieu, Texas. The Skelly-Belvieu Pipeline receives NGLs through a pipeline interconnect with our Mid-America Pipeline System in Skellytown, Texas. We became operator of this pipeline in January 2011.

§ The Promix NGL Gathering System gathers mixed NGLs from natural gas processing plants in southern Louisiana for delivery to our Promix NGL fractionator.

§ The Houston Ship Channel pipeline system connects our Mont Belvieu, Texas facilities with our Houston Ship Channel import/export terminals and various third party petrochemical plants, refineries and other pipelines located along the Houston Ship Channel.

§ The Rio Grande Pipeline is a regulated pipeline originating near Odessa, Texas that transports mixed NGLs to a pipeline interconnect at the Mexican border south of El Paso, Texas.

§ The Lou-Tex NGL Pipeline system transports NGLs and refinery grade propylene between the Louisiana and Texas markets.

In January 2012, we announced the receipt of sufficient transportation commitments to support development of our 1,230-mile ATEX Express that will transport growing ethane production from the Marcellus and Utica Shale producing areas of Pennsylvania, West Virginia and Ohio to the U.S. Gulf Coast. We expect that the ATEX Express will begin commercial operations in the first quarter of 2014. For additional information regarding this growth capital project, see “Significant Recent Developments—Development of Our ATEX Express Long-Haul Ethane Pipeline” under Item 7 of this annual report.

Our NGL and related product storage and terminal facilities are integral components of our midstream energy infrastructure. We operate these storage and terminal facilities, with the exception of certain Louisiana storage locations, the leased Markham facility in Texas and a leased facility in Kansas that are operated for us by third parties.

Our largest underground storage facility is located in Mont Belvieu, Texas. This storage facility consists of 34 underground NGL, petrochemical and refined products salt dome storage caverns with an aggregate usable storage capacity of approximately 100 MMBbls, a brine system with approximately 20 MMBbls of above-ground brine storage pit capacity and two brine production wells. These assets store and deliver NGLs (such as ethane and propane) and certain petrochemical products for industrial customers located along the upper Texas Gulf Coast.

In February 2011, we experienced an NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. West Storage consists of ten underground salt dome storage caverns with a storage capacity of approximately 15 MMBbls. Through the reconfiguration of product receipt and delivery capabilities and other measures, we readily returned our Mont Belvieu plants and related assets to close to the same capabilities as we had prior to the incident; however, our West Storage location and associated underground storage wells remain partially inoperative at this time. Remaining repairs to this location are underway and are expected to be completed in stages by mid-2012.

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The following table summarizes the 13 NGL fractionators included in our NGL Pipelines & Services business segment at February 1, 2012:

Description of Asset	Location	Our Ownership Interest	Net Plant Capacity (MBPD) (1)	Total Plant Capacity (MBPD)
NGL fractionation facilities:				
Mont Belvieu (five units) (2)	Texas	Various (3)	328	380
Shoup and Armstrong	Texas	100.0%	98	98
Hobbs	Texas	100.0%	75	75
Norco	Louisiana	100.0%	75	75
Promix	Louisiana	50.0% (4)	70	140
BRF	Louisiana	32.2% (5)	19	60
Tebone	Louisiana	56.4% (6)	17	30
Todhunter	Ohio	100.0%	3	3
Total plant fractionation capacities			685	861

(1) The approximate net plant capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as the level of volumes an owner processes at the facility and its ownership interest in the facility.
(2) There are five NGL fractionators located at our Mont Belvieu, Texas facility. Our fifth NGL fractionator commenced commercial operations at this facility in October 2011.
(3) We proportionately consolidate our 75% undivided interest in four of the NGL fractionators located at our Mont Belvieu, Texas facility. The fifth NGL fractionator at this facility is wholly owned.
(4) Our ownership interest in the Promix fractionator is held indirectly through our equity method investment in Promix.
(5) Our ownership interest in the BRF fractionator is held indirectly through our equity method investment in BRF.
(6) We proportionately consolidate our undivided interest in the Tebone fractionator.

In March 2011, we sold two small NGL fractionation facilities located in northeast Colorado for approximately $30.0 million in cash. These assets were not integrated with our other midstream energy assets.

The following information highlights the general use of each of our principal NGL fractionators. We operate all of our NGL fractionators.

§ Our Mont Belvieu NGL fractionation facility is located in Mont Belvieu, Texas, which is a key hub of the NGL industry. This facility fractionates mixed NGLs from several major NGL supply basins in North America, including the Mid-Continent, Permian Basin, San Juan Basin, Rocky Mountains, East Texas and the Gulf Coast.

In June 2011, we announced plans to construct a sixth NGL fractionator at our Mont Belvieu, Texas facility. The new fractionation facility will have a nameplate capacity of 75 MBPD and accommodate continued growth of liquids-rich natural gas production from the Eagle Ford Shale and other producing areas. We have obtained all necessary approvals and permits and have started construction of the new facility, which is projected to begin service in late 2012. Upon completion of the sixth NGL fractionator, we expect to have the capability to fractionate more than 450 MBPD of NGLs at our Mont Belvieu complex.

§ Our Shoup and Armstrong fractionators process mixed NGLs supplied by our South Texas natural gas processing plants. Purity NGL products from the Shoup and Armstrong fractionators are transported to local markets in the Corpus Christi area and also to Mont Belvieu, Texas using our South Texas NGL System.

§ Our Hobbs NGL fractionator is located in Gaines County, Texas, where it serves petrochemical plants and refineries in West Texas, New Mexico, California and northern Mexico. The Hobbs fractionator receives mixed NGLs from several major supply basins, including Mid-Continent, Permian Basin, San Juan Basin and the Rocky Mountains. The facility is located at the interconnect of our Mid-America Pipeline System and Seminole Pipeline, thus providing us the flexibility to supply the nation's largest NGL hub at Mont Belvieu, Texas as well as access to the second-largest NGL hub at Conway, Kansas.

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§ Our Norco NGL fractionator receives mixed NGLs via pipeline from refineries and natural gas processing plants located in southern Louisiana and along the Mississippi and Alabama Gulf Coast, including from our Yscloskey, Pascagoula, Venice and Toca facilities.

§ The Promix NGL fractionator receives mixed NGLs via pipeline from natural gas processing plants located in southern Louisiana and along the Mississippi Gulf Coast, including from our Neptune, Burns Point and Pascagoula facilities. In addition to the Promix NGL Gathering System (described previously), Promix owns three NGL storage caverns and a barge loading facility that are integral to its operations. Promix leases a fourth NGL storage cavern.

§ The BRF fractionator receives mixed NGLs from natural gas processing plants located in Alabama, Mississippi and southern Louisiana.

On a weighted-average basis, utilization rates for our NGL fractionators were 90.2%, 90.7% and 88.8% during the years ended December 31, 2011, 2010 and 2009, respectively. These rates reflect the periods in which we owned an interest in such facilities or, for recently constructed facilities, since the dates such assets were placed into service.

Our NGL operations include import and export facilities located on the Houston Ship Channel in southeast Texas. We own an import and export facility located on land we lease from Oiltanking Houston LP. Our import facility can offload NGLs from tanker vessels at rates up to 14,000 barrels per hour depending on the product. Our export facility can load cargoes of refrigerated propane and butane onto tanker vessels at rates up to 6,700 barrels per hour. In addition to these facilities, we own a barge dock also located on the Houston Ship Channel that can load or offload two barges of NGLs or refinery-grade propylene simultaneously at rates up to 5,000 barrels per hour. We also own an NGL terminal in Providence, Rhode Island that includes 0.4 MMBbls of refrigerated tank storage capacity and ship unloading capabilities at rates of up to 11,800 barrels per hour. Our average combined NGL import and export volumes were 103 MBPD, 114 MBPD and 98 MBPD for the years ended December 31, 2011, 2010 and 2009, respectively.

In March 2011, we announced an expansion of our primary Houston Ship Channel import/export terminal. This expansion project is expected to nearly double the terminal’s fully refrigerated export loading capacity for propane and other NGLs to more than 10,000 barrels per hour, while also enhancing the terminal’s ability to load multiple vessels simultaneously. We expect to complete this project in the second half of 2012.

Onshore Natural Gas Pipelines & Services

Our Onshore Natural Gas Pipelines & Services business segment includes approximately 20,200 miles of onshore natural gas pipeline systems that provide for the gathering and transportation of natural gas in Colorado, Louisiana, New Mexico, Texas and Wyoming. We lease salt dome natural gas storage facilities located in Texas and Louisiana and own a salt dome storage cavern in Texas that are integral to our pipeline operations. This segment also includes our related natural gas marketing activities.

Onshore natural gas pipelines and related natural gas storage and marketing activities. Our onshore natural gas pipeline systems and storage facilities provide for the gathering and transportation of natural gas from major producing regions such as the San Juan, Barnett Shale, Permian, Piceance, Greater Green River, Haynesville Shale and Eagle Ford Shale supply basins in the western U.S. In addition, certain of these systems receive natural gas production from the Gulf of Mexico through coastal pipeline interconnects with offshore pipelines. Our onshore natural gas pipelines receive natural gas from producers, other pipelines or shippers at the wellhead or through system interconnects and redeliver the natural gas to processing facilities, local gas distribution companies, industrial or municipal customers, storage facilities or to other onshore pipelines.

Our onshore natural gas pipelines typically generate revenues from transportation agreements under which shippers are billed a fee per unit of volume transported (typically per MMBtu) multiplied by the volume gathered or delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Certain of our onshore natural gas pipelines offer firm capacity reservation services whereby the shipper pays a contractually stated fee based on the level of throughput capacity

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reserved in our pipelines whether or not the shipper actually utilizes such capacity. Under our natural gas storage contracts, there are typically two components of revenues: (i) monthly demand payments, which are associated with a customer's storage capacity reservation and paid regardless of actual usage, and (ii) storage fees per unit of volume stored at our facilities. In connection with our natural gas transportation services and marketing activities, intrastate natural gas pipelines (such as our Acadian Gas System) may also purchase natural gas from producers and other suppliers for transport and resale to customers such as electric utility companies, local natural gas distribution companies, industrial users and other natural gas marketing companies.

Our natural gas marketing activities generate revenues from the sale and delivery of natural gas obtained from third party well-head purchases, regional natural gas processing plants and the open market. In general, sales prices referenced in the contracts utilized within our natural gas marketing activities are market-based and may include pricing differentials for such factors as delivery location. The results of operations for our onshore natural gas pipelines and related storage and marketing activities are generally dependent upon the volume of natural gas transported, stored and/or sold, the level of firm capacity reservations made by customers and amounts charged to customers (including those charged internally, which are eliminated in the preparation of our Consolidated Financial Statements).

We are exposed to commodity price risk to the extent that we take title to natural gas volumes in connection with certain intrastate natural gas transportation contracts and our natural gas marketing activities. In addition, we purchase and resell natural gas for certain producers that use our San Juan, Carlsbad and Jonah Gathering Systems and certain segments of our Texas Intrastate System. Also, several of our gathering systems, while not providing marketing services, have some exposure to risks related to fluctuations in commodity prices through transportation arrangements with shippers. For example, nearly all of the transportation revenues generated by our San Juan Gathering System are based on a percentage of a regional price index for natural gas. This index is subject to change based on a variety of factors including natural gas supply and consumer demand. We use derivative instruments to mitigate our exposure to commodity price risks associated with our natural gas pipelines and services business.

Seasonality. Typically, our onshore natural gas pipelines experience higher throughput rates during the summer months as natural gas-fired power generation utilities increase their output to meet residential and commercial demand for electricity used for air conditioning. Higher throughput rates are also experienced in the winter months as natural gas is used to meet residential and commercial heating requirements. Our facilities located along the Gulf Coast of the U.S. may be affected by weather events such as hurricanes and tropical storms, which generally arise during the summer and fall months.

Competition. Within their market areas, our onshore natural gas pipelines compete with other natural gas pipelines on the basis of price (in terms of transportation fees), quality of customer service and operational flexibility. Our natural gas marketing activities compete primarily with other natural gas pipeline companies and their marketing affiliates and financial institutions with trading platforms. Competition in the natural gas marketing business is based primarily on quality of customer service, competitive pricing and proximity to customers and market hubs.

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Properties. The following table summarizes the significant assets included in our Onshore Natural Gas Pipelines & Services business segment at February 1, 2012:

Description of Asset	Location(s)	Our Ownership Interest		Length (Miles)	Approx. Net Capacity Pipelines (MMcf/d)	Approx. Net Capacity Usable Storage (Bcf)
Onshore natural gas pipelines and related storage facilities:						
Texas Intrastate System	Texas	Various	(1)	8,411	6,640	13.0
Acadian Gas System	Louisiana	Various	(2)	1,329	2,949	1.3
Jonah Gathering System	Wyoming	100.0%		925	2,550	--
San Juan Gathering System (3)	New Mexico, Colorado	100.0%		6,558	1,750	--
Piceance Basin Gathering System	Colorado	100.0%		190	1,600	--
White River Hub	Colorado	50.0%	(4)	10	1,500	--
Haynesville Gathering Systems (5)	Louisiana, Texas	100.0%		295	1,300	--
Fairplay Gathering System (6)	Texas	100.0%		250	285	--
Carlsbad Gathering System	Texas, New Mexico	100.0%		953	220	--
Indian Springs Gathering System	Texas	80.0%	(7)	197	160	--
Delmita Gathering System	Texas	100.0%		241	145	--
South Texas Gathering System	Texas	100.0%		589	143	--
Big Thicket Gathering System	Texas	100.0%		253	60	--
Total				20,201		14.3

(1) Of the 8,411 miles comprising the Texas Intrastate System, we lease 265 miles and proportionately consolidate our 50% undivided interest in another 634 miles. Our Wilson natural gas storage facility consists of five underground salt dome natural gas storage caverns with 13.0 Bcf of usable storage capacity, four of which (comprising 6.9 Bcf of usable capacity) are held under an operating lease that expires in January 2028. The remainder of our Texas Intrastate System is wholly owned.

(2) The Acadian Gas System is wholly owned except for the 27-mile Evangeline pipeline and a 1.3 Bcf storage facility we hold under an operating lease that expires in December 2012. Our ownership interest in the Evangeline pipeline is held indirectly through our aggregate 49.5% equity method investment in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp (collectively "Evangeline").

(3) In 2011, we completed the integration of the Val Verde Gas Gathering System we acquired in the TEPPCO Merger into our legacy San Juan Gathering System. The combined natural gas gathering system retained the San Juan Gathering System name.

(4) Our ownership interest in the White River Hub facility is held indirectly through our equity method investment in White River Hub, LLC ("White River Hub").

(5) Our Haynesville Gathering Systems consist of the State Line gathering system that we acquired in May 2010 and the South East Mansfield gathering system and South East Stanley gathering system that we constructed and placed into service during 2010 and 2011, respectively.

(6) We acquired the Fairplay Gathering System in May 2010.

(7) We proportionately consolidate our undivided interest in the Indian Springs Gathering System.

In December 2011, we sold our natural gas storage facilities in Petal and Hattiesburg, Mississippi that were owned by Crystal Holding L.L.C. ("Crystal") for $550.0 million in cash, before working capital adjustments. For more information regarding the sale of our Mississippi natural gas storage facilities, see "Significant Recent Developments—Sale of Our Mississippi Natural Gas Storage Facilities" included under Item 7 of this annual report. In August 2011, we sold our Alabama Intrastate System for $21.8 million in cash, before working capital adjustments. The Alabama system was not integrated with our other midstream energy assets.

On a weighted-average basis, aggregate utilization rates for our onshore natural gas pipelines were approximately 64.6%, 64.2% and 64.4% during the years ended December 31, 2011, 2010 and 2009, respectively. Such utilization rates represent actual natural gas volumes delivered as a percentage of our nominal delivery capacity and do not reflect firm capacity reservation agreements where throughput capacity is reserved whether or not the shipper actually utilizes such capacity. Our utilization rates reflect the periods in which we owned an interest in such assets or, for recently constructed assets, since the dates such assets were placed into service.

The following information highlights the general use of each of our principal onshore natural gas pipelines. With the exception of the White River Hub and certain minor segments of the Texas Intrastate System, we operate our onshore natural gas pipelines and storage facilities.

§ The Texas Intrastate System gathers, transports and stores natural gas from supply basins in Texas (from both onshore and offshore sources) for redelivery to local gas distribution companies and electric generation and industrial and municipal consumers as well as to connections with intrastate and interstate pipelines. The Texas Intrastate System is comprised of the 6,917-mile Enterprise Texas pipeline system, the 634-mile Channel pipeline system, the 708-mile Waha gathering system and the 152-mile TPC Offshore gathering system. The Enterprise Texas pipeline system includes a 265-mile pipeline we lease from an affiliate of Energy Transfer Equity, L.P. ("Energy Transfer Equity"). The Wilson natural gas storage facility located in Wharton County, Texas is an integral part of the Texas Intrastate System. Collectively, the Texas Intrastate System serves important natural gas producing regions and commercial markets in Texas, including Corpus Christi, the San Antonio/Austin area, the Beaumont/Orange area and the Houston area, including the Houston Ship Channel industrial market.

The 173-mile Sherman Extension pipeline, which is part of our Enterprise Texas pipeline system, was completed in late February 2009 and is capable of transporting up to 1.2 Bcf/d of natural gas from the Barnett Shale supply basin in North Texas. The Sherman Extension provides producers with connections to third party interstate pipelines having access to markets outside of Texas. An aggregate of 1.0 Bcf/d of the Sherman Extension's throughput capacity has been contracted for by customers, including EPO, under long-term contracts.

In July 2010, we completed and placed the final segment of our Trinity River Lateral natural gas pipeline into service. The Trinity River Lateral pipeline, which is part of our Enterprise Texas pipeline system, extends approximately 42 miles from the Trinity River Basin north of Arlington, Texas to an interconnect with our Sherman Extension pipeline near Justin, Texas. The Trinity River Lateral provides producers in Tarrant and Denton Counties in North Texas with up to 1.0 Bcf/d of production takeaway capacity.

In April 2011, we completed and placed a fifth storage cavern at the Wilson natural gas storage facility into service. We own and operate this new cavern, which provides us with an additional 6.1 Bcf of usable natural gas storage capacity.

§ The Acadian Gas System purchases, transports, stores and resells natural gas in Louisiana. The Acadian Gas System is comprised of the 590-mile Cypress pipeline, 442-mile Acadian pipeline, 270-mile Haynesville Extension and 27-mile Evangeline pipeline. The Acadian Gas System includes a leased natural gas storage facility at Napoleonville, Louisiana that is an integral part of its pipeline operations. The Acadian Gas pipeline system links natural gas supplies from onshore Gulf Coast (including the Haynesville Shale supply basin) and offshore Gulf of Mexico developments with local gas distribution companies, electric generation plants and industrial customers, located primarily in the natural gas market area of the Baton Rouge – New Orleans – Mississippi River corridor.

In November 2011, commercial operations on the Haynesville Extension of our Acadian Gas System commenced. As a result of completing the Haynesville Extension project, we have provided producers in Louisiana's Haynesville and Bossier Shale plays with access to 1.8 Bcf/d of incremental natural gas takeaway capacity. As an extension of our Acadian Gas System, the Haynesville Extension offers producers access to more than 150 end-user customer service locations along the Mississippi River industrial corridor between Baton Rouge and New Orleans, as well as the Henry Hub. The Haynesville Extension features interconnects with twelve interstate pipeline systems and is the only southerly option that avoids potential natural gas supply bottlenecks at the Perryville Hub and offers producers flow assurance and market choice to assist in maximizing the value of their natural gas.

§ The Jonah Gathering System is located in the Greater Green River Basin of southwest Wyoming. This system gathers natural gas from the Jonah and Pinedale supply fields for delivery to regional natural gas processing plants, including our Pioneer facilities, for ultimate delivery into major interstate pipelines.

§ The San Juan Gathering System serves producers in the San Juan Basin of northern New Mexico and southern Colorado. This system gathers natural gas from production wells located in the San Juan Basin and delivers the natural gas either directly into major interstate pipelines or to regional processing and treating plants, including our

Chaco processing facility and Val Verde treating plant located in New Mexico, for ultimate delivery into major interstate pipelines.

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- § The Piceance Basin Gathering System consists of a network of gathering pipelines located in the Piceance Basin of northwestern Colorado. The Piceance Creek Gathering System gathers natural gas throughout the Piceance Basin to our Meeker natural gas processing complex for ultimate delivery into the White River Hub and other major interstate pipelines.

- § The White River Hub is a regulated interstate natural gas transportation hub facility. The White River Hub connects to six interstate natural gas pipelines in northwest Colorado and has a gross capacity of 3 Bcf/d of natural gas (1.5 Bcf/d net to our 50% ownership interest).

- § The Haynesville Gathering Systems consist of the 203-mile State Line gathering system, the 56-mile South East Mansfield gathering system and the 36-mile South East Stanley gathering system. Our Haynesville Gathering Systems gather natural gas produced from the Haynesville and Bossier Shale supply basins and the Cotton Valley and Taylor Sand formations in Louisiana and eastern Texas for delivery to several downstream markets including the Haynesville Extension of our Acadian Gas System.

- § The Fairplay Gathering System gathers natural gas produced from the Haynesville and Bossier Shale supply basins and the Cotton Valley and Taylor Sand formations within Panola and Rusk Counties in East Texas. This system is expected to extend our asset base through potential future interconnects with our Texas Intrastate System, support deliveries of NGLs into our Panola liquids pipeline and further to our fractionation, storage and distribution complex in Mont Belvieu, Texas.

- § The Carlsbad Gathering System gathers natural gas from the Permian Basin region of Texas and New Mexico for delivery to natural gas processing plants, including our Chaparral and Carlsbad plants, as well as delivery into the El Paso Natural Gas and Transwestern pipelines.

Onshore Crude Oil Pipelines & Services

Our Onshore Crude Oil Pipelines & Services business segment includes approximately 5,250 miles of onshore crude oil pipelines and 12 MMBbls of above-ground storage tank capacity. This segment also includes our crude oil marketing activities.

Onshore crude oil pipelines, terminals and related marketing activities. Our onshore crude oil pipeline systems gather and transport crude oil primarily in New Mexico, Oklahoma and Texas to refineries, centralized storage terminals and connecting pipelines. Revenue from crude oil transportation is generally based upon a fixed fee per barrel transported multiplied by the volume delivered. Accordingly, the results of operations for this business are generally dependent upon the volume of crude oil transported and the level of fees charged to customers (including those charged internally, which are eliminated in the preparation of our Consolidated Financial Statements). The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC.

We own crude oil terminal facilities in Cushing, Oklahoma and Midland, Texas that are used to store crude oil volumes for us and our customers. Under our crude oil terminaling agreements, we charge customers for crude oil storage based on the number of days a customer has volumes in storage multiplied by a contractual storage fee. With respect to storage capacity reservation agreements, we collect a fee for reserving storage capacity for customers at our terminals. The customers pay reservation fees based on the level of storage capacity reserved rather than the actual volumes stored. In addition, we charge our customers throughput (or "pumpover") fees based on volumes withdrawn from our terminals. Lastly, we provide fee-based trade documentation services whereby we document the transfer of title for crude oil volumes transacted between buyers and sellers at our terminals. In general, the profitability of our crude oil terminaling operations is dependent upon the level of storage capacity reserved by our customers, the volume of product withdrawn from our terminals and the level of fees charged (including those charged internally, which are eliminated in the preparation of our Consolidated Financial Statements).

Our crude oil marketing activities generate revenues from the sale and delivery of crude oil obtained from producers or on the open market. In general, the sales prices referenced in these contracts are market-based and may include pricing differentials for such factors as delivery location or crude oil composition. To limit the exposure of

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our crude oil marketing activities to commodity price risk, our purchases and sales of crude oil are generally contracted to occur within the same calendar month. We also use derivative instruments to mitigate our exposure to commodity price risks associated with our crude oil marketing business.

Seasonality. Our onshore crude oil pipelines and related activities typically exhibit little to no effects of seasonality. However, our onshore pipelines situated along the Texas Gulf Coast may be affected by weather events such as hurricanes and tropical storms, which generally arise during the summer and fall months.

Competition. Within their respective market areas, our onshore crude oil pipelines, terminals and related marketing activities compete with other crude oil pipeline companies, major integrated oil companies and their marketing affiliates, financial institutions with trading platforms and independent crude oil gathering and marketing companies. The onshore crude oil business can be characterized by thin operating margins and strong competition for supplies of crude oil. Competition is based primarily on quality of customer service, competitive pricing and proximity to customers and other market hubs.

Properties. The following table summarizes the significant crude oil pipelines and related terminal assets included in our Onshore Crude Oil Pipelines & Services business segment at February 1, 2012:

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Net Usable Storage Capacity (MMBbls)
Crude oil pipelines:				
Seaway Crude Pipeline System	Texas, Oklahoma	50.0% (1)	546	3.4
Red River System	Texas, Oklahoma	100.0%	2,002	1.2
South Texas Crude Oil Pipeline System	Texas	100.0%	1,346	1.1
West Texas System	Texas, New Mexico	100.0%	614	0.4
Basin Pipeline System	Texas, New Mexico, Oklahoma	13.0% (2)	519	0.8
Other (three systems) (3)	Texas, Oklahoma	100.0%	227	0.3
Total miles			5,254	
Crude oil terminals:				
Cushing terminal	Oklahoma	100.0%		3.1
Midland terminal	Texas	100.0%		1.5
Total capacity				11.8

(1) Our ownership interest in the Seaway Crude Pipeline System is held indirectly through our equity method investment in Seaway Crude Pipeline Company (“Seaway”). Storage capacity presented for Seaway Crude Pipeline System consists of our Jones Creek and Texas City facilities.
(2) We proportionately consolidate our undivided interest in the Basin Pipeline System.
(3) Includes our Azelea, Mesquite and Sharon Ridge crude oil gathering systems located in Oklahoma and Texas.

The maximum number of barrels that our crude oil pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon product composition and demand levels at various delivery points, the exact capacities of our crude oil pipelines cannot be reliably determined. We measure the utilization rates of such pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 678 MBPD, 670 MBPD and 680 MBPD during the years ended December 31, 2011, 2010 and 2009, respectively.

Our crude oil marketing activities utilize a fleet of approximately 400 tractor-trailer tank trucks, the majority of which are leased from third parties. In addition, we operate 17 crude oil truck terminal facilities in Texas, Oklahoma and North Dakota.

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The following information highlights the general use of each of our principal crude oil pipelines and terminals, all of which we operate with the exception of the Basin Pipeline System.

§ The Seaway Crude Pipeline System is a regulated system that consists of a 503-mile long-haul pipeline connecting markets in Freeport, Texas and Cushing, Oklahoma, 43 miles of gathering and delivery pipelines in Texas and a terminal facility at Texas City, Texas.

In November 2011, we and Enbridge Inc. agreed to reverse the direction of crude oil flows on the Seaway pipeline to enable it to transport oil from the oversupplied Cushing hub to U.S. Gulf Coast refiners. The Seaway pipeline could operate in reversed service with an initial capacity of 150 MBPD during the second quarter of 2012. Following pump station additions and other modifications, which are anticipated to be completed in the first quarter of 2013, we anticipate the capacity of the reversed Seaway pipeline will be up to 400 MBPD (assuming a mix of light and heavy grades of crude oil). In addition, we are constructing related storage assets and connecting pipelines in the Houston, Texas area that are expected to be completed in mid-2012 and early 2014, respectively. For additional information regarding this project, see "Significant Recent Developments—Plans with Enbridge to Reverse the Seaway Pipeline" under Item 7 of this annual report.

§ The Red River System is a regulated pipeline that transports crude oil from North Texas to southern Oklahoma for delivery to either two local refineries or pipeline interconnects for further transportation to Cushing, Oklahoma.

§ The South Texas Crude Oil Pipeline System transports crude oil originating in South Texas including production from the Eagle Ford Shale supply basin to refineries in the Houston, Texas area. In May 2011, we announced plans to build an 80-mile extension of the South Texas Crude Oil Pipeline System (the "Phase II project"), which would allow us to serve growing production areas in the southwestern portion of the Eagle Ford Shale supply basin. The Phase II project, which is being designed with a crude oil transportation capacity of 200 MBPD, will originate at Lyssy, Texas in Karnes County (at the terminus of our previously announced 140-mile Phase I segment) and extend to Gardendale, Texas in La Salle County, where a new central delivery point is planned for construction that will feature 0.5 MMBbls of crude oil storage. The system's Phase I pipeline expansion project, which is expected to have a crude oil transportation capacity of 350 MBPD, originates at Sealy, Texas in Austin County and extends to Lyssy, Texas. Phase I of the expansion project includes construction of an aggregate 2.4 MMBbls of crude oil storage capacity along the new pipeline, including 0.6 MMBbls at Lyssy, Texas, 0.2 MMBbls at Milton, Texas, 0.4 MMBbls at Marshall, Texas, and 1.2 MMBbls at Sealy, Texas. Phase I of the project is forecast to begin service by the second quarter of 2012, with Phase II set to commence operations in the first quarter of 2013. For additional information regarding this project, see "Significant Recent Developments—Expansion of Our South Texas Crude Oil Pipeline System" under Item 7 of this annual report.

§ The West Texas System connects crude oil gathering systems in West Texas and southeast New Mexico to our terminal facility in Midland, Texas.

§ The Basin Pipeline System transports crude oil from the Permian Basin in West Texas and southern New Mexico to Cushing, Oklahoma.

§ The Cushing and Midland terminals provide crude oil storage, pumpover and trade documentation services. Our terminal in Cushing, Oklahoma has 19 above-ground storage tanks with aggregate crude oil storage capacity of 3.1 MMBbls. The Midland terminal has a storage capacity of 1.5 MMBbls through the use of 12 above-ground storage tanks.

We are constructing a new crude oil terminal, our Enterprise Crude Houston ("ECHO") facility, southeast of Houston in connection with the expansion of our South Texas System and the planned reversal of the Seaway pipeline. The

ECHO terminal will provide shippers with access to major refiners located in the Houston and Texas City, Texas refining hub representing more than 2 MMBPD of refining capacity. The ECHO terminal will also have connections to marine facilities which will provide connectivity to any refinery on the U.S. Gulf Coast. The ECHO facility is scheduled to begin service in mid-2012 and will initially have 0.8 MMBbls of crude oil storage capacity.

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We will own and operate the ECHO terminal. In February 2012, we announced an expansion of our ECHO facility, which will provide capability to increase its crude oil storage capacity to approximately 6 MMBbls.

Seaway plans to build a 45-mile pipeline that will link its pipeline to our ECHO terminal. Completion of this pipeline segment is expected in the first quarter of 2013. In addition, Seaway plans to build an 85-mile pipeline from our ECHO facility to the Port Arthur/Beaumont, Texas refining center that would provide shippers access to the region's heavy oil refining capabilities. Completion of this pipeline segment is expected in early 2014.

Offshore Pipelines & Services

Our Offshore Pipelines & Services business segment serves some of the most active drilling and development regions, including deepwater production fields, in the northern Gulf of Mexico offshore Texas, Louisiana, Mississippi and Alabama. This segment includes approximately 1,330 miles of offshore natural gas pipelines, approximately 980 miles of offshore crude oil pipelines and six offshore hub platforms.

Our offshore Gulf of Mexico pipelines provide for the gathering and transportation of natural gas or crude oil. In general, revenue from our offshore pipelines is derived from fee-based agreements whereby the customer is charged a fee per unit of volume gathered or transported (typically per MMBtu of natural gas or per barrel of crude oil) multiplied by the volume delivered. These agreements tend to be long-term, often involving life-of-reserve commitments with both firm and interruptible components.

Poseidon Oil Pipeline Company, L.L.C. ("Poseidon"), in which we have a 36% equity method investment, purchases crude oil from producers and shippers at a receipt point (at a fixed or index-based price less a location differential) and then sells like quantities of crude oil at onshore Louisiana locations (at the same fixed or index-based price, as applicable). When these transactions are completed with the same counterparty, Poseidon recognizes net revenues from such arrangements based on the location differential, which represents the fee charged for providing transportation services on the Poseidon Oil Pipeline System. If Poseidon purchases and sells like crude oil volumes with different counterparties, Poseidon recognizes revenues based on the crude oil sales price multiplied by the volume sold.

Our offshore platforms are integral components of our pipeline operations. In general, platforms are critical components of the energy-related infrastructure in the Gulf of Mexico, supporting drilling and producing operations, and therefore play a key role in the overall development of offshore crude oil and natural gas reserves. Platforms are used to: interconnect the offshore pipeline network; provide an efficient means to perform pipeline maintenance; locate compression, separation and production handling equipment and similar assets; and conduct drilling operations during the initial development phase of an oil and natural gas property. Revenues from offshore platform services generally consist of demand fees and commodity charges. Demand fees are similar to firm capacity reservation agreements for a pipeline in that they are charged to a customer regardless of the volume the customer actually delivers to the platform. Revenue from commodity charges is based on a fixed-fee per unit of volume delivered to the platform (typically per MMcf of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Contracts for platform services often include both demand fees and commodity charges, but demand fees generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers. For example, the producers connected to our Independence Hub platform paid us approximately $54.6 million of demand fees annually from March 2007 through February 2012. These demand fees are in addition to commodity charges they pay us based on volumes delivered to the platform.

In April 2010, in an event unrelated to Enterprise's operations, the Deepwater Horizon drilling rig caught fire and sank in the Gulf of Mexico, resulting in an oil spill. As a result, governmental agencies took actions to halt most drilling operations in the Gulf of Mexico for a period of time extending into October 2010. The moratorium has impacted the timing of exploration and production activities in the Gulf of Mexico. For additional information regarding the Deepwater Horizon incident and its effects on Gulf of Mexico exploration and production activities, see "—Additional regulations that cause delays or deter new offshore oil and gas drilling could have a material adverse effect on our financial position, results of operations and cash flows" on page 55 under Item 1A of this annual report.

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Seasonality. Our offshore operations exhibit little to no effects of seasonality; however, they may be affected by weather events such as hurricanes and tropical storms in the Gulf of Mexico that generally arise during the summer and fall months. See Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding weather-related risks and insurance matters.

Competition. Within their respective market areas, our offshore pipelines compete with other offshore pipelines primarily on the basis of fees charged, available throughput capacity, connections to downstream markets and proximity and access to existing reserves. Our competitors may have access to greater capital resources than we do, which could enable them to address business opportunities in the Gulf of Mexico more quickly than we can.

Properties. The following table summarizes the significant assets included in our Offshore Pipelines & Services business segment at February 1, 2012:

Description of Asset	Our Ownership Interest	Length (Miles)	Water Depth (Feet)	Approximate Net Capacity Natural Gas (MMcf/d)	Approximate Net Capacity Crude Oil (MPBD)
Offshore natural gas pipelines:					
Independence Trail	100.0%	134		1,000	
Viosca Knoll Gathering System	100.0%	137		600	
High Island Offshore System	100.0%	291		500	
Falcon Natural Gas Pipeline	100.0%	14		400	
Green Canyon Laterals	Various (1)	70		361	
Anaconda Gathering System	100.0%	183		300	
Manta Ray Offshore Gathering System	25.7% (2)	250		206	
Nautilus System	25.7% (2)	101		154	
Nemo Gathering System	33.9% (3)	24		102	
VESCO Gathering System	13.1% (4)	125		65	
Total miles		1,329			
Offshore crude oil pipelines:					
Cameron Highway Oil Pipeline	50.0% (5)	374			250
Shenzi Oil Pipeline	100.0%	83			230
Poseidon Oil Pipeline System	36.0% (6)	359			155
Allegheny Oil Pipeline	100.0%	43			140
Marco Polo Oil Pipeline	100.0%	37			120
Constitution Oil Pipeline	100.0%	67			80
Typhoon Oil Pipeline	100.0%	17			80
Tarantula Oil Pipeline	100.0%	4			30
Total miles		984			
Offshore hub platforms:					
Independence Hub	80.0% (7)		8,000	800	N/A
Marco Polo	50.0% (8)		4,300	150	60
Viosca Knoll 817	100.0%		671	145	5
Garden Banks 72	50.0% (9)		518	113	18
East Cameron 373	100.0%		441	195	3
Falcon Nest	100.0%		389	400	3

(1) We proportionately consolidate our undivided interests, which range from 2.7% to 75.0%, in 64 miles of the Green Canyon Lateral pipelines. The remainder of the laterals are wholly owned.
(2) Our ownership interests in the Manta Ray Offshore Gathering System and the Nautilus System are held indirectly through our equity method investment in Neptune Pipeline Company, L.L.C. ("Neptune").
(3) Our ownership interest in the Nemo Gathering System is held indirectly through our equity method investment in Nemo Gathering Company, LLC ("Nemo").
(4) Our ownership interest in the VESCO Gathering System is held indirectly through our equity method investment in VESCO. This system is integral to our natural gas processing operations; therefore, our equity method investment in VESCO is accounted for under our NGL Pipelines & Services business segment.
(5) Our ownership interest in the Cameron Highway Oil Pipeline is held indirectly through our equity method investment in Cameron Highway Oil Pipeline Company ("Cameron Highway").
(6) Our ownership interest in the Poseidon Oil Pipeline System is held indirectly through our equity method investment in Poseidon.
(7) We own an 80% consolidated interest in the Independence Hub platform through our majority owned subsidiary, Independence Hub, LLC.
(8) Our ownership interest in the Marco Polo platform is held indirectly through our equity method investment in Deepwater Gateway, L.L.C. ("Deepwater Gateway").
(9) We proportionately consolidate our undivided interest in the Garden Banks 72 platform.

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We operate our offshore natural gas pipelines, with the exception of the VESCO Gathering System, Manta Ray Offshore Gathering System, Nautilus System, Nemo Gathering System and certain components of the Green Canyon Laterals. On a weighted-average basis, aggregate utilization rates for our offshore natural gas pipelines were approximately 27.4%, 23.8% and 22.3% during the years ended December 31, 2011, 2010 and 2009, respectively. For recently constructed assets, utilization rates reflect the periods since such assets were placed into service.

The following information highlights the general use of each of our principal Gulf of Mexico offshore natural gas pipelines.

§ The Independence Trail natural gas pipeline transports natural gas that originates at our Independence Hub platform and at a pipeline interconnect downstream of our Independence Hub platform. During 2011, we established a new pipeline interconnect on the Independence Trail pipeline to serve an additional producer. Our Independence Trail pipeline delivers natural gas to the Tennessee Gas Pipeline at a pipeline interconnect on our West Delta 68 platform. Natural gas transported on the Independence Trail pipeline originates from production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico.

§ The Viosca Knoll Gathering System transports natural gas from producing fields located in the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico to several major interstate pipelines, including the Columbia Gulf, Southern Natural, Transco, Dauphin Island Gathering System and Destin Pipelines.

§ The High Island Offshore System ("HIOS") transports natural gas from producing fields located in the Galveston, Garden Banks, West Cameron, High Island and East Breaks areas of the Gulf of Mexico to the ANR pipeline system and Tennessee Gas Pipeline. HIOS includes 205 miles of pipeline and eight pipeline junction and service platforms that are regulated by the FERC. In addition, this system includes the non-regulated 86-mile East Breaks System that connects HIOS to the Hoover-Diana deepwater platform located in Alaminos Canyon Block 25.

§ The Falcon Natural Gas Pipeline delivers natural gas processed at our Falcon Nest platform to a connection with the Central Texas Gathering System located at the Brazos Addition Block 133 platform.

§ The Green Canyon Laterals consist of 10 pipeline laterals (which are extensions of natural gas pipelines) that transport natural gas to downstream pipelines, including HIOS.

§ The Anaconda Gathering System connects our Marco Polo platform and the third party owned Constitution and Typhoon platforms to the Nautilus System. Connection to the Nautilus System was made possible via the 46-mile Anaconda Extension pipeline we constructed and placed into service during July 2011.

§ The Manta Ray Offshore Gathering System transports natural gas from producing fields located in the Green Canyon, Southern Green Canyon, Ship Shoal, South Timbalier and Ewing Bank areas of the Gulf of Mexico to numerous downstream pipelines, including our Nautilus System.

§ The Nautilus System connects our Anaconda Gathering System and Manta Ray Offshore Gathering System to our Neptune natural gas processing plant located in southern Louisiana.

§ The Nemo Gathering System transports natural gas from Green Canyon developments to an interconnect with our Manta Ray Offshore Gathering System.

§ The VESCO Gathering System is a regulated natural gas pipeline system associated with the Venice natural gas processing plant in south Louisiana.

The following information highlights the general use of each of our principal Gulf of Mexico offshore crude oil pipelines, all of which we operate. On a weighted-average basis, aggregate utilization rates for our offshore crude oil pipelines were approximately 25.7%, 29.5% and 28.7% during the years ended December 31,

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2011, 2010 and 2009, respectively. For recently constructed assets, utilization rates reflect the periods since such assets were placed into service.

§ The Cameron Highway Oil Pipeline gathers crude oil production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas. This system includes two pipeline junction platforms.

§ The Shenzi Oil Pipeline provides gathering services from the BHP Billiton Plc-operated Shenzi production field located in the South Green Canyon area of the central Gulf of Mexico. The Shenzi Oil Pipeline allows producers to access our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

§ The Poseidon Oil Pipeline System gathers production from the outer continental shelf and deepwater areas of the Gulf of Mexico for delivery to onshore locations in south Louisiana. This system includes one pipeline junction platform.

§ The Allegheny Oil Pipeline connects the Allegheny and South Timbalier 316 platforms in the Green Canyon area of the Gulf of Mexico with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

§ The Marco Polo Oil Pipeline transports crude oil from our Marco Polo oil platform to an interconnect with our Allegheny Oil Pipeline in Green Canyon Block 164.

§ The Constitution Oil Pipeline serves the Constitution and Ticonderoga fields located in the central Gulf of Mexico. The Constitution Oil Pipeline connects with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at a pipeline junction platform.

In January 2012, we announced the execution of crude oil transportation agreements with a consortium of six Gulf of Mexico producers that will provide the necessary support for construction of our 149-mile SEKCO Oil Pipeline, which would serve the Lucius oil and gas field located in the southern Keathley Canyon area of the deepwater central Gulf of Mexico. The pipeline will be constructed and owned by Southeast Keathley Canyon Pipeline Company, L.L.C. ("SEKCO"), which is a 50/50 joint venture owned by us and Genesis Energy, L.P. ("Genesis"). We will serve as construction manager and operator of the SEKCO Oil Pipeline, which we expect to begin service by mid-2014. For additional information regarding this project, see "Significant Recent Developments—Plans to Construct a Crude Oil Pipeline in the Gulf of Mexico with Genesis" under Item 7 of this annual report.

With respect to natural gas processing capacity, the utilization rates (on a weighted-average basis) of our offshore platforms were approximately 22.5%, 28.5% and 39.4% during the years ended December 31, 2011, 2010 and 2009, respectively. With respect to crude oil processing capacity, the utilization rates (on a weighted-average basis) of our offshore platforms were approximately 19.3%, 19.2% and 13.6% during the years ended December 31, 2011, 2010 and 2009, respectively. For recently constructed assets, these rates reflect the periods since the dates such assets were placed into service. In addition to our offshore hub platforms, we also own or have an ownership interest in 13 pipeline junction and service platforms. Our pipeline junction and service platforms do not have processing capacity.

The following information highlights the general use of each of our principal Gulf of Mexico offshore hub platforms. We operate these platforms with the exception of the Independence Hub and Marco Polo platforms.

§ The Independence Hub platform is located in Mississippi Canyon Block 920. This platform processes natural gas gathered from deepwater production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico.

§ The Marco Polo platform, which is located in Green Canyon Block 608, processes crude oil and natural gas from the Marco Polo, K2, K2 North and Genghis Khan fields. These fields are located in the South Green Canyon area of the Gulf of Mexico.

§ The Viosca Knoll 817 platform is centrally located on our Viosca Knoll Gathering System. This platform primarily serves as a base for gathering deepwater production in the area, including the Ram Powell development.

§ The Garden Banks 72 platform serves as a base for gathering deepwater production from the Garden Banks Block 161 development and the Garden Banks Block 378 and 158 leases. This platform also serves as a junction platform for our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

§ The East Cameron 373 platform serves as the host for East Cameron Block 373 production and also processes production from Garden Banks Blocks 108, 152, 197, 200 and 201.

§ The Falcon Nest platform, which is located in the Mustang Island Block 103 area of the Gulf of Mexico, processes natural gas from the Falcon field.

Petrochemical & Refined Products Services

Our Petrochemical & Refined Products Services business segment consists of (i) propylene fractionation plants, pipelines and related marketing activities; (ii) a butane isomerization facility and related pipeline system; (iii) octane enhancement and high purity isobutylene production facilities; (iv) refined products pipelines, including our Products Pipeline System (as defined below), and related marketing activities; and (v) marine transportation and other services.

Propylene fractionation and related activities. Our propylene fractionation and related activities primarily consist of seven propylene fractionation plants (six located in Mont Belvieu, Texas and a seventh in Baton Rouge, Louisiana), propylene pipeline systems aggregating approximately 680 miles in length and related petrochemical marketing activities. This business includes an export facility and associated above-ground polymer grade propylene storage spheres located in Seabrook, Texas.

In general, propylene fractionation plants separate refinery grade propylene, which is a mixture of propane and propylene, into either polymer grade propylene or chemical grade propylene along with by-products of propane and mixed butane. Polymer grade and chemical grade propylene can also be produced as a by-product of ethylene production. The demand for polymer grade propylene primarily relates to the manufacture of polypropylene, which has a variety of end uses including packaging film, fiber for carpets and upholstery and molded plastic parts for appliances and automotive, houseware and medical products. Chemical grade propylene is a basic petrochemical used in the manufacturing of plastics, synthetic fibers and foams.

Results of operations for our polymer grade propylene plants are generally dependent upon toll processing arrangements and petrochemical marketing activities. The toll processing arrangements typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of propylene fractionation. Our petrochemical marketing activities include the purchase and fractionation of refinery grade propylene obtained in the open market and generate revenues from the sale and delivery of products obtained through propylene fractionation. In general, we sell our petrochemical products at market-based prices, which may include pricing differentials for such factors as delivery location. The majority of revenues from our propylene pipelines are based upon a transportation fee per unit of volume multiplied by the volume delivered to the customer. Propylene transportation agreements may include deficiency fee provisions whereby the customer pays us a fee if certain volume thresholds are not met over a contractual term.

As part of our petrochemical marketing activities, we have several long-term refinery grade propylene purchase and polymer grade propylene sales agreements. To limit the exposure of our petrochemical marketing activities to commodity price risk, we attempt to match the timing and price of our feedstock purchases with those of the sales of end products.

Butane isomerization. Our butane isomerization business includes three butamer reactor units and eight associated deisobutanizer units located in Mont Belvieu, Texas, which comprise the largest commercial isomerization facility in the U.S. In addition, this business includes a 70-mile pipeline system used to transport high-purity isobutane from Mont Belvieu, Texas to Port Neches, Texas.

Our commercial isomerization units convert normal butane into mixed butane, which is subsequently fractionated into isobutane, high-purity isobutane and residual normal butane. The primary uses of isobutane are for the production of propylene oxide, isooctane, isobutylene and alkylate for motor gasoline. The demand for commercial isomerization services depends upon the industry's requirements for isobutane and high-purity isobutane in excess of the isobutane produced through the process of NGL fractionation and refinery operations.

The results of operation of this business are generally dependent upon the volume of normal and mixed butanes processed and the level of toll processing fees charged to customers. These processing arrangements typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of isomerization. Our isomerization facility provides processing services to meet the needs of third party customers and our other businesses, including our NGL marketing activities and octane enhancement production facility. Our isomerization business also generates revenues from the sale of natural gasoline created as a by-product of the isomerization process.

Octane enhancement and high purity isobutylene. We own and operate an octane enhancement production facility located in Mont Belvieu, Texas that is designed to produce isooctane, isobutylene and methyl tertiary butyl ether ("MTBE"). The products produced by this facility are used in reformulated motor gasoline blends to increase octane values. The high-purity isobutane feedstocks consumed in the production of these products are supplied by our isomerization units. To the extent that MTBE is produced at our Mont Belvieu facility, it is strictly sold into the export market.

The results of operations of this business are generally dependent upon the sale and delivery of products produced. In general, we sell our octane enhancement products at market-based prices, which may include pricing differentials for such factors as delivery location. We attempt to mitigate price risk by entering into certain commodity hedging transactions.

We own a facility located on the Houston Ship Channel that produces high purity isobutylene ("HPIB"). The primary feedstock for this plant is produced by our octane enhancement facility located at our Mont Belvieu complex. HPIB is used in the production of alkylated phenols used as antioxidants, lube oil additives, butyl rubber and resins. The results of operations of this business are generally dependent upon the sale and delivery of products produced. In general, we sell HPIB at market-based prices, which may include pricing differentials for such factors as delivery location.

Refined products pipelines and related activities. Refined products pipelines and related activities primarily consist of our (i) Products Pipeline System, (ii) equity method investment in Centennial Pipeline LLC ("Centennial") and (iii) refined products marketing activities. Our Products Pipeline System consists of (i) a regulated 4,313-mile interstate pipeline system that generally extends in a northeasterly direction from the upper Texas Gulf Coast to the northeast U.S., (ii) 326 miles of intrastate pipelines in Texas and (iii) related terminal operations.

The Products Pipeline System transports refined products, and to a lesser extent, petrochemicals such as ethylene and propylene and NGLs such as propane and normal butane. These refined products are produced by refineries and include gasoline, diesel fuel, aviation fuel, kerosene, distillates and heating oil. Refined products also include blend stocks such as raffinate and naphtha. Blend stocks are primarily used to produce gasoline or as a feedstock for certain petrochemicals. The Centennial Pipeline intersects our Products Pipeline System near Creal Springs, Illinois, and effectively loops the Products Pipeline System between Beaumont, Texas and south Illinois. Looping the Products Pipeline System permits effective supply of products to points south of Illinois as well as incremental product supply capacity to other Midcontinent markets.

Our refined products pipelines and related activities include six refined products truck terminals and 13 storage terminals located along the Products Pipeline System. In addition, we have refined products terminals located at Aberdeen, Mississippi and Boligee, Alabama adjacent to the Tombigbee River and on the Houston Ship Channel in Pasadena, Texas.

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The results of operations of our refined products pipelines are primarily dependent on the tariffs charged to customers to transport products and the volume delivered. The tariffs charged for such services are either contractual or regulated by governmental agencies, including the FERC. The results of our storage and terminal assets are primarily dependent on the volume and associated fees charged to customers (including those charged internally, which are eliminated in the preparation of our Consolidated Financial Statements). Our related marketing activities generate revenues from the sale and delivery of refined products obtained from third parties on the open market. In general, we sell our refined products at market-based prices, which may include pricing differentials for such factors as delivery location. Our refined products marketing sales contracts may also include forward product sales contracts.

Marine transportation and other services. Our marine transportation business consists of tow boats and tank barges that are primarily used to transport refined products, crude oil, asphalt, condensate, heavy fuel oil, liquefied petroleum gas and other petroleum products along key inland and intracoastal U.S. waterways. Our marine transportation assets service refinery and storage terminal customers along the Mississippi River, the intracoastal waterway between Texas and Florida and the Tennessee-Tombigbee Waterway system. We own a shipyard and repair facility located in Houma, Louisiana and marine fleeting facilities in Bourg, Louisiana and Channelview, Texas.

The results of operations of our marine transportation business are generally dependent upon the level of fees charged to transport cargo. These transportation services are typically provided under term contracts (also referred to as affreightment contracts), which are agreements with specific customers to transport cargo from within designated operating areas at set day rates or a set fee per cargo movement.

Other services consist of the distribution of lubrication oils and specialty chemicals and the bulk transportation of fuels by truck, principally in Oklahoma, Texas, New Mexico, Kansas and the Rocky Mountain region of the U.S. In addition, our wholly owned subsidiary, Enterprise Products Transportation Company LLC (“ETC”), utilizes a fleet of approximately 775 tractor-trailer tank trucks to transport NGLs and petrochemicals. ETC’s fleet is supported by 26 truck terminals that we operate in various locations throughout the U.S.

The results of operations from other non-marine services are dependent on the sales price or transportation fees that we charge our customers and the volume sold or transported.

Seasonality. Overall, the propylene fractionation business exhibits little seasonality. Our isomerization operations experience slightly higher levels of demand in the spring and summer months due to increased demand for isobutane-based fuel additives used in the production of motor gasoline. Likewise, octane additive prices have been stronger during the April to September period of each year, which corresponds with the summer driving season, when motor gasoline demand increases.

Our refined products pipelines and related activities exhibit seasonality based upon the mix of products delivered and the weather and economic conditions in the geographic areas being served. Refined products volumes are generally higher during the second and third quarters of each year because of greater demand for motor gasoline during the spring and summer driving seasons. NGL transportation volumes on the Products Pipeline System are generally higher from October through March due to higher demand for propane (for residential heating) and normal butane (for blending in motor gasoline).

Our marine transportation business exhibits some seasonal variation. Demand for motor gasoline and asphalt is generally stronger in the spring and summer months due to the summer driving season and when weather allows for more efficient road construction. Weather events, such as hurricanes and tropical storms in the Gulf of Mexico, can adversely impact both the offshore and inland businesses. Generally during the winter months, cold weather and ice can negatively impact the inland operations on the upper Mississippi and Illinois rivers.

Competition. We compete with numerous producers of polymer grade propylene, which include many of the major refiners and petrochemical companies located along the Gulf Coast. Generally, our propylene fractionation business competes in terms of the level of toll processing fees charged and access to pipeline and storage infrastructure. Our petrochemical marketing activities encounter competition from fully integrated oil companies and various petrochemical companies. Our petrochemical marketing competitors have varying levels of

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financial and personnel resources and competition generally revolves around price, quality of customer service, logistics and location.

With respect to our isomerization operations, we compete primarily with facilities located in Kansas, Louisiana and New Mexico. Competitive factors affecting this business include the level of toll processing fees charged, the quality of isobutane that can be produced and access to pipeline and storage supporting infrastructure. We compete with other octane additive manufacturing companies primarily on the basis of price.

The Products Pipeline System's most significant competitors are third party pipelines in the areas where it delivers products. Competition among common carrier pipelines is based primarily on transportation fees, quality of customer service and proximity to end users. Trucks, barges and railroads competitively deliver products into some of the areas served by our Products Pipeline System and river terminals. The Products Pipeline System faces competition from rail and pipeline movements of NGLs from Canada and waterborne imports into terminals located along the upper East Coast.

Our marine transportation business competes with other inland marine transportation companies as well as providers of other modes of transportation, such as rail tank cars, tractor-trailer tank trucks and, to a limited extent, pipelines. Competition within the marine transportation business is largely based on price.

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Properties. The following table summarizes the significant production facilities and petrochemical pipelines included in our Petrochemical & Refined Products Services business segment at February 1, 2012, all of which we operate.

Description of Asset	Location(s)	Our Ownership Interest	Net Plant Capacity (MBPD)	Total Plant Capacity (MBPD)	Length (Miles)
Propylene fractionation facilities:					
Mont Belvieu (six units)	Texas	Various (1)	73	87	
BRPC	Louisiana	30.0% (2)	7	23	
Total capacity			80	110	
Isomerization facility:					
Mont Belvieu (3)	Texas	100.0%	116	116	
Petrochemical pipelines:					
Lou-Tex and Sabine Propylene	Texas, Louisiana	100.0%			291
North Dean Pipeline System	Texas	100.0%			149
Texas City RGP Gathering System	Texas	100.0%			86
Port Arthur RGP Gathering System	Texas	100.0%			77
Port Neches Pipeline	Texas	100.0%			70
Texas City PGP Distribution System	Texas	100.0%			35
Lake Charles PGP Pipeline	Louisiana	50.0% (4)			26
La Porte PGP Pipeline	Texas	50.0% (5)			17
Total miles					751
Octane enhancement and HPIB production facilities:					
Octane enhancement facility (6)	Texas	100.0%	12	12	
HPIB facility (7)	Texas	100.0%	4	4	
Total capacity			16	16	

(1) We proportionately consolidate our 66.7% undivided interest in three of the Mont Belvieu propylene fractionators, which have an aggregate 41 MBPD of total plant capacity. The remaining three propylene fractionators at our Mont Belvieu facility are wholly owned.
(2) Our ownership interest in the BRPC facility is held indirectly through our equity method investment in Baton Rouge Propylene Concentrator LLC ("BRPC").
(3) On a weighted-average basis, utilization rates for our Mont Belvieu isomerization facility were approximately 87.1%, 76.7% and 83.6% during the years ended December 31, 2011, 2010 and 2009, respectively.
(4) We proportionately consolidate our undivided interest in the Lake Charles PGP Pipeline.
(5) Our ownership interest in the La Porte PGP Pipeline is held indirectly through our equity method investments in La Porte Pipeline Company, L.P. and La Porte Pipeline GP, L.L.C.
(6) Our Mont Belvieu octane enhancement facility has plant capacity to produce 12.0 MBPD of isooctane or 15.5 MBPD of MTBE. On a weighted-average basis, utilization rates for our octane enhancement facility were approximately 77.4%, 71% and 50% during the years ended December 31, 2011, 2010 and 2009, respectively.
(7) We acquired our HPIB facility located on the Houston Ship Channel in November 2010. On a weighted average basis, utilization rates for our HPIB facility were 31.5% during the year ended December 31, 2011.

We produce polymer grade propylene at our Mont Belvieu, Texas propylene fractionation facility and chemical grade propylene at our BRPC facility located in Baton Rouge, Louisiana. The primary purpose of the BRPC unit is to fractionate refinery grade propylene produced by an affiliate of Exxon Mobil Corporation into chemical grade propylene. The polymer grade propylene produced by our Mont Belvieu facility is primarily for the benefit of our tolling customers and used in our petrochemical marketing activities to service long-term third party contracts. On a weighted-average basis, aggregate utilization rates of our propylene fractionation facilities were approximately 90.2%, 95.3% and 85% during the years ended December 31, 2011, 2010 and 2009, respectively. As noted previously, this business includes an export facility and above-ground polymer grade propylene storage spheres. This facility, which is located on the Houston Ship Channel in Seabrook, Texas, can load vessels at rates up to 5,000 barrels per hour.

The Lou-Tex Propylene pipeline is used to transport chemical grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas. The Sabine pipeline is used to transport polymer grade propylene from Port Arthur, Texas to a third party pipeline interconnect located in Cameron Parish, Louisiana. The North Dean Pipeline System transports refinery grade propylene from Mont Belvieu, Texas, to Point Comfort, Texas. The Port Neches Pipeline transports high purity isobutane between Mont Belvieu, Texas and Port Neches, Texas. The remainder of our petrochemical pipelines primarily transport refinery grade propylene or polymer grade propylene for customers in southeast Texas and southwest Louisiana.

The maximum number of barrels that our petrochemical pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our petrochemical pipelines cannot be reliably determined. We measure the utilization rates of such pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 117 MBPD, 135 MBPD and 124 MBPD during the years ended December 31, 2011, 2010 and 2009, respectively.

The following table summarizes the significant refined products pipelines and related terminal and storage assets included in our Petrochemical & Refined Products Services business segment at February 1, 2012:

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Net Usable Storage Capacity (MMBbls)
Refined products pipelines and terminals:				
Products Pipeline System (1)	Texas to Midwest and Northeast U.S.	100.0%	4,639	17.5
Centennial Pipeline	Texas to central Illinois	50.0% (2)	795	1.2
Other terminals (3)	Alabama, Mississippi, Texas	100.0%	n/a	1.2
Total			5,434	19.9

(1) In addition to the 17.5 MMBbls of refined products usable storage capacity, we have 5.2 MMBbls of NGL usable storage capacity that is used to support operations on our Products Pipeline System. Our NGL storage and terminal assets are accounted for under our NGL Pipelines & Services business segment.
(2) Our ownership interest in the Centennial Pipeline is held indirectly through our equity method investment in Centennial.
(3) Includes product distribution and marketing terminals located in Aberdeen, Mississippi and Boligee, Alabama having a usable storage capacity of 0.1 MMBbls and 0.5 MMBbls, respectively, and a storage terminal located in Pasadena, Texas having a usable storage capacity of 0.6 MMBbls.

The maximum number of barrels that our refined products pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our liquids pipelines cannot be reliably determined. We measure the utilization rates of such pipelines in terms of net throughput, which is based on our ownership interest. Aggregate net throughput volumes for the Products Pipeline System and Centennial Pipeline were as follows for the periods presented:

	For Year Ended December 31,		
	2011	2010	2009
Refined products transportation (MBPD)	429	511	459
Petrochemical transportation (MBPD)	121	122	118
NGL transportation (MBPD)	92	101	105

The following information highlights the general use of each of our principal refined products pipelines and related assets.

§ The Products Pipeline System is a 4,639-mile pipeline system comprised of 4,313 miles of regulated interstate pipelines and 326 miles of intrastate Texas pipelines. Refined products and NGLs are transported from the upper Texas Gulf Coast through two parallel pipelines that extend to Seymour, Indiana. From Seymour, segments of the Products Pipeline System extend to the Chicago, Illinois; Lima, Ohio; Selkirk, New York; and Philadelphia (Marcus Hook), Pennsylvania areas. The Products Pipeline System east of Todhunter, Ohio is dedicated to NGL transportation and storage services. Products are delivered to various locations along the system including to terminals owned either by us or third parties and to various connecting pipelines. The Centennial Pipeline effectively loops our Products Pipeline System between Beaumont, Texas and southern Illinois. Petrochemical products are transported primarily from Mont Belvieu, Texas to Port Arthur, Texas.

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In January 2012, we announced the development of our ATEX Express long-haul ethane pipeline. This project would utilize a combination of new and existing infrastructure. The southern portion of ATEX Express would utilize a significant portion of our existing Products Pipeline System, which would be reversed to accommodate southbound delivery of ethane to the U.S. Gulf Coast. We expect that the ATEX Express will begin commercial operations in the first quarter of 2014.

§ The Centennial Pipeline is a regulated refined products pipeline system that extends from Texas to Illinois. The Centennial Pipeline extends from an origination facility located on our Products Pipeline System in Beaumont, Texas, to Bourbon, Illinois. Centennial owns a refined products storage terminal located near Creal Springs, Illinois with a gross storage capacity of 2.3 MMBbls.

The following table summarizes the significant marine transportation assets included in our Petrochemical & Refined Products Services business segment at February 1, 2012:

Class of Equipment	Number in Class	Capacity (bbl)/ Horsepower (hp) (as indicated by sign)
Inland marine transportation assets:		
Barges	21	< 25,000 bbl
Barges	96	> 25,000 bbl
Tow boats	37	< 2,000 hp
Tow boats	15	≥ 2,000 hp
Offshore marine transportation assets:		
Ocean-certified tank barges	8	≥ 20,000 bbl
Tow boats	3	< 2,000 hp
Tow boats	3	> 2,000 hp

In February 2011, we sold various tow boats and tank barge assets for approximately $53.2 million.

Our fleet of marine vessels operated at an average utilization rate of 91.8%, 91.9% and 87.5% during 2011, 2010 and 2009, respectively. These utilization rates reflect the period since we acquired these marine transportation assets.

The marine transportation industry uses tow boats as power sources and tank barges for freight capacity. We refer to the combination of the power source and freight capacity as a tow. Our inland tows generally consist of one tow boat paired with up to four tank barges, depending upon the horsepower of the tow boat, location, waterway conditions, customer requirements and prudent operational considerations. Our offshore tows generally consist of one tow boat and one ocean-certified tank barge.

Our marine transportation business is subject to regulation by the U.S. Department of Transportation ("DOT"), Department of Homeland Security, Commerce Department and the U.S. Coast Guard ("USCG") and federal and state laws.

Other Investments

This segment reflects our noncontrolling ownership interest in Energy Transfer Equity, which was accounted for using the equity method as of December 31, 2011. Energy Transfer Equity is a publicly traded partnership, which owns the general partner of Energy Transfer Partners, L.P. ("ETP") and approximately 50.2 million ETP limited partner units, as well as the general partner of Regency Energy Partners LP ("Regency") and approximately 26.3 million Regency limited partner units. Energy Transfer Equity and its affiliates are part of the midstream energy industry. Energy Transfer Equity electronically files reports with the U.S. Securities and Exchange Commission ("SEC"), including annual reports on Form 10-K and quarterly reports on Form 10-Q.

At December 31, 2011, we owned 29,303,514 limited partner common units of Energy Transfer Equity. Our limited partner interests in Energy Transfer Equity were originally acquired by Holdings in May 2007. Equity investments are part of our business strategy; however, we may from time-to-time elect to divest all or a portion of

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our equity investments in order to redeploy capital. During 2011, we sold a total of 9,672,576 Energy Transfer Equity common units for net cash proceeds of $375.2 million and recorded aggregate gains of $27.2 million on such sales.

In January 2012, we sold 22,762,636 million common units of Energy Transfer Equity in a private transaction, which generated cash proceeds of approximately $825.1 million. Proceeds from this sale were used for general company purposes, including funding capital expenditures. As of the date of this report, we own approximately 6 million common units of Energy Transfer Equity, which represent less than 3% of its common units outstanding at February 15, 2012.

Title to Properties

Our real property holdings fall into two basic categories: (i) parcels that we and our unconsolidated affiliates own in fee (e.g., we own the land upon which our Mont Belvieu NGL fractionators are constructed) and (ii) parcels in which our interests and those of our affiliates are derived from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. The fee sites upon which our significant facilities are located have been owned by us or our predecessors in title for many years without any material challenge known to us relating to title to the land upon which the assets are located, and we believe that we have satisfactory title to such fee sites. We and our affiliates have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our rights pursuant to any material lease, easement, right-of-way, permit or license, and we believe that we have satisfactory rights pursuant to all of our material leases, easements, rights-of-way, permits and licenses.

Regulation

The following sections describe the general impact of regulation on our business. Additional information regarding regulatory risks are described under Item 1A of this annual report.

Interstate Pipelines

Liquids Pipelines. Certain of our refined products, crude oil and NGL pipeline systems (collectively referred to as "liquids pipelines") are interstate common carrier pipelines subject to regulation by the FERC under the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992 ("Energy Policy Act"). The ICA prescribes that interstate tariffs must be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. FERC regulations require that interstate oil pipeline transportation rates and terms of service be filed with the FERC and posted publicly.

The ICA permits interested persons to challenge proposed new or changed rates or rules and authorizes the FERC to investigate such changes and to suspend their effectiveness for a period of up to seven months. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it may require the carrier to refund the revenues together with interest in excess of the prior tariff during the term of the investigation. The FERC may also investigate, upon complaint or on its own motion, rates and related rules that are already in effect and may order a carrier to change them prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of its complaint.

The Energy Policy Act deems just and reasonable (i.e., deems "grandfathered") liquids pipeline rates that (i) were in effect for the 12 months preceding enactment and (ii) that had not been subject to complaint, protest or investigation. Some, but not all, of our interstate liquids pipeline rates are considered grandfathered under the Energy Policy Act. Certain other rates for our interstate liquids pipeline services are charged pursuant to a FERC-approved indexing methodology, which allows a pipeline to charge rates up to a prescribed ceiling that changes annually based on the change from year-to-year in the Producer Price Index for finished goods ("PPI"). A rate increase within the indexed rate ceiling is presumed to be just and reasonable unless a protesting party can demonstrate that the rate increase is substantially in excess of the pipeline's costs. During the five-year period commencing July 1, 2006 and ending June 30, 2011, liquids pipelines charging indexed rates were permitted to adjust their indexed ceilings annually by the PPI plus 1.3%. During the five-year period commencing July 1, 2011 and ending June 30, 2016, liquids pipelines charging indexed rates are permitted to adjust their indexed ceilings annually by the PPI plus 2.65%.

As an alternative to using the indexing methodology, interstate liquids pipelines may elect to support rate filings by using a cost-of-service methodology, competitive market showings ("Market-Based Rates") or agreements with all of the pipeline's shippers that the rate is acceptable. Our Products Pipeline System has been granted permission by the FERC to utilize Market-Based Rates for all of its refined products movements other than movements to the Little Rock, Arkansas; Jonesboro, Arkansas; and Arcadia, Louisiana destination markets, which are currently subject to the PPI. However, as discussed below, movements to these three destination markets are the subject of a pending market-based rate application filed by Enterprise TE Products Pipeline Company LLC ("Enterprise TEPPCO"), an indirect wholly owned subsidiary of EPO.

Due to the complexity of ratemaking, the lawfulness of any rate is never assured. Prescribed rate methodologies for approving regulated tariff rates may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting higher costs. Changes in the FERC's methodology for approving rates could adversely affect us. In addition, challenges to our tariff rates could be filed with the FERC and decisions by the FERC in approving our regulated rates could adversely affect our cash flow. We believe the transportation rates currently charged by our interstate common carrier liquids pipelines are in accordance with the ICA. However, we cannot predict the rates we will be allowed to charge in the future for transportation services by such pipelines.

In October 2009, the FERC approved an uncontested settlement related to a Mid-America Pipeline Company, LLC ("Mid-America") and Seminole rate case before the FERC. The case primarily involved shipper protests of rate increases on Mid-America's Conway North pipeline in FERC Docket Nos. IS05-216-000, IS06-238-000 and IS09-364-000, and challenges to Seminole's interstate rates and certain joint rates between the Seminole Pipeline and Mid-America's Rocky Mountain pipeline in FERC Docket Nos. OR06-5-000 and IS06-520-000. The settlement agreement resolved all matters involving Mid-America's Conway North pipeline at issue in Docket Nos. IS05-216-000, IS06-238-000 and IS09-364-000. Pursuant to the settlement agreement, Mid-America filed new rates for certain propane movements on its Conway North pipeline, which took effect January 1, 2010. Mid-America also paid refunds to propane shippers, as provided by the settlement agreement. In March 2010, Mid-America filed a refund report with the FERC describing the refunds paid. The FERC accepted the refund report in July 2010.

The settlement agreement did not cover the challenges to the Seminole Pipeline and Mid-America Rocky Mountain pipeline rates at issue in Docket Nos. OR06-5-000 and IS06-520-000. In February 2010, the FERC ruled on those issues. The FERC's order also clarified that Mid-America's capacity allocation provisions were not subject to challenge in the case but that the changes to Mid-America's rates contained in FERC Tariff No. 45 were properly at issue. In March 2010, Mid-America and Seminole filed a compliance filing calculating rates consistent with the FERC's February 2010 order. Two parties protested the revised rates. The FERC has not ruled on those protests and we are unable to predict the outcome of that proceeding.

In April 2010, Enterprise TEPPCO filed tariffs in FERC Docket No. IS10-203-000, making certain revisions to its propane inventory policy. A protest was filed by a group of propane shippers (the "Propane Group"). Various other parties later intervened. On May 13, 2010, the FERC accepted Enterprise TEPPCO's tariff subject to the condition that the pipeline submit its prorationing and propane inventory policies to the FERC for review. On May 19, 2010, Enterprise TEPPCO submitted its policies to the FERC as requested. In June 2010, the Propane Group and Texas Liquids Partners, LLC sought rehearing of the FERC's order accepting the tariff. In October 2010, the FERC ruled on the rehearing request and established a hearing to determine whether the propane inventory policy is just and reasonable. In October 2011, the FERC approved a settlement agreement that resolves all matters at issue. Pursuant to the settlement agreement, Enterprise TEPPCO filed a tariff containing a new propane inventory policy, which took effect January 1, 2012. Pursuant to the settlement agreement, Enterprise TEPPCO also calculated certain credits to shippers to offset certain future excess inventory penalties, and certified those calculations to the FERC. Upon certification of the calculations to the FERC, the protests were withdrawn and the proceeding terminated.

In March 2011, Enterprise TEPPCO filed an application in FERC Docket No. OR11-6-000, seeking authorization to charge market-based rates for the interstate transportation of refined petroleum products to the following three delivery locations: Arcadia, Louisiana; Little Rock, Arkansas; and Jonesboro, Arkansas. Protests

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were filed in April 2011 by Lion Oil Company and Chevron Products Company. In October 2011, the FERC set Enterprise TEPPCO's application for hearing before an administrative law judge ("ALJ"). Under the current procedural schedule, the hearing is set to begin August 1, 2012, and the ALJ's decision is due December 21, 2012. We are unable to predict the outcome of that proceeding.

In September 2011, Mid-America filed a tariff in FERC Docket No. IS11-604-000, establishing new rates for interstate transportation on a pipeline segment that moves refined petroleum products from Coffeyville, Kansas to El Dorado, Kansas. Coffeyville Resources Refining & Marketing, LLC protested the rate filing. In October 2011, FERC accepted the tariff subject to refund and hearing. The FERC held the hearing in abeyance pending required settlement judge procedures and settlement discussions are ongoing. In December 2011, Mid-America filed a tariff change in FERC Docket No. IS12-97-000, requiring shippers on the Coffeyville to El Dorado pipeline segment to provide certain information necessary to determine whether shippers' movements are in interstate or intrastate commerce. In January 2012, Coffeyville Resources Refining & Marketing, LLC protested the tariff filing. In January 2012, the FERC accepted the tariff change in FERC Docket No. IS12-97-000, subject to certain modifications. As noted below, Mid-America is also involved in an ongoing matter before the Kansas Corporation Commission (Docket No. 12-MDAP-068-RTS), concerning Mid-America's intrastate rates for certain movements within the state of Kansas, including the intrastate rate for movements on the Coffeyville to El Dorado pipeline segment. We are unable to predict the outcome of these proceedings.

In December 2011, we and Enbridge Inc., which together own the Seaway Crude Pipeline System, filed an application in FERC Docket No. OR12-4-000, seeking authority to charge market-based rates in connection with the planned reversal of the system. Specifically, the application seeks authority to charge market-based rates for the transportation of crude oil at both its proposed Cushing, Oklahoma origin and Gulf Coast area destination markets after the pipeline reverses its current south-to-north direction of service. Protests have been filed by several parties. We are unable to predict the outcome of this proceeding.

In December 2011, Skelly-Belvieu filed a petition for declaratory order in FERC Docket No. OR12-6-000 seeking FERC approval for the overall tariff, rate and priority service structure for a proposed expansion of its existing pipeline system. The only intervenor filed comments in support of the petition for declaratory order. We are unable to predict the outcome of this proceeding.

In December 2011, Dixie Pipeline Company (which changed its name on December 31, 2011, to Dixie Pipeline Company LLC) filed a tariff in FERC Docket No. IS12-88-000 making certain changes to its prorationing rules. Dow Hydrocarbons and Resources LLC protested the tariff filing, and in January 2012, FERC suspended the tariff for the statutory maximum seven months subject to a technical conference. We are unable to predict the outcome of this proceeding.

In January 2012, Dixie Pipeline Company LLC ("Dixie") filed a tariff in FERC Docket No. IS12-120 indicating that as of January 1, 2013, propane shippers will no longer be permitted to inject propane into refinery grade propylene batches as the refinery grade propylene moves by the propane shippers' origin points. Instead, propane shippers will be required to store propane during those periods and make their own arrangements for such storage. Protests were filed by CITGO Petroleum Corporation, Targa Midstream Services LLC, Crosstex Energy Services, L.P., Crosstex NGL Marketing, L.P., and Crosstex Processing Services, LLC. ConocoPhillips Company and Dow Hydrocarbons and Resources LLC moved to intervene. On February 10, 2012, the FERC rejected Dixie's tariff as premature, since the proposed change was not intended to take effect until January 1, 2013.

In February 2012, Enterprise TEPPCO filed a tariff in FERC Docket No. IS12-160-000, establishing new cost-of-service rates for refined petroleum products and NGL movements. As of this report, the deadline for interventions and protests has not yet expired. We are unable to predict the outcome of this proceeding.

The Lou-Tex and Sabine Propylene pipelines are interstate common carrier pipelines regulated under the ICA by the Surface Transportation Board ("STB"). If the STB finds that a carrier's rates are not just and reasonable or are unduly discriminatory or preferential, it may prescribe a reasonable rate. In determining a reasonable rate, the STB will consider, among other factors, the effect of the rate on the volumes transported by that carrier, the carrier's revenue needs and the availability of other economic transportation alternatives.

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The STB does not need to provide rate relief unless shippers lack effective competitive alternatives. If the STB determines that effective competitive alternatives are not available and a pipeline holds market power, then we may be required to show that our rates are reasonable.

Natural Gas Pipelines. Our interstate natural gas pipelines that provide services in interstate commerce are regulated by the FERC under the Natural Gas Act of 1938 (“NGA”). Under the NGA, the rates for service on these interstate facilities must be just and reasonable and not unduly discriminatory. We operate these interstate facilities pursuant to tariffs which set forth rates and terms and conditions of service. These tariffs must be filed with and approved by the FERC pursuant to its regulations and orders. Our tariff rates may be lowered on a prospective basis only by the FERC if it finds, on its own initiative or as a result of challenges to the rates by third parties, that they are unjust, unreasonable or otherwise unlawful. Unless the FERC grants specific authority to charge market-based rates, our rates are derived and charged based on a cost-of-service methodology.

The FERC’s authority over companies that provide natural gas pipeline transportation or storage services in interstate commerce also extends to: (i) the construction and operation of certain new facilities; (ii) the acquisition, extension, disposition or abandonment of such facilities; (iii) the maintenance of accounts and records; (iv) the initiation, extension and termination of regulated services; and (v) various other matters. The FERC’s rules require interstate pipelines and their affiliates to adhere to Standards of Conduct that, among other things, require that transportation and marketing employees function independently of each other. The Energy Policy Act of 2005 amended the NGA to add an anti-manipulation provision. Pursuant to that act, the FERC established rules prohibiting energy market manipulation. A violation of these rules may subject us to civil penalties, disgorgement of unjust profits, or appropriate non-monetary remedies imposed by the FERC. In addition, the Energy Policy Act of 2005 amended the NGA and the Natural Gas Policy Act of 1978 (“NGPA”) to increase civil and criminal penalties for any violation of the NGA, NGPA and any rules, regulations or orders of the FERC up to $1 million per day per violation.

In March 2009, High Island Offshore System, L.L.C. (“HIOS LLC,” which owns HIOS) filed with the FERC a general rate change application under Section 4 of the NGA proposing, among other things, an increase in HIOS’ firm and interruptible transportation rates. Pursuant to the FERC’s order issued in April 2009, the rates went into effect, subject to refund, in October 2009. In March 2009, HIOS LLC also filed a petition requesting the FERC to declare that all facilities at and upstream of the High Island Area (“HIA”) Block 264 platform perform a non-jurisdictional gathering service. In September 2009, the FERC issued an order generally approving the petition. Finally, in January 2010, as a result of a platform fire at HIA Block 264, HIOS LLC filed an application seeking approval to remove three compressor units on the platform and to reduce the certificated capacity of HIOS. In April 2011, the FERC approved a settlement agreement resolving all outstanding issues in these three FERC proceedings, other than one “reserved issue” related to the rate proceeding that remains pending as of this report. We are unable to predict the outcome of that reserved issue.

Offshore Pipelines. Our offshore natural gas gathering pipelines and crude oil pipeline systems are subject to federal regulation under the Outer Continental Shelf Lands Act (“OCSLA”), which requires that all pipelines operating on or across the outer continental shelf provide nondiscriminatory transportation service.

Intrastate Pipelines

Liquids Pipelines. Certain of our pipeline systems operate within a single state and provide intrastate pipeline transportation services. These pipeline systems are subject to various regulations and statutes mandated by state regulatory authorities. Although the applicable state statutes and regulations vary widely, they generally require that intrastate pipelines publish tariffs setting forth all rates, rules and regulations applying to intrastate service, and generally require that pipeline rates and practices be reasonable and nondiscriminatory. Shippers may challenge our intrastate tariff rates and practices on our pipelines. Our intrastate liquids pipelines are subject to regulation in many states, including Alabama, Colorado, Illinois, Kansas, Louisiana, Minnesota, Mississippi, New Mexico, Oklahoma and Texas.

As noted above, Mid-America is currently involved in a rate case before the Kansas Corporation Commission (Docket No. 12-MDAP-068-RTS), involving Mid-America's intrastate rates for certain movements within the state of Kansas. We are unable to predict the outcome of that proceeding.

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Natural Gas Pipelines. Our intrastate natural gas pipelines are subject to regulation in many states, including Colorado, Louisiana, New Mexico, Texas and Wyoming. Certain of our intrastate natural gas pipelines are also subject to limited regulation by the FERC under the NGPA because they provide transportation and storage service pursuant to Section 311 of the NGPA and Part 284 of the FERC's regulations. Under Section 311 of the NGPA, an intrastate pipeline may transport gas on behalf of an interstate pipeline company or any local distribution company served by an interstate pipeline without becoming subject to the FERC's jurisdiction under the NGA. However, such a pipeline is required to provide these services on an open and nondiscriminatory basis, to post certain transactional information on its website, and to make certain rate and other filings and reports in compliance with the FERC's regulations. The rates for Section 311 services may be established by the FERC or the respective state agency, but such rates may not exceed a fair and equitable rate. The Texas Railroad Commission has the authority to regulate the rates and terms of service for our intrastate transportation service in Texas.

Under the terms of an uncontested settlement approved by the FERC in December 2010 in the last Section 311 rate proceeding for Enterprise Texas Pipeline LLC, we are required to justify the applicable settlement rates or establish new rates for NGPA Section 311 service on or before March 31, 2015.

Under the terms of an uncontested settlement that was approved by the FERC in July 2010 in the last Section 311 rate proceedings for the Acadian Gas System and Cypress pipelines, the pipelines are required to justify the applicable settlement rates or establish new rates for NGPA Section 311 service on or before July 13, 2014.

In September 2011, Acadian Gas LLC ("Acadian Gas") filed a petition in FERC Docket No. PR11-129-000, seeking approval for new rates for NGPA Section 311 service on its new Haynesville Extension pipeline. As part of the petition for rate approval, Acadian Gas also filed changes to the Statement of Operating Conditions to reflect the new service. One party protested the changes to the Statement of Operating Conditions, but not the proposed new rates. We are unable to predict the outcome of that proceeding.

Natural Gas Sales

We are engaged in natural gas marketing activities. The resale of natural gas in interstate commerce is subject to FERC jurisdiction. However, under current federal rules the price at which we sell natural gas is not regulated insofar as the interstate market is concerned and, for the most part, is not subject to state regulation. Our affiliates that engage in natural gas marketing may be considered marketing affiliates of certain of our interstate natural gas pipelines. The FERC's rules require pipelines and their marketing affiliates who sell natural gas in interstate commerce subject to the FERC's jurisdiction to adhere to standards of conduct that, among other things, require that their transportation and marketing employees function independently of each other. Pursuant to the Energy Policy Act of 2005, the FERC has also established rules prohibiting energy market manipulation. A violation of these rules by us or our employees or agents may subject us to civil penalties, suspension or loss of authorization to perform such sales, disgorgement of unjust profits or other appropriate non-monetary remedies imposed by the FERC. The Federal Trade Commission and the Commodity Futures Trading Commission also have issued rules and regulations prohibiting market manipulation.

The FERC is continually proposing and implementing new rules and regulations affecting segments of the natural gas industry. For example, the FERC has adopted market monitoring and annual reporting regulations which are applicable to many intrastate pipelines and other entities that are otherwise not subject to the FERC's NGA jurisdiction. The FERC also has established rules requiring the annual reporting of gas sales information, in order to increase transparency in natural gas markets. We cannot predict the ultimate impact of these regulatory changes on our natural gas marketing activities; however, we believe that any new regulations will also be applied to other natural gas marketers with whom we compete.

Marine Operations

Maritime Law. The operation of tow boats, barges and marine equipment create maritime obligations involving property, personnel and cargo under General Maritime Law. These obligations can create risks which are varied and include, among other things, the risk of collision and allision, which may precipitate claims for personal injury, cargo, contract, pollution, third party claims and property damages to vessels and facilities. Routine towage

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operations can also create risk of personal injury under the Jones Act and General Maritime Law, cargo claims involving the quality of a product and delivery, terminal claims, contractual claims and regulatory issues.

Jones Act. We are subject to the Jones Act and other federal laws that restrict maritime transportation between points in the U.S. to vessels built and registered in the U.S. and owned and manned by U.S. citizens. We are responsible for monitoring the ownership of our common units and other partnership interests. If we do not comply with these restrictions, we would be prohibited from operating our vessels in U.S. coastwise trade, and under certain circumstances we would be deemed to have undertaken an unapproved foreign transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of the vessels.

In addition, the USCG and American Bureau of Shipping (“ABS”) maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for U.S.-flag operators than for owners of vessels registered under foreign flags of convenience. The Jones Act and General Maritime Law also provide damage remedies for crew members injured in the service of the vessel arising from employer negligence or vessel unseaworthiness. In certain circumstances, a Jones Act seaman can have dual employers under the borrowed servant doctrine.

Merchant Marine Act of 1936. The Merchant Marine Act of 1936 is a federal law that provides that, upon proclamation by the U.S. President of a national emergency or a threat to the national security, the U.S. Secretary of Transportation (the “Transportation Secretary”) may requisition or purchase any vessel or other watercraft owned by U.S. citizens (including us, provided that we are considered a U.S. citizen for this purpose). If one of our tow boats or barges were purchased or requisitioned by the U.S. government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, if one of our tow boats is requisitioned or purchased and its associated barge or barges are left idle, we would not be entitled to receive any compensation for the lost revenues resulting from the idled barges. We also would not be entitled to be compensated for any consequential damages we suffer as a result of the requisition or purchase of any of our tow boats or barges.

Environmental and Safety Matters

The following sections describe the general impact of environmental and safety matters on our business. Additional information regarding environmental and safety risks are described under Item 1A of this annual report.

Our operations are subject to various environmental and safety requirements and potential liabilities under extensive federal, state and local laws and regulations. These include, without limitation: the Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”); the Resource Conservation and Recovery Act (“RCRA”); the Federal Clean Air Act (“CAA”); the Federal Water Pollution Control Act of 1972, renamed and amended as the Clean Water Act (“CWA”); the Oil Pollution Act of 1990 (“OPA”); the Federal Occupational Safety and Health Act, as amended (“OSHA”); the Emergency Planning and Community Right to Know Act; and comparable or analogous state and local laws and regulations. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals, with respect to air emissions, water quality, wastewater discharges and solid and hazardous waste management. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could have a material adverse effect on our financial position, results of operations and cash flows. If a leak, spill or release of hazardous substances occurs at any facilities that we own, operate or otherwise use, or where we send materials for treatment or disposal, we could be held liable for all resulting liabilities, including investigation, remedial and clean-up costs. Likewise, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination. Any or all of this could have a material adverse effect on our financial position, results of operations and cash flows.

We believe our operations are in material compliance with applicable environmental and safety laws and regulations and that compliance with existing environmental and safety laws and regulations are not expected to have a material adverse effect on our financial position, results of operations and cash flows. Environmental and safety laws and regulations are subject to change. The trend in environmental regulation has been to place more restrictions and limitations on activities that may be perceived to affect the environment, and thus there can be no

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assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our financial position, results of operations and cash flows.

On occasion, we are assessed monetary sanctions by governmental authorities related to administrative or judicial proceedings involving environmental matters. See Item 3 of this annual report for a discussion of such matters where the amount of monetary sanctions sought is in excess of $100,000.

Air Emissions

Our operations are associated with emissions of air pollution and are subject to the CAA and comparable state laws and regulations including state implementation plans. These laws and regulations regulate emissions of air pollutants from various industrial sources, including certain of our facilities, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions.

Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions, as well as to comply with pending regulations (e.g., Oil and Gas New Source Performance Standards). We believe, however, that such requirements will not have a material adverse effect on our operations, and the requirements are not expected to be any more burdensome to us than any other similarly situated company.

Climate Change Regulations

Responding to scientific studies suggesting that emissions of gases, commonly referred to as “greenhouse gases,” including gases associated with oil and gas production such as carbon dioxide, methane and nitrous oxide among others, may be contributing to a warming of the earth’s atmosphere and other adverse environmental effects, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases. The U.S. Environmental Protection Agency (“EPA”) has also taken action under the CAA to regulate greenhouse gas emissions. In addition, some states, including states in which our facilities or operations are located, have taken or proposed legal measures to reduce emissions of greenhouse gases.

In the 111th Congress, numerous legislative measures were introduced that would have imposed restrictions or costs on greenhouse gas emissions, including from the oil and gas industry. Conversely, the 112th Congress, which convened in January 2011, slowed the federal efforts to implement greenhouse gas regulations, which resulted in certain states and regional partnerships taking the initiative. While the state efforts seem less burdensome, any such legislation may have the potential to affect our business, customers or the energy sector generally.

On an international level, the U.S. has been involved in negotiations regarding greenhouse gas reductions under the United Nations Framework Convention on Climate Change (“UNFCCC”). Other nations have already agreed to regulate emissions of greenhouse gases, pursuant to the UNFCCC and a subsidiary agreement known as the “Kyoto Protocol,” an international treaty pursuant to which participating countries have agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. The U.S. is a party to the UNFCCC but did not ratify the Kyoto Protocol. Such negotiations have not thus far resulted in substantive changes that would affect domestic industrial sources in the U.S. and it is uncertain whether an international agreement will be reached or what the terms of any such agreement would be.

Following the U.S. Supreme Court's decision in Massachusetts, et al. v. EPA, 549 U.S. 497 (2007), finding that greenhouse gases fall within the CAA definition of "air pollutant," the EPA determined that greenhouse gases

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from certain sources "endanger" public health or welfare. As a result, the EPA has taken the position that existing CAA provisions require an assessment of greenhouse gas emissions within the permitting process for certain large new or modified stationary sources under the EPA's Prevention of Significant Deterioration ("PSD") and Title V permit programs beginning in 2011. Facilities triggering permit requirements may be required to reduce greenhouse gas emissions consistent with "best available control technology" standards if deemed to be cost-effective. Such changes will also affect state air permitting programs in states that administer the CAA under a delegation of authority, including states in which we have operations. Additionally, in November 2010, the EPA finalized rules expanding its Mandatory Greenhouse Gas Reporting Rule, originally promulgated in October 2009, to be applicable to the oil and natural gas industry. The expansion requires annual, on-site monitoring and additional inventory and reporting of greenhouse gas emissions and affects many of our existing operations and must be considered for future operations. Although subject to legal challenge, the EPA rules promulgated thus far are currently final and effective, and will remain so unless the regulations are overturned by a court ruling, or Congress adopts legislation altering the EPA's regulatory authority.

A number of states, individually or in regional cooperation, have also imposed restrictions on greenhouse gas emissions under various policies and approaches, including establishing a cap on emissions, requiring efficiency measures, or providing incentives for pollution reduction, use of renewable energy, or use of fuels with lower carbon content. These initiatives include the following:

§ Ten states in the Northeast and Mid-Atlantic region signed a compact and have implemented rules to limit carbon dioxide emissions from power plants under the Regional Greenhouse Gas Initiative ("RGGI"), which requires electric generating facilities to purchase emissions allowances corresponding to their respective emissions under a cap-and-trade system. RGGI started its second compliance period (from 2012-2014) under the cap-and-trade program and is currently conducting a state by state evaluation of the efficiency, impacts and economic feasibility of the program.

§ The California Air Resources Board ("CARB") has issued a series of rules under that state's Global Warming Solutions Act, including restrictions on greenhouse gas emissions from industrial sources and regulating the carbon content of fuels. In December 2010, the CARB approved a resolution to develop a multi-year, comprehensive program designed to reduce greenhouse gas emissions to be in place by January 2012. On October 20, 2011, the requirements of this program were finalized and registration for covered entities must be completed by January 31, 2012.

§ In November 2010, the New Mexico Environmental Improvement Board adopted new regulations pursuant to state law establishing a greenhouse gas cap-and-trade system to be implemented by the New Mexico Environment Department. However, the cap-and-trade program was repealed in February 2012.

There have also been several court cases implicating greenhouse gas emissions and climate change issues that could have established a regulatory precedent. First, in September 2009, the U.S. Court of Appeals for the Second Circuit issued its decision in Connecticut v. American Electric Power Co., 582 F.3d 309 (2d Cir. Sept. 21, 2009). With this case, the Second Circuit held that certain state and private plaintiffs could sue energy companies on the asserted basis that greenhouse gas emissions created a "public nuisance." However, in June 2011, the U.S. Supreme Court held that the CAA and EPA actions displace the right to seek abatement of emissions under federal common law but left open whether state law tort actions were pre-empted. Second, a three-judge panel of the U.S. Court of Appeals for the Fifth Circuit initially upheld claims in Comer v. Murphy Oil USA, 585 F.3d 855 (5th Cir. Oct. 16, 2009), by property owners who suffered casualty losses in Hurricane Katrina alleging that certain energy, fossil fuel and chemical industries emitted greenhouse gases that contributed to global warming and ultimately exacerbated property damage from the hurricane. The Fifth Circuit subsequently vacated the panel decision and, because of a procedural issue, was unable to review the merits of the claims. In May 2011, the case was refiled in the Southern District of Mississippi with a focus on state law causes of action. A similar case, Native Village of Kivalina v. ExxonMobil Corp., 663 F. Supp. 2d 863 (N.D. Cal. Sept. 30, 2009), dismissed similar claims for lack of subject matter jurisdiction, and this decision was appealed to the U.S. Court of Appeals for the Ninth Circuit where oral argument was heard in November 2011. While these cases expose other significant emission sources of greenhouse gases to similar litigation risk, there seems to be limited support for this type of legal action.

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These federal, regional and state measures generally apply to industrial sources, including facilities in the oil and gas sector, and could increase the operating and compliance costs of our pipelines, natural gas processing plants, fractionation plants and other facilities. These regulations could also adversely affect market demand or pricing for our products or products served by our midstream infrastructure, by affecting the price of, or reducing the demand for, fossil fuels or providing competitive advantages to competing fuels and energy sources. The potential increase in the costs of our operations could include costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions, or administer and manage a greenhouse gas emissions program. While we may be able to include some or all of such increased costs in the rates charged by our pipelines or other facilities, such recovery of costs is uncertain and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC and the provisions of any final regulations. In addition, changes in regulatory policies that result in a reduction in the demand for hydrocarbon products that are deemed to contribute to greenhouse gases, or restrictions on their use, may reduce volumes available to us for processing, transportation, marketing and storage.

Physical Impacts of Climate Change

There is considerable debate over global warming and the environmental effects of greenhouse gas emissions and associated consequences affecting global climate, oceans and ecosystems. As a commercial enterprise, we are not in a position to validate or repudiate the existence of global warming or various aspects of the scientific debate. However, if global warming is occurring, it could have an impact on our operations. For example, our facilities that are located in low lying areas such as the coastal regions of Louisiana and Texas may be at increased risk due to flooding, rising sea levels, or disruption of operations from more frequent and severe weather events. Facilities in areas with limited water availability may be impacted if droughts become more frequent or severe. Changes in climate or weather may hinder exploration and production activities or increase the cost of production of oil and gas resources and consequently affect the volume of hydrocarbon products entering our system. Changes in climate or weather may also affect consumer demand for energy or alter the overall energy mix. However, we are not in a position to predict the precise effects of global warming. We are providing this disclosure based on publicly available information on the matter.

Water

The CWA and comparable state laws impose strict controls on the discharge of oil and its derivatives into regulated waters. The CWA provides penalties for any discharges of petroleum products in reportable quantities and imposes substantial potential liability for the costs of removing petroleum or other hazardous substances. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of a release of petroleum or its derivatives in navigable waters or into groundwater. Spill prevention control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent a petroleum tank release from impacting regulated waters. The EPA has also adopted regulations that require us to have permits in order to discharge certain storm water run-off. Storm water discharge permits may also be required by certain states in which we operate and may impose certain monitoring and other requirements. The CWA further prohibit discharges of dredged and fill material in wetlands and other waters of the U.S. unless authorized by an appropriately issued permit. We believe that our costs of compliance with these CWA requirements will not have a material adverse effect on our financial position, results of operations and cash flows.

The primary federal law for oil spill liability is the OPA, which addresses three principal areas of oil pollution: prevention, containment and clean-up and liability. The OPA applies to vessels, offshore platforms and onshore facilities, including terminals, pipelines and transfer facilities. In order to handle, store or transport oil above certain thresholds, shore facilities are required to file oil spill response plans with the USCG, the DOT's Office of Pipeline Safety ("OPS") or the EPA, as appropriate. Numerous states have enacted laws similar to the OPA. Under the OPA and similar state laws, responsible parties for a regulated facility from which oil is discharged may be liable for removal costs and natural resource damages. Any unpermitted release of petroleum or other pollutants from our pipelines or facilities could result in fines or penalties as well as significant remedial obligations.

Contamination resulting from spills or releases of petroleum products is an inherent risk within the petroleum pipeline industry. To the extent that groundwater contamination requiring remediation exists along our pipeline systems or other facilities as a result of past operations, we believe any such contamination could be

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controlled or remedied without having a material adverse effect on our financial position, results of operations and cash flows, but such costs are site specific, and there is no assurance that the effect will not be material in the aggregate.

Solid Waste

In our normal operations, we generate hazardous and non-hazardous solid wastes that are subject to requirements of the federal RCRA and comparable state statutes, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and solid waste. We also utilize waste minimization and recycling processes to reduce the volumes of our waste.

Endangered Species

The federal Endangered Species Act, as amended, and comparable state laws, may restrict activities that affect endangered and threatened species or their habitats. Some of our current or future planned facilities may be located in areas that are designated as a habitat for endangered or threatened species, and if so may limit or impose increased costs on facility construction or operation. In addition, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Environmental Remediation

CERCLA, also known as “Superfund,” imposes liability, often without regard to fault or the legality of the original act, on certain classes of persons who contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of a facility where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at a facility. Under CERCLA, responsible parties may be subject to 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. CERCLA and RCRA also authorize the EPA and, in some instances, third parties to take actions in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. 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, our pipeline systems and other facilities generate wastes that may fall within CERCLA’s definition of a “hazardous substance” or be subject to CERCLA and RCRA remediation requirements. It is possible that we could incur liability for remediation or reimbursement of remediation costs under CERCLA or RCRA for remediation at sites we currently own or operate, whether as a result of our or our predecessors’ operations, at sites that we previously owned or operated, or at disposal facilities previously used by us, even if such disposal was legal at the time it was undertaken.

In the fourth quarter of 2011, certain of our subsidiaries were named by the EPA as potentially responsible parties in connection with the U.S. Oil Recovery Superfund Site located in Pasadena, Texas. We believe that the eventual resolution of these matters will result in penalties and other costs exceeding $0.1 million.

Pipeline Safety Matters

We are subject to regulation by the DOT under the Accountable Pipeline and Safety Partnership Act of 1996, sometimes referred to as the Hazardous Liquid Pipeline Safety Act (“HLPSA”), and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. The HLPSA covers petroleum and petroleum products and requires any entity that owns or operates pipeline facilities to

(i) comply with such regulations, (ii) permit access to and copying of records, (iii) file certain reports and (iv) provide information as required by the Transportation Secretary. In addition, our natural gas pipeline assets are subject to the DOT's OPS under the Natural Gas Pipeline Safety Act ("NGPSA"). We believe we are in material compliance with these DOT regulations.

We are also subject to the DOT regulation requiring qualification of pipeline personnel. The regulation requires pipeline operators to develop and maintain a written qualification program for individuals performing

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covered tasks on pipeline facilities. The intent of this regulation is to ensure a qualified work force and to reduce the probability and consequence of incidents caused by human error. The regulation establishes qualification requirements for individuals performing covered tasks. In addition, we are subject to the DOT regulation that requires pipeline operators to institute certain control room procedures. These procedures were implemented in October 2011 and we believe we are in material compliance with these DOT regulations.

In addition, we are subject to the DOT pipeline integrity management regulations in 49 CFR Parts 192 and 195, which specify how companies should assess, evaluate, validate and maintain the integrity of pipeline segments that, in the event of a release, could impact High Consequence Areas ("HCAs"). HCAs are defined to include populated areas, unusually sensitive environmental areas and commercially navigable waterways. The regulation requires the development and implementation of an integrity management program that utilizes internal pipeline inspection, pressure testing or other equally effective means to assess the integrity of HCA pipeline segments. The regulation also requires periodic review of HCA pipeline segments to ensure that adequate preventative and mitigative measures exist and that companies take prompt action to address integrity issues raised by the assessment and analysis. In June 2008, the DOT extended its pipeline safety regulations, including integrity management requirements, to certain rural onshore hazardous liquid gathering lines and certain rural onshore low-stress hazardous liquid pipelines within a one-half mile buffer zone around "unusually sensitive areas." In May 2011, the DOT amended the pipeline safety regulations to apply the regulations to rural low-stress hazardous liquid pipelines that are not covered by the regulations in 49 CFR Part 195. Therefore, effective October 1, 2011, the pipeline safety regulations apply to all small-diameter (less than 8 5/8 inches) rural low-stress pipelines located within a one-half mile buffer zone of an unusually sensitive area and to all rural low-stress pipelines of any diameter located outside such one-half mile buffer zones. We have identified our HCA pipeline segments and developed an appropriate integrity management program.

The DOT also issued an Advance Notice of Proposed Rulemaking in October 2010 in which it is considering whether to remove or modify regulatory exemptions that currently exist in the pipeline safety regulations for the gathering of hazardous liquids by pipelines in rural areas. The comment period for this notice ended in February 2011; however, we cannot predict the ultimate impact of the proposed changes on our operations at this time.

In January 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 into law. This legislation provides stronger oversight of the nation's pipelines, increases the penalties for violations of pipeline safety rules, and complements the DOT's other initiatives. This legislation increases the maximum fine for the most serious pipeline safety violations involving deaths, injuries or major environmental harm from $1 million to $2 million. In addition, the legislation improves pipeline transportation and safety by: (i) improving pipeline damage prevention measures and cracking down on third party pipeline damage; (ii) allowing the Transportation Secretary to require automatic and remote-controlled shut-off valves on new pipelines; (iii) requiring the Transportation Secretary to evaluate the effectiveness of expanding pipeline integrity management and leak detection requirements; (iv) improving the way the DOT and pipeline operators provide information to the public and emergency responders; and (v) reforming the process by which pipeline operators notify federal, state and local officials of pipeline accidents.

Risk Management Plans

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

Other Safety Matters

Certain of our facilities are also subject to the requirements of the federal OSHA and comparable state statutes. We believe we are in material compliance with OSHA and state requirements, including general industry standards, record keeping requirements and monitoring of occupational exposures.

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Certain of our facilities are subject to OSHA PSM regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves certain flammable liquid or gas. We believe we are in material compliance with the OSHA PSM regulations.

The OSHA hazard communication standard, the community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to federal, state and local governmental authorities and local citizens upon request. These laws and provisions of CERCLA require reporting of spills and releases of hazardous chemicals in certain situations.

Employees

Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers. As of December 31, 2011, there were approximately 6,900 EPCO personnel who spend all or a portion of their time engaged in our business. Approximately 6,600 of these individuals devote substantially all of their time to our affairs. For additional information regarding the ASA, see "—EPCO Administrative Services Agreement" under Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Available Information

As a publicly traded partnership, we electronically file certain documents with the SEC. We file annual reports on Form 10-K; quarterly reports on Form 10-Q; and current reports on Form 8-K (as appropriate); along with any related amendments and supplements thereto. Occasionally, we may also file registration statements and related documents in connection with equity or debt offerings. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information regarding the Public Reference Room by calling the SEC at (800) SEC-0330. In addition, the SEC maintains an Internet website at www.sec.gov that contains reports and other information regarding registrants that file electronically with the SEC.

We provide electronic access to our periodic and current reports on our Internet website, www.enterpriseproducts.com. These reports are available as soon as reasonably practicable after we electronically file such materials with, or furnish such materials to, the SEC. You may also contact our Investor Relations department at (866) 230-0745 for paper copies of these reports free of charge. We do not intend to incorporate the information on our website into this annual report.

Item 1A. Risk Factors.

An investment in our common units or debt securities involves certain risks. If any of the following key risks were to occur, it could have a material adverse effect on our financial position, results of operations and cash flows, as well as our ability to maintain or increase distribution levels. In any such circumstance and others described below, the trading price of our securities could decline and you could lose part or all of your investment.

Risks Relating to Our Business

Our standalone operating cash flow is derived primarily from cash distributions we receive from EPO.

The quarterly cash distributions paid by Enterprise Products Partners L.P. are derived from the cash distributions it receives from EPO. The amount of cash EPO can distribute principally depends upon the cash flow generated from its operations, which will fluctuate from quarter-to-quarter based on, among other things, the: (i) volume of hydrocarbon products transported on its gathering and transmission pipelines; (ii) throughput volumes in its processing and treating operations; (iii) fees charged and the margins realized for its various storage, terminaling, processing and transportation services; (iv) price of natural gas, crude oil and NGLs; (v) relationships among natural gas, crude oil and NGL prices, including differentials between regional markets; (vi) fluctuations in its working

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capital needs; (vii) level of its operating costs; (viii) prevailing economic conditions; and (ix) level of competition encountered by its businesses. In addition, the actual amount of cash EPO will have available for distribution will depend on factors such as: (i) the level of sustaining capital expenditures incurred; (ii) its cash outlays for expansion (or growth) capital projects and acquisitions; and (iii) its debt service requirements and restrictive covenants. Because of these factors, we may not have sufficient available cash each quarter to continue paying distributions at our current levels.

Furthermore, the amount of cash we have available for distribution is not solely a function of profitability, which will be affected by non-cash items such as depreciation, amortization and provisions for asset impairments. Our cash flows are also impacted by borrowings under credit agreements and similar arrangements. As a result, we may be able to make cash distributions during periods when we record losses and may not be able to make cash distributions during periods when we record net income. An inability on our part to pay cash distributions to partners at our current levels or projected levels could have an adverse effect on our financial position, results of operations and cash flows.

Changes in demand for and production of hydrocarbon products could have a material adverse effect on our financial position, results of operations and cash flows.

We operate predominantly in the midstream energy industry, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs, crude oil and refined products. As such, changes in the prices of hydrocarbon products and in the relative price levels among hydrocarbon products could have a material adverse effect on our financial position, results of operations and cash flows. Changes in prices may impact demand for hydrocarbon products, which in turn may impact production, demand and the volumes of products for which we provide services. We may also incur credit and price risk to the extent counterparties do not fulfill their obligations to us in connection with our marketing of natural gas, NGLs, propylene, refined products and/or crude oil.

Historically, the price of natural gas has been extremely volatile, and we expect this volatility to continue. The New York Mercantile Exchange ("NYMEX") daily settlement price for natural gas for the prompt month contract in 2010 ranged from a high of $6.01 per MMBtu to a low of $3.29 per MMBtu. In 2011, the same index ranged from a high of $4.85 per MMBtu to a low of $2.99 per MMBtu.

Generally, prices of hydrocarbon products are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of other uncontrollable factors, such as: (i) the level of domestic production and consumer product demand; (ii) the availability of imported oil and natural gas and actions taken by foreign oil and natural gas producing nations; (iii) the availability of transportation systems with adequate capacity; (iv) the availability of competitive fuels; (v) fluctuating and seasonal demand for oil, natural gas, NGLs and other hydrocarbon products; (vi) the impact of conservation efforts; (vii) governmental regulation and taxation of production; and (viii) prevailing economic conditions.

We are exposed to natural gas and NGL commodity price risk under certain of our natural gas processing and gathering and NGL fractionation contracts that provide for our fees to be calculated based on a regional natural gas or NGL price index or to be paid in-kind by taking title to natural gas or NGLs. A decrease in natural gas and NGL prices can result in lower margins from these contracts, which could have a material adverse effect on our financial position, results of operations and cash flows. Volatility in commodity prices may also have an impact on many of our customers, which in turn could have a negative impact on their ability to fulfill their obligations to us.

The crude oil, natural gas and NGLs currently transported, gathered or processed at our facilities originate from existing domestic and international resource basins, which naturally deplete over time. To offset this natural decline, our facilities will need access to production from newly discovered properties. Many economic and business factors beyond our control can adversely affect the decision by producers to explore for and develop new reserves. These factors could include relatively low oil and natural gas prices, cost and availability of equipment and labor, regulatory changes, capital budget limitations, the lack of available capital or the probability of success in finding hydrocarbons. A decrease in exploration and development activities in the regions where our facilities and other energy logistic assets are located could result in a decrease in volumes to our natural gas processing plants, natural gas, crude oil and NGL pipelines, NGL fractionators and offshore platforms, which could have a material adverse effect on our financial position, results of operations and cash flows.

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A decrease in demand for NGL products by the petrochemical, refining or heating industries could have a material adverse effect on our financial position, results of operations and cash flows.

Decreases in demand may be caused by prevailing economic conditions, reduced demand by consumers for the end products made with NGL products, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, government regulations affecting prices and production levels of natural gas, the content of motor gasoline, or other reasons. For example:

§ Ethane is primarily used in the petrochemical industry as feedstock in the production of ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. If natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls (and, therefore, the demand for ethane decreases), it may be more profitable for natural gas producers to leave the ethane in a mixed natural gas stream to be burned as fuel than to extract it for sale as an ethylene feedstock.

§ The demand for propane as a heating fuel is significantly affected by weather conditions. Unusually warm winters could cause the demand for propane to decline significantly and could cause a significant decline in the volumes of propane that we transport.

§ A reduction in demand for motor gasoline additives may reduce demand for isobutane, which could adversely impact the price of isobutane and reduce our operating margin from selling isobutane.

§ Propylene is sold to petrochemical companies for a variety of uses, principally for the production of polypropylene. Propylene is subject to rapid and material price fluctuations. Any downturn in the domestic or international economy could cause reduced demand for, and an oversupply of propylene, which could cause a reduction in the volumes of propylene that we sell and transport.

We face competition from third parties in our midstream energy businesses.

Even if crude oil and natural gas reserves exist in the areas served by our assets, we may not be chosen by producers in these areas to gather, transport, process, fractionate, store or otherwise handle the hydrocarbons extracted. We compete with other companies, including producers of oil and natural gas, for any such production on the basis of many factors, including but not limited to geographic proximity to the production, costs of connection, available capacity, rates and access to markets.

Our refined products, NGL and marine transportation businesses may compete with other pipelines and marine transportation companies in the areas they serve. We also compete with railroads and third party trucking operations in certain of the areas we serve. Competitive pressures may adversely affect our tariff rates or volumes shipped. Also, substantial new construction of inland marine vessels could create an oversupply and intensify competition for our marine transportation business.

The crude oil gathering and marketing business can be characterized by thin operating margins and intense competition for supplies of crude oil at the wellhead. A decline in domestic crude oil production could intensify this competition among gatherers and marketers. Our crude oil transportation business competes with common carriers and proprietary pipelines owned and operated by major oil companies, large independent pipeline companies, financial institutions with trading platforms and other companies in the areas where such pipeline systems deliver crude oil.

In our natural gas gathering business, we encounter competition in obtaining contracts to gather natural gas supplies, particularly new supplies. Competition in natural gas gathering is based in large part on reputation, efficiency, system reliability, gathering system capacity and pricing arrangements. Our key competitors in the gas gathering segment include independent gas gatherers and major integrated energy companies. Alternate gathering facilities are available to producers we serve, and those producers may also elect to construct proprietary gas gathering systems.

A significant increase in competition in the midstream energy industry could have a material adverse effect on our financial position, results of operations and cash flows.

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Our debt level may limit our future financial and operating flexibility.

As of December 31, 2011, we had approximately $12.95 billion in principal amount of consolidated senior long-term debt outstanding and approximately $1.53 billion in principal amount of junior subordinated debt outstanding. The amount of our future debt could have significant effects on our operations, including, among other things:

§ a substantial portion of our cash flow could be dedicated to the payment of principal and interest on our future debt and may not be available for other purposes, including the payment of distributions on our common units and capital expenditures;

§ credit rating agencies may take a negative view of our consolidated debt level;

§ covenants contained in our existing and future credit and debt agreements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;

§ our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

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

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

Our public debt indentures currently do not limit the amount of future indebtedness that we can incur, assume or guarantee. Although our credit agreements restrict our ability to incur additional debt above certain levels, any debt we may incur in compliance with these restrictions may still be substantial. For information regarding our long-term debt, see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our credit agreements and each of the indentures related to our public debt instruments include traditional financial covenants and other restrictions. For example, we are prohibited from making distributions to our partners if such distributions would cause an event of default or otherwise violate a covenant under our credit agreements. A breach of any of these restrictions by us could permit our lenders or noteholders, as applicable, to declare all amounts outstanding under these debt agreements to be immediately due and payable and, in the case of our credit agreements, to terminate all commitments to extend further credit.

Our ability to access capital markets to raise capital on favorable terms could be affected by our debt level, when such debt matures, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, we could experience an increase in our borrowing costs, difficulty assessing capital markets and/or a reduction in the market price of our securities. Such a development could adversely affect our ability to obtain financing for working capital, capital expenditures or acquisitions, or to refinance existing indebtedness. If we are unable to access the capital markets on favorable terms in the future, we might be forced to seek extensions for some of our short-term debt obligations or to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected levels.

We may not be able to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for investment opportunities.

Our growth strategy contemplates the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses that enhance our ability to compete effectively and to diversify our asset portfolio, thereby providing us with more stable cash flows. We consider and pursue potential joint ventures, standalone projects and other transactions that we believe may present opportunities to expand our business, increase our market position and realize operational synergies.

We will require substantial new capital to finance the future development and acquisition of assets and businesses. For example, for the year ended December 31, 2011, we spent $3.55 billion on growth capital projects, of which approximately $867 million was for the Haynesville Extension and $1.59 billion for Eagle Ford Shale projects. Based on information currently available, we estimate our consolidated capital spending for 2012 will approximate $3.8 billion, which includes estimated expenditures of $3.5 billion for growth capital projects and $315 million for sustaining capital expenditures. Any limitations on our access to capital may impair our ability to execute this growth strategy. If our cost of debt or equity capital becomes too expensive, our ability to develop or acquire accretive assets will be limited. We also may not be able to raise the necessary funds on satisfactory terms, if at all.

Any future tightening of the credit markets may have a material adverse effect on us by, among other things, decreasing our ability to finance growth capital projects or business acquisitions on favorable terms and by the imposition of increasingly restrictive borrowing covenants. In addition, the distribution yields of any new equity we may issue may be higher than historical levels, making additional equity issuances more expensive.

We also may compete with third parties in the acquisition of energy infrastructure assets that complement our existing asset base. Increased competition for a limited pool of assets could result in our losing to other bidders more often than in the past or acquiring assets at less attractive prices. Either occurrence could limit our ability to fully execute our growth strategy. Our inability to execute our growth strategy may materially adversely affect our ability to maintain or pay higher cash distributions in the future.

Our variable-rate debt and future maturities of fixed-rate, long-term debt make us vulnerable to increases in interest rates, which could have a material adverse effect on our financial position, results of operation and cash flows.

As of December 31, 2011, we had $14.48 billion in principal amount of consolidated long-term debt outstanding, including current maturities thereof. Of this amount, approximately $1.1 billion, or 7.6%, was subject to variable interest rates, either as long-term variable-rate debt obligations or as long-term fixed-rate debt converted to variable rates through the use of interest rate swaps. As of the date of this report, we have $500.0 million, $1.2 billion, $1.15 billion, $650.0 million and $750.0 million of senior notes maturing in 2012, 2013, 2014, 2015 and 2016, respectively. In addition, our $3.5 billion variable-rate revolving credit facility matures in 2016.

Should interest rates increase significantly, the amount of cash required to service our debt (including any future refinancing of our fixed-rate debt instruments) would increase. Additionally, from time to time, we may enter into additional interest rate swap arrangements, which could increase our exposure to variable interest rates. As a result, significant increases in interest rates could have a material adverse effect on our financial position, results of operations and cash flows.

An increase in interest rates may also cause a corresponding decline in demand for equity securities in general, and in particular, for yield-based equity securities such as our common units. A reduction in demand for our common units may cause their trading price to decline.

Operating cash flows from our capital projects may not be immediate.

We have announced and are engaged in multiple significant construction projects involving existing and new assets for which we have expended or will expend significant capital. Once construction of an asset is completed, there may be a period of time before it is placed into commercial service and begins generating operating cash flow. For example, if we build a new pipeline or expand an existing facility, the design, construction, development and installation of the new asset may occur over an extended period of time, and we may not receive any material increase in operating cash flow from the project until a period of time after it is placed in-service. If we experience any unanticipated or extended delays in generating operating cash flow from these projects, we may be required to reduce or reprioritize our capital budget, sell non-core assets, access the capital markets or decrease or limit distributions to unitholders in order to meet our capital requirements.

Our growth strategy may adversely affect our results of operations if we do not successfully integrate and manage the businesses that we acquire or if we substantially increase our indebtedness and contingent liabilities to make acquisitions.

Our growth strategy includes making accretive acquisitions. As a result, from time to time, we will evaluate and acquire assets and businesses that we believe complement our existing operations. We may be unable to successfully integrate and manage the businesses we acquire in the future. We may incur substantial expenses or encounter delays or other problems in connection with our growth strategy that could have a material adverse effect on our financial position, results of operations and cash flows. Moreover, acquisitions and business expansions involve numerous risks, such as:

§ difficulties in the assimilation of the operations, technologies, services and products of the acquired assets or businesses;

§ establishing the internal controls and procedures we are required to maintain under the Sarbanes-Oxley Act of 2002;

§ managing relationships with new joint venture partners with whom we have not previously partnered;

§ experiencing unforeseen operational interruptions or the loss of key employees, customers or suppliers;

§ inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including with their markets; and

§ diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

If consummated, any acquisition or investment would also likely result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation, amortization and accretion expenses. As a result, our capitalization and results of operations may change significantly following a material acquisition. A substantial increase in our indebtedness and contingent liabilities could have a material adverse effect on our financial position, results of operations and cash flows. In addition, any anticipated benefits of a material acquisition, such as expected cost savings or other synergies, may not be fully realized, if at all.

Acquisitions that appear to increase our operating cash flows may nevertheless reduce our operating cash flows on a per unit basis.

Even if we make acquisitions that we believe will increase our operating cash flows, these acquisitions may ultimately result in a reduction of operating cash flow on a per unit basis, such as if our assumptions regarding a newly acquired asset or business did not materialize or unforeseen risks occurred. As a result, an acquisition initially deemed accretive based on information available at the time could turn out not to be. Examples of risks that could cause an acquisition to ultimately not be accretive include our inability to achieve anticipated operating and financial projections or to integrate an acquired business successfully, the assumption of unknown liabilities for which we become liable, and the loss of key employees or key customers. If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will in making such decisions. As a result of the risks noted above, we may not realize the full benefits we expect from a material acquisition, which could have a material adverse effect on our financial position, results of operations and cash flows.

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Our actual construction, development and acquisition costs could materially exceed forecasted amounts.

We have announced and are engaged in multiple significant construction projects involving existing and new assets for which we have expended or will expend significant capital. These projects entail significant logistical, technological and staffing challenges. We may not be able to complete our projects at the costs we estimated at the time of each project's initiation or that we currently estimate. For example, material and labor costs associated with our past projects in the Rocky Mountains region increased over time due to factors such as higher transportation costs and the availability of construction personnel. Similarly, force majeure events such as hurricanes along the U.S. Gulf Coast may cause delays, shortages of skilled labor and additional expenses for these construction and development projects, such as were experienced with Hurricanes Gustav and Ike in 2008.

If capital expenditures materially exceed expected amounts, then our future cash flows could be reduced, which, in turn, could reduce the amount of cash we expect to have available for distribution. In addition, a material increase in project costs could result in decreased overall profitability of the newly constructed asset once it is placed into commercial service.

Our construction of new assets is subject to regulatory, environmental, political, legal and economic risks, which may result in delays, increased costs or decreased cash flows.

One of the ways we intend to grow our business is through the construction of new midstream energy infrastructure assets. The construction of new assets involves numerous operational, regulatory, environmental, political and legal risks beyond our control and may require the expenditure of significant amounts of capital. These potential risks include, among other things, the following:

§ we may be unable to complete construction projects on schedule or at the budgeted cost due to the unavailability of required construction personnel or materials, accidents, weather conditions or an inability to obtain necessary permits;

§ we will not receive any material increase in operating cash flows until the project is completed, even though we may have expended considerable funds during the construction phase, which may be prolonged;

§ we may construct facilities to capture anticipated future production growth in a region in which such growth does not materialize;

§ since we are not engaged in the exploration for and development of natural gas reserves, we may not have access to third party estimates of reserves in an area prior to our constructing facilities in the area. As a result, we may construct facilities in an area where the reserves are materially lower than we anticipate;

§ in those situations where we do rely on third party reserve estimates in making a decision to construct assets, these estimates may prove inaccurate;

§ the completion or success of our construction project may depend on the completion of a third party construction project (e.g., a downstream crude oil refinery expansion) that we do not control and that may be subject to numerous of its own potential risks, delays and complexities; and

§ we may be unable to obtain rights-of-way to construct additional pipelines or the cost to do so may be uneconomical.

A materialization of any of these risks could adversely affect our ability to achieve growth in the level of our cash flows or realize benefits from expansion opportunities or construction projects, which could impact the level of cash distributions we pay to partners.

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An indirect subsidiary of EPCO has pledged 65,000,000 of our common units as security under the credit facility of another privately held affiliate of EPCO. Upon an event of default under this credit facility, a change in ownership of these units could ultimately result.

Duncan Family Interests, Inc. has pledged 65,000,000 of our common units that it owns as security under the credit facility of another privately held affiliate of EPCO. This credit facility contains customary and other events of default of the borrower and certain of its affiliates, including us. An event of default, followed by a foreclosure on the pledged collateral, could ultimately result in a change in ownership of these units. A development of this nature could affect the market price of our common units.

The credit and risk profile of owners of our general partner and their privately held affiliates could adversely affect our risk profile, which could increase our borrowing costs, hinder our ability to raise capital or impact future credit ratings.

The credit and business risk profiles of the owners of our general partner and their privately held affiliates may factor into the credit evaluations of our partnership. This is because the general partner can exercise significant influence over the business activities of our partnership, including its cash distribution policy, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of owners of our general partner and their privately held affiliates, including the degree of their financial leverage and their dependence on cash flow from our partnership to service their indebtedness.

Affiliates of the entities controlling the owner of our general partner have significant indebtedness outstanding and are dependent principally on the cash distributions from their limited partner equity interests in us to service such indebtedness. Any distributions by us to such entities will be made only after satisfying our then current obligations to creditors.

Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us and our general partner from the entities that control our general partner, our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of EPCO or the entities that control our general partner were viewed as substantially lower or more risky than ours. A development of this nature could affect the market price of our common units.

The interruption of cash distributions to us from our subsidiaries and joint ventures may affect our ability to satisfy our obligations and to make cash distributions to our partners.

On a standalone basis, Enterprise Products Partners L.P. is a holding company with no business operations and conducts all of its business through its wholly owned subsidiary, EPO. As a result, we depend upon the earnings and cash flows of EPO and its subsidiaries and joint ventures, and the distribution of that cash to us in order to meet our obligations and to allow us to make cash distributions to our partners. The ability of EPO and its subsidiaries and joint ventures to make cash distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations, including FERC policies. In addition, the charter documents governing EPO's joint ventures typically allow their respective joint venture management committees sole discretion regarding the occurrence and amount of distributions. Two of the joint ventures in which EPO participates have separate credit agreements that contain various restrictive covenants. Among other things, those covenants may limit or restrict the joint venture's ability to make cash distributions to us under certain circumstances. Accordingly, EPO's joint ventures may be unable to make cash distributions to us at current levels, if at all. A material reduction in the cash distributions we receive from EPO (including those of its joint ventures) would impair our ability to pay cash distributions to our partners.

We may be unable to cause our joint ventures to take or not to take certain actions unless some or all of our joint venture participants agree.

We participate in several joint ventures. Due to the nature of some of these arrangements, each participant in these joint ventures has made substantial investments in the joint venture and, accordingly, has required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of the joint venture. These participatory and protective features customarily include a governance structure that requires at least a majority-in-interest vote to authorize many basic activities of the joint venture and requires a greater voting interest (sometimes up to 100%) to authorize more significant activities. Examples of these more significant activities are large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital, transactions with affiliates of a joint venture participant, litigation matters, and transactions not in the ordinary course of the joint venture's business, among others. Thus, without the concurrence of joint venture participants with enough voting interests, we may be unable to cause any of our joint ventures to take or not to take certain actions, even though those actions may be in the best interest of us or the particular joint venture.

Moreover, any joint venture owner may sell, transfer or otherwise modify its ownership interest in a joint venture, whether in a transaction involving third parties or the other joint venture owners. Any such transaction could result in us being required to partner with different or additional parties with whom we have not had a previous relationship.

If we are unable to agree with our joint venture partners on a significant matter, it could result in a material adverse effect on that joint venture's financial condition, results of operation or cash flows. If the matter was significant to us on a consolidated basis, it could result in a material adverse effect on our financial condition, results of operation or cash flows.

A natural disaster, catastrophe, terrorist attack or other event could result in severe personal injury, property damage and environmental damage, which could curtail our operations and have a material adverse effect on our financial position, results of operations and cash flows.

Some of our operations involve risks of personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow. For example, natural gas facilities operate at high pressures, sometimes in excess of 1,100 pounds per square inch. We also operate crude oil and natural gas facilities located underwater in the Gulf of Mexico, which can involve complexities, such as extreme water pressure. In addition, our marine transportation business is subject to additional risks, including the possibility of marine accidents and spill events. From time to time, our octane enhancement facility may produce MTBE for export, which could expose us to additional risks from spill events. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes. The location of our assets and our customers' assets in the U.S. Gulf Coast region makes them particularly vulnerable to hurricane or tropical storm risk. In addition, terrorists may target our physical facilities and hackers may attack our electronic systems.

If one or more facilities or electronic systems that we own or that deliver products to us or that supply our facilities are damaged by severe weather or any other disaster, accident, catastrophe, terrorist attack or event, our operations could be significantly interrupted. These interruptions could involve significant damage to people, property or the environment, and repairs could take from a week or less for a minor incident to six months or more for a major interruption. Additionally, some of the storage contracts that we are a party to obligate us to indemnify our customers for any damage or injury occurring during the period in which the customers' product is in our possession. Any event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions and, accordingly, adversely affect the market price of our securities.

We believe that EPCO maintains adequate insurance coverage on our behalf, although insurance will not cover many types of interruptions that might occur, will not cover amounts up to applicable deductibles and will not cover all risks associated with certain of our products. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. For example, following the hurricanes in 2005 and 2008, certain types of insurance coverage for our Gulf of Mexico assets have become more expensive. In the future, circumstances may arise whereby EPCO may not be able to renew existing insurance policies on our behalf or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

An impairment of goodwill and intangible assets could reduce our earnings.

At December 31, 2011, our consolidated balance sheet reflected $2.09 billion of goodwill and $1.66 billion of intangible assets. Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Generally accepted accounting principles ("GAAP") in the U.S. require us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that any of our goodwill or intangible assets were impaired, we would be required to take an immediate non-cash charge to earnings with a correlative effect on partners' equity and balance sheet leverage as measured by debt to total capitalization. For information regarding our Critical Accounting Policies and Estimates, see Item 7 of this annual report.

The use of derivative financial instruments could result in material financial losses by us.

Historically, we have sought to limit a portion of the adverse effects resulting from changes in energy commodity prices and interest rates by using derivative instruments. Derivative instruments typically include futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

To the extent that we hedge our commodity price and interest rate exposures, we will forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though monitored by management, hedging activities can result in losses that might be material to our financial condition, results of operations and cash flows. Such losses could occur under various circumstances, including those situations where a counterparty does not perform its obligations under a hedge arrangement, the hedge is not effective in mitigating the underlying risk, or our risk management policies and procedures are not followed. Adverse economic conditions, such as the financial crisis that developed in the fourth quarter of 2008 and continued into 2009, increase the risk of nonpayment or performance by our hedging counterparties.

See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for a discussion of our derivative instruments and related hedging activities.

Our business requires extensive credit risk management that may not be adequate to protect against customer nonpayment.

Risks of nonpayment and nonperformance by customers are a major consideration in our businesses, and our credit procedures and policies may not be adequate to sufficiently eliminate customer credit risk. Further, adverse economic conditions, such as the credit crisis that developed in the fourth quarter of 2008 and continued into 2009, increase the risk of nonpayment and nonperformance by customers, particularly customers that are smaller companies. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments, net out agreements and guarantees. However, these procedures and policies do not fully eliminate customer credit risk.

Our primary market areas are located in the Gulf Coast, Southwest, Rocky Mountain, Northeast and Midwest regions of the U.S. We have a concentration of trade receivable balances due from major integrated oil companies, independent oil companies and other pipelines and wholesalers. These concentrations of market areas may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors.

Our consolidated revenues are derived from a wide customer base. Our largest non-affiliated customer for 2011, 2010 and 2009 was Shell Oil Company and its affiliates, which accounted for 10.6%, 9.4% and 9.8% of our consolidated revenues, respectively.

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See Note 2 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for a discussion of our allowance for doubtful accounts.

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

When engaged in marketing activities, it is our policy to maintain physical commodity positions that are substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Through these transactions, we seek to earn a margin for the commodity purchased by selling the same commodity for physical delivery to third party users, such as producers, wholesalers, independent refiners, marketing companies or major oil companies. These policies and practices cannot, however, eliminate all price risks. For example, any event that disrupts our anticipated physical supply could expose us to risk of loss resulting from price changes if we are required to obtain alternative supplies to cover these transactions. We are also exposed to basis risks when a commodity is purchased against one pricing index and sold against a different index. Moreover, we are exposed to some risks that are not hedged, including price risks on product inventory, such as pipeline linefill, which must be maintained in order to facilitate transportation of the commodity on our pipelines. In addition, our marketing operations involve the risk of non-compliance with our risk management policies. We cannot assure you that our processes and procedures will detect and prevent all violations of our risk management policies, particularly if deception or other intentional misconduct is involved. If we were to incur a material loss related to commodity price risks, including non-compliance with our risk management policies, it could have a material adverse effect on our financial position, results of operations and cash flows.

Our pipeline integrity program as well as compliance with proposed pipeline safety legislation and periodic tank maintenance requirements may impose significant costs and liabilities on us.

The DOT requires pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in HCAs. The majority of the costs to comply with this integrity management rule are associated with pipeline integrity testing and any repairs found to be necessary as a result of such testing. Changes such as advances of in-line inspection tools, identification of additional threats to a pipeline’s integrity and changes to the amount of pipe determined to be located in HCAs can have a significant impact on the costs to perform integrity testing and repairs. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

The DOT has extended its pipeline safety regulations, including integrity management requirements, to certain rural onshore hazardous liquid gathering lines and certain rural onshore low-stress hazardous liquid pipelines within a buffer area around “unusually sensitive areas.” In May 2011, the DOT issued the second phase of the Final Rule applying pipeline safety regulations to all remaining rural low stress pipelines. The issuance of these gathering and low-stress pipeline safety regulations, including requirements for integrity management of those pipelines, is likely to increase the operating costs of our pipelines subject to such new requirements.

In January 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 into law. This legislation provides stronger oversight of the nation’s pipelines, increases the penalties for violations of pipeline safety rules, and complements the DOT’s other initiatives. This legislation increases the maximum fine for the most serious pipeline safety violations involving deaths, injuries or major environmental harm from $1 million to $2 million. In addition, the legislation improves pipeline transportation and safety by: (i) improving pipeline damage prevention measures and cracking down on third party pipeline damage; (ii) allowing the Transportation Secretary to require automatic and remote-controlled shut-off valves on new pipelines; (iii) requiring the Transportation Secretary to evaluate the effectiveness of expanding pipeline integrity management and leak detection requirements; (iv) improving the way the DOT and pipeline operators provide information to the public and emergency responders; and (v) reforming the process by which pipeline operators notify federal, state and local officials of pipeline accidents.

The American Petroleum Institute Standard 653 ("API 653") is an industry standard for the inspection, repair, alteration and reconstruction of existing storage tanks. API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Periodic tank maintenance requirements could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our storage tanks.

If we were to incur material costs in connection with our pipeline integrity program or new pipeline safety legislation or periodic tank maintenance requirements, it could have a material adverse effect on our financial condition, results of operations and cash flows.

Additional regulations that cause delays or deter new offshore oil and gas drilling could have a material adverse effect on our financial position, results of operations and cash flows.

In April 2010, in an event unrelated to Enterprise's operations, the Deepwater Horizon drilling rig caught fire and sank in the Gulf of Mexico, resulting in an oil spill. As a result, in May 2010, the U.S. Department of the Interior ("Interior Department") issued a six-month moratorium that halted drilling of uncompleted and new oil and gas wells (in water deeper than 500 feet) in the Gulf of Mexico with certain limited exceptions and halted consideration of drilling permits for deepwater wells. In addition to the moratorium, the Interior Department also canceled or delayed offshore oil and gas lease sales off the Mid-Atlantic coast and in Alaska. The Secretary of the Interior ("Interior Secretary") withdrew the moratorium and replaced it in July 2010 with a suspension of certain offshore drilling activities that was to be effective through October 2010.

The drilling suspension was finally lifted by the Interior Secretary on October 12, 2010. However, the timing and process for approving applications for new permits to drill and the cost associated with compliance with various new and enhanced safety and environmental requirements (as discussed below) imposed following the Deepwater Horizon incident remains uncertain. The Interior Department has indicated that it will not issue drilling permits until well operators demonstrate that safety and environmental protection requirements for offshore exploration and production can be met. In general, and as discussed in greater detail below, well operators have been required to show that containment resources are available promptly in the event of another blowout and to certify that they have complied with all applicable regulations, including new drilling safety rules. At the end of February 2011, the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE"), an office of the Interior Department which is charged with oversight of the United States' oil, natural gas and other mineral resources on the Outer Continental Shelf, approved the first drilling permit that would have been subject to the drilling suspension.

In 2010, the BOEMRE issued a series of rules that increased regulatory requirements for offshore oil and gas operations. In June 2010, the BOEMRE issued a notice to holders of offshore oil and gas leases requiring compliance certifications and third party verification of certain inspection and design matters. Subsequently, the BOEMRE issued a notice to lessees that called for enhanced information regarding planning scenarios relating to blowouts, discharges of pollutants and prevention of accidents. In August 2010, another notice to lessees revised the environmental review process for offshore oil and gas development. In October 2010, the BOEMRE published an emergency drilling safety rule that imposed additional requirements for well bore integrity and well control equipment and procedures, including provisions addressing blowout preventers and the use of drilling fluids. This interim final rule became effective immediately, but is subject to future changes that may be made by the regulatory agency in response to public comments. In October 2010, the BOEMRE also published a final rule requiring safety and environmental management systems for all oil and gas operations on the Outer Continental Shelf. In November 2010, the BOEMRE issued a notice to lessees requiring certifications and a demonstration that the well operator has access to and can deploy containment resources adequate to respond to a blowout or other loss of well control. Effective October 2011, the BOEMRE was reorganized and replaced by the Bureau of Ocean Energy Management (the "BOEM") and the Bureau of Safety and Environment Enforcement.

In addition to federal regulatory activity, at least one state has ordered enhanced inspections of oil and gas rigs and required more stringent disaster preparedness plans, and it is possible that other state-level requirements will be imposed on offshore energy production activities.

The effect of new regulatory requirements on offshore energy development in the Gulf of Mexico following the Deepwater Horizon incident, including the prospects and timing of securing permits for offshore energy production activities, are evolving and uncertain. Such uncertainty may cause companies to curtail or delay

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oil and gas drilling activities, or to redirect resources to other areas such as West Africa, the Caribbean or South America, which may further delay the resumption of drilling activity in the Gulf of Mexico. It is uncertain at this time how and to what extent oil and natural gas supplies from the Gulf of Mexico and other offshore drilling areas will be affected.

In addition to federal regulatory actions, numerous legislative proposals were introduced in the 111th U.S. Congress in reaction to the Deepwater Horizon incident, some of which may be considered in the current legislative session. However, it is unclear and cannot be predicted whether and when Congress may pass legislation. Bills that have received attention include measures to: (i) modify or revoke liability limits and caps under the Oil Spill Liability Trust Fund, the OPA and certain other statutes; (ii) revise federal liability regimes to include health effects, personal injuries, and other tort claims; (iii) mandate more stringent safety measures and inspections under the OPA and OCSLA; (iv) expand environmental reviews and lengthen review timelines; (v) impose fees, increase taxes or remove tax exemptions; (vi) modify financial responsibility and insurance requirements for offshore energy activities; and (vii) require U.S. registration of oil rigs.

Given the scope and effect of the Deepwater Horizon incident to date, as well as statements made by the Interior Secretary, it is expected that additional regulatory compliance and agency review will be required prior to permitting new wells or continued drilling of existing wells, which may affect the cost and timing of oil and gas drilling in the Gulf of Mexico and other offshore areas. A decline in, or failure to achieve anticipated volumes of oil and natural gas supplies due to any of the foregoing factors could have a material adverse effect on our financial position, results of operations and cash flows through reduced gathering and transportation volumes, processing activities, or other midstream services.

Environmental costs and liabilities and changing environmental regulation, including climate change regulation, could have a material adverse effect on our financial position, results of operations and cash flows.

Our operations are subject to various environmental and safety requirements and potential liabilities under extensive federal, state and local laws and regulations. Further, we cannot ensure that existing environmental regulations will not be revised or that new regulations, such as regulations designed to reduce the emissions of greenhouse gases, will not be adopted or become applicable to us. Governmental authorities have the power to enforce compliance with applicable regulations and permits and to subject violators to civil and criminal penalties, including substantial fines, injunctions or both. Certain environmental laws, including CERCLA and analogous state laws and regulations, may impose strict, joint and several liability for costs required to clean-up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, third parties, including neighboring landowners, may also have the right to pursue legal actions to enforce compliance or to recover for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Future environmental law developments, such as stricter laws, regulations, permits or enforcement policies, could significantly increase some costs of our operations, including those incurred in connection with the handling, manufacture, use, emission or disposal of substances and wastes.

Climate Change Risks

Climate change regulation is one area of potential future environmental law development. Responding to scientific reports regarding threats posed by global warming, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases. In addition, some states, including states in which our facilities or operations are located, have individually or in regional cooperation, imposed restrictions on greenhouse gas emissions under various policies and approaches, including establishing a cap on emissions, requiring efficiency measures, or providing incentives for pollution reduction, use of renewable energy sources, or use of replacement fuels with lower carbon content. Among these, ten states in the Northeast and Mid-Atlantic region signed a compact and have implemented rules to limit carbon dioxide emissions from power plants under the RGGI, which requires electric generation facilities to purchase emissions allowances corresponding to their respective emissions under a cap-and-trade system. The CARB has issued a series of rules under that state's Global Warming Solutions Act, including restrictions on greenhouse gas emissions from industrial sources and regulating the carbon content of fuels. Beginning in January 2012, the CARB requires certain emission sources in California to acquire allowances for

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greenhouse gas emissions under its cap-and-trade system. In addition, in November 2010, the New Mexico Environmental Improvement Board adopted new regulations pursuant to state laws establishing a greenhouse gas cap-and-trade system to be implemented by the New Mexico Environment Department; however, this program was repealed in February 2012.

The EPA has also taken action under the CAA to regulate greenhouse gas emissions. In November 2010, the EPA finalized rules expanding its Mandatory Greenhouse Gas Reporting Rule, originally promulgated in October 2009, to be applicable to the oil and natural gas industry, which may affect certain of our existing or future operations and require us to inventory and report our emissions. In addition, the EPA has taken the position that existing CAA provisions require an assessment of greenhouse gas emissions within the permitting process for certain large new or modified stationary sources under the EPA's PSD and Title V permit programs. Facilities triggering permit requirements may be required to reduce greenhouse gas emissions consistent with "best available control technology" standards if deemed to be cost-effective. Such changes will also affect state air permitting programs in states that administer the CAA under a delegation of authority, including states in which we have operations. The EPA has also announced its intention to promulgate additional regulations restricting greenhouse gas emissions, including rules applicable to the power generation sector and oil refining sector.

The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur significant costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the crude oil, natural gas or other hydrocarbon products that we transport, store or otherwise handle in connection with our midstream services. The potential increase in our operating costs could include costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions, and administer and manage a greenhouse gas emissions program. We may not be able to recover such increased costs through customer prices or rates. In addition, changes in regulatory policies that result in a reduction in the demand for hydrocarbon products that are deemed to contribute to greenhouse gases, or restrictions on their use, may reduce volumes available to us for processing, transportation, marketing and storage.

Moreover, there have been several court cases implicating greenhouse gas emissions and climate change issues that could establish precedent that may indirectly affect our business, customers or the energy sector in general. First, in September 2009, the U.S. Court of Appeals for the Second Circuit issued its decision in Connecticut v. American Electric Power Co., 582 F.3d 309 (2d Cir. Sept. 21, 2009). With this case, the Second Circuit held that certain state and private plaintiffs could sue energy companies on the asserted basis that greenhouse gas emissions created a "public nuisance." However, in June 2011, the U.S. Supreme Court held that the CAA and EPA actions displace the right to seek abatement of emissions under federal common law but left open whether state law tort actions were pre-empted. Second, a three-judge panel of the U.S. Court of Appeals for the Fifth Circuit initially upheld claims in Comer v. Murphy Oil USA, 585 F.3d 855 (5th Cir. Oct. 16, 2009), by property owners who suffered casualty losses in Hurricane Katrina alleging that certain energy, fossil fuel and chemical industries emitted greenhouse gases that contribute to global warming and ultimately exacerbated property damage from the hurricane. The Fifth Circuit subsequently vacated the panel decision, and because of a procedural issue, was unable to review the merits of the claims. In May 2011, the case was refiled in the Southern District of Mississippi with a focus on state law causes of action. A similar case, Native Village of Kivalina v. ExxonMobil Corp., 663 F. Supp. 2d 863 (N.D. Cal. Sept. 30, 2009), dismissed similar claims for lack of subject matter jurisdiction, and this decision was appealed to U.S. Court of Appeals for the Ninth Circuit where oral argument was heard in November 2011. These cases could establish legal precedent that may expose other significant emission sources of greenhouse gases to similar litigation risk.

These developments, or any future actions, could have a material adverse effect on our financial position, results of operations and cash flows. While we may be able to include some or all of such increased costs in the rates charged by our pipelines or other facilities, such recovery of costs is uncertain and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC and the provisions of any final legislation.

In addition, global warming could have an impact on our physical operations and energy markets. For example, our facilities that are located in low lying areas such as the coastal regions of Louisiana and Texas may be at increased risk due to flooding, rising sea levels, or disruption of operations from more frequent and severe weather events. Facilities in areas with limited water availability may be impacted if droughts become more frequent or severe. Changes in climate or weather may hinder exploration and production activities or increase or decrease the cost of production of oil and gas resources and consequently affect the volume of hydrocarbon products entering our system. Changes in climate or weather may also affect consumer demand for energy or alter the overall energy mix.

Hydraulic Fracturing Risks

Certain of our customers employ hydraulic fracturing techniques to stimulate natural gas production from unconventional geological formations (including shale formations), which entails the injection of pressurized fracturing fluids (consisting of water, sand and certain chemicals) into a well bore. The federal Energy Policy Act of 2005 amended the Underground Injection Control provisions of the federal Safe Drinking Water Act ("SDWA") to exclude hydraulic fracturing from the definition of "underground injection" under certain circumstances. However, the repeal of this exclusion has been advocated by certain advocacy organizations and others in the public. Legislation to amend the SDWA to repeal this exemption and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical components of the fluids used in the fracturing process, were proposed in recent sessions of Congress. Similar legislation could be introduced in the future.

The EPA has commenced a study of the potential environmental impact of hydraulic fracturing, the results of which are anticipated to be available in late 2012. A recent EPA report related to hydraulic fracturing in a production field in Wyoming suggested that there may be a connection between hydraulic fracturing and water quality at the site, although the data remains in dispute. In addition, in October 2011, the EPA announced its intention to propose regulations by 2014 under the CWA to regulate wastewater discharges from hydraulic fracturing and other natural gas production activities. Last year, a committee of the U.S. House of Representatives commenced investigations into hydraulic fracturing practices. The Interior Department has announced that it will consider regulations relating to the use of hydraulic fracturing techniques on public lands and disclosure of fracturing fluid components.

Some states and localities have adopted, and others are considering adopting, regulations or ordinances that could restrict hydraulic fracturing in certain circumstances, or that would impose higher taxes, fees or royalties on natural gas production. For example, New York has imposed a de facto moratorium on the issuance of permits for certain hydraulic fracturing practices until an environmental review and potential new regulations are finalized. Significant controversy has surrounded hydraulic fracturing operations in the Marcellus Shale in Pennsylvania. Wyoming has also adopted legislation requiring drilling operators conducting hydraulic fracturing activities in that state to publicly disclose the chemicals used in the fracturing process. Lastly, Colorado and Texas now require recordkeeping and disclosure of fracturing fluid components to state officials under certain circumstances.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and gas drilling activities using hydraulic fracturing techniques, including increased litigation. Additional legislation or regulation could also lead to operational delays and/or increased operating costs in the production of oil and natural gas (including natural gas produced from shale plays like the Eagle Ford Shale, Haynesville Shale, Barnett Shale and Marcellus and Utica Shales) incurred by our customers or could make it more difficult to perform hydraulic fracturing. If these legislative and regulatory initiatives cause a material decrease in the drilling of new wells and related servicing activities, it may affect the volume of hydrocarbon projects available to our midstream business and have a material adverse effect on our financial position, results of operations and cash flows.

Recently proposed rules regulating air emissions from oil and natural gas operations could cause us to incur increased capital expenditures and operating costs, which may be significant.

In July 2011, the EPA proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's proposed rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs"), and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The EPA's proposal would require the reduction of VOC emissions from

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oil and natural gas production facilities by mandating the use of "green completions" for hydraulic fracturing, which requires the operator to recover rather than vent the gas and NGLs that come to the surface during completion of the fracturing process. The proposed rules also would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules would establish new leak detection requirements for natural gas processing plants. The EPA will receive public comment and hold hearings regarding the proposed rules and must take final action on them during the first quarter of 2012. If finalized, these rules could require a number of modifications to our operations including the installation of new leak detection and related equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, which may adversely impact our business.

Federal, state or local regulatory measures could have a material adverse effect on our financial position, results of operations and cash flows.

The FERC regulates our interstate natural gas pipelines and natural gas storage facilities under the NGA, and our interstate NGL and petrochemical pipelines under the ICA. The STB regulates our interstate propylene pipelines. State regulatory agencies regulate our intrastate natural gas and NGL pipelines, intrastate storage facilities and gathering lines.

Under the NGA, the FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Its authority to regulate those services is comprehensive and includes the rates charged for such services, terms and conditions of service, and certification and construction of new natural gas facilities for transportation service in interstate commerce. The FERC requires that our services are provided on a nondiscriminatory basis so that all shippers have open access to our interstate pipelines. Pursuant to the FERC's jurisdiction over interstate natural gas pipeline rates, existing pipeline rates may be challenged by customer complaint or by the FERC, and proposed rate increases may be challenged by protest.

We have ownership interests in natural gas and crude oil pipeline facilities located in the Gulf of Mexico offshore Texas and Louisiana. These facilities are subject to regulation by the FERC and other federal agencies, including the Interior Department, under the OCSLA, and by the DOT's OPS under the NGPSA.

Our intrastate NGL and natural gas pipelines are subject to regulation in many states, including Colorado, Louisiana, New Mexico, Texas and Wyoming. To the extent our intrastate pipelines engage in interstate transportation, they are also subject to regulation by the FERC pursuant to Section 311 of the NGPA. We also have natural gas underground storage facilities in Louisiana and Texas. Although state regulation is typically less onerous than regulation by the FERC, our provision of services on a nondiscriminatory basis are also subject to challenge by protest and complaint, respectively.

Although our natural gas gathering systems are generally exempt from FERC regulation under the NGA, our natural gas gathering operations could be adversely affected should they become subject to federal regulation of rates and services, or, if the states in which we operate adopt policies imposing more onerous regulation on gas gathering operations. Additional rules and legislation pertaining to these matters are considered and adopted from time to time at both state and federal levels. We cannot predict what effect, if any, such regulatory changes and legislation might have on our operations, but we could be required to incur additional capital expenditures.

Increasingly stringent federal, state and local laws and regulations governing worker health and safety and the construction and operation of marine vessels may significantly affect our marine transportation operations. Many aspects of the marine transportation industry are subject to extensive governmental regulation by the USCG, the DOT, the Department of Homeland Security, the National Transportation Safety Board ("NTSB") and the U.S. Customs and Border Protection, and to regulation by private industry organizations such as the ABS. The USCG and the NTSB set safety standards and are authorized to investigate vessel accidents and recommend improved safety standards. The USCG is authorized to inspect vessels at will.

For a general overview of federal, state and local regulation applicable to our assets, see "Regulation" included within Item 1 and 2 of this annual report. This regulatory oversight can affect certain aspects of our business and the market for our products and could materially adversely affect our cash flows.

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We are subject to strict regulations at many of our facilities regarding employee safety, and failure to comply with these regulations could adversely affect our ability to make distributions to unitholders.

The workplaces associated with our facilities are subject to the requirements of 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 we maintain information about hazardous materials used or produced in our operations and that we provide this information to employees, state and local governmental authorities and local residents. The failure to comply with OSHA requirements or general industry standards, keep adequate records or monitor occupational exposure to regulated substances could expose us to liability, enforcement, and fines and penalties, and could have a material adverse effect on our financial position, results of operations and cash flows.

The rates of our regulated assets are subject to review and possible adjustment by federal and state regulators, which could adversely affect our revenues.

The FERC, pursuant to the ICA (as amended), the Energy Policy Act and rules and orders promulgated thereunder, regulates the tariff rates for our interstate common carrier pipeline operations. To be lawful under the ICA, interstate tariff rates, terms and conditions of service must be just and reasonable and not unduly discriminatory, and must be on file with the FERC. In addition, pipelines may not confer any undue preference upon any shipper. Shippers may protest (and the FERC may investigate) the lawfulness of new or changed tariff rates. The FERC can suspend those tariff rates for up to seven months. It can also require refunds of amounts collected pursuant to rates that are ultimately found to be unlawful and prescribe new rates prospectively. The FERC and interested parties can also challenge tariff rates that have become final and effective. The FERC also can order new rates to take effect prospectively and order reparations for past rates that exceed the just and reasonable level up to two years prior to the date of a complaint. Due to the complexity of rate making, the lawfulness of any rate is never assured. A successful challenge of our rates could adversely affect our revenues.

The FERC uses prescribed rate methodologies for approving regulated tariff rates for interstate liquids pipelines. The FERC's indexing methodology currently allows a pipeline to increase its rates by a percentage linked to the PPI. As an alternative to using the indexing methodology, interstate liquids pipelines may elect to support rate filings by using a cost-of-service methodology, market-based rates or agreements with all of the pipeline's shippers that the rate is acceptable. These methodologies may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting increased costs. Changes in the FERC's approved methodology for approving rates, or challenges to our application of that methodology, could adversely affect us. Adverse decisions by the FERC in approving our regulated rates could adversely affect our cash flow.

The intrastate liquids pipeline transportation services we provide are subject to various state laws and regulations that apply to the rates we charge and the terms and conditions of the services we offer. Although state regulation typically is less onerous than FERC regulation, the rates we charge and the provision of our services may be subject to challenge.

Our partnership status may be a disadvantage to us in calculating our cost of service for rate-making purposes.

In May 2005, the FERC issued a policy statement permitting the inclusion of an income tax allowance in the cost of service-based rates of a pipeline organized as a tax pass through partnership entity to reflect actual or potential income tax liability on public utility income, if the pipeline proves that the ultimate owners of its partnership interests have an actual or potential income tax liability on such income. The policy statement also provides that whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. In December 2005, the FERC issued its first significant case-specific review of the income tax allowance issue in another pipeline partnership's rate case. The FERC reaffirmed its new income tax allowance policy and directed the subject pipeline to provide certain evidence necessary for the pipeline to determine its income tax allowance. The new tax allowance policy and the December 2005 order were appealed to the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit"). The D.C. Circuit denied these appeals in May 2007 and fully upheld the FERC's new tax allowance policy and the application of that policy in the December 2005 order.

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In December 2006, the FERC issued a new order addressing rates on another pipeline. In the new order, the FERC refined its income tax allowance policy, and notably raised a new issue regarding the implication of the policy statement for publicly traded partnerships. It noted that the tax deferral features of a publicly traded partnership may cause some investors to receive, for some indeterminate duration, cash distributions in excess of their taxable income, which the FERC characterized as a "tax savings." The FERC stated that it is concerned that this created an opportunity for those investors to earn an additional return, funded by ratepayers. Responding to this concern, the FERC chose to adjust the pipeline's equity rate of return downward based on the percentage by which the publicly traded partnership's cash flow exceeded taxable income.

In April 2008, the FERC issued a policy statement in which it declared that it would permit master limited partnerships ("MLPs"), such as us, to be included in rate of return proxy groups for determining rates for services by natural gas and crude oil pipelines. It also addressed the application to limited partnership pipelines of the FERC's discounted cash flow methodology for determining rates of return on equity. The FERC applied the new policy to several ongoing proceedings involving other pipelines. The FERC's rate of return policy remains subject to change.

In February 2011 and December 2011, the FERC issued an order and rehearing order in a pipeline proceeding addressing issues related to the inclusion of an income tax allowance for partnerships, particularly MLPs.

In each order, the FERC, among other things, reaffirmed its tax allowance policy, MLP Policy Statement, and the findings of the D. C. Circuit's May 2007 opinion regarding the income tax allowance and related issues, and rejected arguments that challenged its current income tax policy (i.e., certain parties claimed that granting an MLP an income tax allowance results in a double recovery of the partner's income taxes and claimed that an MLP's regulatory return should be adjusted to reflect the benefit of tax deferrals from owning a partnership interest).

However, the FERC's current income tax allowance policy and related issues continue to be contested issues and the FERC's policy remains subject to change. Future challenges to the FERC's treatment of income tax allowances in cost of service, particularly with respect to pipelines organized as partnerships, could result in changes to the FERC's current policy and could adversely affect our revenues for any of our rates that are calculated using cost of service rate methodologies.

The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

The Dodd-Frank Wall Street Reform and Consumer Protection Act enacted in 2010 (the "Dodd-Frank Act") provides for new statutory and regulatory requirements for swaps and other financial derivative transactions, including oil and gas hedging transactions. Under the Dodd-Frank Act, we will be required to transact "clearable" derivatives on a Designated Contract Market ("DCM") or a Swap Execution Facility ("SEF") such as a futures exchange or board of trade registered with the Commodity Futures Trading Commission ("CFTC"). All derivative transactions including those that are not clearable on such a platform and are therefore executed on an over-the-counter, bi-lateral basis may be subject to new requirements that involve recordkeeping and reporting requirements, position limits and additional cash collateral or margin requirements. The Dodd-Frank Act requires the CFTC, federal regulators of banks and other financial institutions, or the prudential regulators, and the SEC to promulgate rules implementing the new law.

On October 18, 2011, the CFTC issued its final position limits rules under the Dodd-Frank Act. The position limit rules enumerated certain energy futures contracts as referenced contracts including NYMEX Light Sweet Crude Oil, New York Harbor Gasoline Blendstock, New York Harbor Heating Oil and Henry Hub Natural Gas. Any referenced contract or associated contracts directly or indirectly linked to a referenced contract will be subject to the new position limits rules. These rules include spot month limits and non-spot month limits which can only be exceeded by positions that meet certain criteria to qualify as a Bona Fide Hedge. Invoking Bona Fide Hedges will require new reporting requirements including the reporting of anticipatory transactions, transactions relying on pass through hedge exemptions and reporting where certain visibility levels are met or exceeded. The position limit rules will go into effect 60 days after the term "swap" is defined by the CFTC. While there is still some uncertainty with respect to how the enumerated bona fide hedging qualifications will be interpreted, we anticipate that substantially all of our derivative transactions would qualify as Bona Fide Hedges.

On July 14, 2011, the CFTC granted temporary exemptive relief from certain provisions of the Commodity Exchange Act that otherwise would have taken effect on July 16, 2011, the general effective date of title VII of the Dodd-Frank Act. On October 25, 2011, the CFTC proposed to extend the exemptive relief beyond the December 31, 2011 expiration date. On December 19, 2011, the CFTC issued a Final Order regarding the effective date for swap regulation, which addressed the comments received on the October 25, 2011, Notice of Proposed Amendment, and extended the potential latest expiration date of the exemptive relief to July 16, 2012. The CFTC continues to make progress on its rulemaking efforts and has not yet indicated an earlier expiration date for the exemptive relief granted.

On December 20, 2011, the CFTC approved two final rules that addressed how swap data will be reported to regulators and separately to the public. One rule established recordkeeping requirements and a regulatory reporting regime for swap markets. The other rule established a reporting regime for the public dissemination of swap transaction data in real-time. Both rules affect swap dealers, major swap participants, swap counterparties that are neither swap dealers or major swap participants including end-users, swap data repositories, swap execution facilities, designated contract markets and derivatives clearing organizations. While we do not believe the internal costs of reporting will be material to us, we have not been able to assess the full impact of these rules on our counterparties and our marketing and hedging activities. Costs of compliance by our counterparties, particularly with the use of pass through hedge exemptions, will likely be passed on to customers such as ourselves, thus decreasing the benefits to us of hedging transactions and reducing our profitability. In addition, the new recordkeeping and reporting rules expose us to the risk of financial penalties or disqualifications of transactions as Bona Fide Hedges due to potential failures in compliance with the documentation requirements.

The CFTC has not yet released final rules on margin or collateral requirements; however, it is possible that any new rules will increase the amount of cash required to support exchange and over-the-counter derivative transactions. The majority of our financial derivative transactions used for hedging purposes are currently executed and cleared over exchanges that already require the posting of margins or letters of credit based on initial and variation margin requirements. Depending on the rules and definitions adopted by the CFTC, we might in the future be required to provide additional cash margin or new cash collateral for our commodities hedging transactions whether cleared over an exchange or over-the-counter. Furthermore, it is possible that letters of credit issued by banks on our behalf will no longer be considered an acceptable form of margin support which would increase overall cash margin requirements.

Posting of additional cash margin or collateral could affect our liquidity (defined as unrestricted cash on hand plus available credit under our revolving credit facility) and reduce our ability to use cash for capital expenditures or other partnership purposes. A requirement to post additional cash margin or collateral could therefore reduce our ability to execute hedges necessary to reduce commodity price exposures thus protecting cash flows. We are at risk for reduced liquidity unless and until the CFTC adopts rules and definitions that relieve companies such as ourselves from requirements to post additional cash margins or collateral for our exchange or over-the-counter derivative hedging activities. Even if we ourselves are not required to post additional cash margin or collateral for our derivative contracts, the banks and other derivatives dealers who are our contractual counterparties will be required to comply with other new requirements under the Dodd-Frank Act and related rules, and the costs of their compliance will likely be passed on to customers such as ourselves, thus decreasing the benefits to us of hedging transactions and reducing our profitability.

EPCO’s employees may be subjected to conflicts in managing our business and the allocation of their time and compensation costs between our business and the business of EPCO and its other affiliates.

We have no officers or employees and rely solely on officers of our general partner and employees of EPCO. Certain of our general partner's officers are also officers of EPCO and other affiliates of EPCO. These relationships may create conflicts of interest regarding business opportunities and other matters, and the resolution of any such conflicts may not always be in our or our unitholders' best interests. In addition, these overlapping officers and employees allocate their time among us, EPCO and other privately held affiliates of EPCO. These

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officers and employees face potential conflicts regarding the allocation of their time, which could have a material adverse effect on our financial position, results of operations and cash flows.

We do not have a separate compensation committee, and certain elements of the compensation of our executive officers and other key employees (other than our CEO), including base salary, are not reviewed or approved by our independent directors. The Audit Committee of our general partner approves grants of equity awards under EPCO's long-term incentive plans, including those granted to our CEO. The determination of executive officer and key employee compensation could involve conflicts of interest resulting in economically unfavorable arrangements for us. For a discussion of our executive compensation policies and procedures, see Item 11 of this annual report.

Risks Relating to Our Partnership Structure

We may issue additional securities without the approval of our common unitholders.

At any time, we may issue an unlimited number of limited partner interests of any type (to parties other than our affiliates) without the approval of our unitholders. Our partnership agreement does not give our common unitholders the right to approve the issuance of equity securities, including equity securities ranking senior to our common units. The issuance of additional common units or other equity securities of equal or senior rank will have the following effects: (i) the ownership interest of a unitholder immediately prior to the issuance will decrease; (ii) the amount of cash available for distribution on each common unit may decrease; (iii) the ratio of taxable income to distributions may increase; (iv) the relative voting strength of each previously outstanding common unit may be diminished; and (v) the market price of our common units may decline.

We may not have sufficient operating cash flows to pay cash distributions at the current level following establishment of cash reserves and payments of fees and expenses.

Because cash distributions on our common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance and capital needs. We cannot guarantee that we will continue to pay distributions at the current level each quarter. The actual amount of cash that is available to be distributed each quarter will depend upon numerous factors, some of which are beyond our control and the control of our general partner. These factors include, but are not limited to: (i) the volume of the products that we handle and the prices we receive for our services; (ii) the level of our operating costs; (iii) the level of competition in our business; (iv) prevailing economic conditions, including the price of and demand for oil, natural gas and other products we transport, store and market; (v) the level of capital expenditures we make; (vi) the amount and cost of capital we can raise compared to the amount of our capital expenditures and debt service requirements; (vii) restrictions contained in our debt agreements; (viii) fluctuations in our working capital needs; (ix) weather volatility; (x) cash outlays for acquisitions, if any; and (xi) the amount, if any, of cash reserves required by our general partner in its sole discretion.

Furthermore, the amount of cash that we have available for distribution is not solely a function of profitability, which will be affected by non-cash items such as depreciation, amortization and provisions for asset impairments. Our cash flows are also impacted by borrowings under credit agreements and similar arrangements. As a result, we may be able to make cash distributions during periods when we record losses and may not be able to make cash distributions during periods when we record net income. An inability on our part to pay cash distributions to partners could have a material adverse effect on our financial position, results of operations and cash flows.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash, after taking into account reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our common units and other limited partner interests may decrease in correlation with any reduction in our cash distributions per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

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Cost reimbursements and fees payable to EPCO and its affiliates, including our general partner, may be substantial and will reduce cash available for distribution to our unitholders.

Prior to making any distribution on our common units, we will reimburse EPCO and its affiliates, including officers and directors of our general partner, for all expenses they incur on our behalf, including allocated overhead. These amounts include all costs incurred in managing and operating our business, including costs for providing administrative staff and other support services to us, and overhead allocated to us by EPCO. Payment of these amounts could adversely affect our ability to pay cash distributions to our unitholders. EPCO has sole discretion to determine the amount of these expenses. In addition, EPCO and its affiliates may provide other services to us for which we will be charged fees as determined by EPCO.

Our general partner and its affiliates have limited fiduciary responsibilities to, and conflicts of interest with respect to, our partnership, which may permit it to favor its own interests to your detriment.

The directors and officers of our general partner and its affiliates have duties to manage our general partner in a manner that is beneficial to its members. At the same time, our general partner has duties to manage our partnership in a manner that is beneficial to us. Therefore, our general partner's duties to us may conflict with the duties of its officers and directors to its members. Such conflicts may include, among others, the following:

§ neither our partnership agreement nor any other agreement requires our general partner or EPCO to pursue a business strategy that favors us;

§ decisions of our general partner regarding the amount and timing of asset purchases and sales, cash expenditures, borrowings, issuances of additional units, and the establishment of additional reserves in any quarter may affect the level of cash available to pay quarterly distributions to our unitholders;

§ under our partnership agreement, our general partner determines which costs incurred by it and its affiliates are reimbursable by us;

§ our general partner is allowed to resolve any conflicts of interest involving us and our general partner and its affiliates, and may take into account the interests of parties other than us, such as EPCO, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;

§ any resolution of a conflict of interest by our general partner not made in bad faith and that is fair and reasonable to us is binding on the partners and is not a breach of our partnership agreement;

§ affiliates of our general partner may compete with us in certain circumstances;

§ our general partner has limited its liability and reduced its fiduciary duties and has also restricted the remedies available to our unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. As a result of purchasing our units, you are deemed to consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;

§ we do not have any employees and we rely solely on employees of EPCO and its affiliates;

§ in some instances, our general partner may cause us to borrow funds in order to permit the payment of distributions;

§ our general partner may cause us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

§ our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, may be entitled to be indemnified by us;

§ our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and

§ our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

We have significant business relationships with entities controlled by EPCO and Dan Duncan LLC. For information regarding these relationships and related party transactions with EPCO and its affiliates, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. Additional information regarding our relationship with EPCO and its affiliates can be found under Item 13 of this annual report.

Unitholders have limited voting rights and are not entitled to elect our general partner or its directors. In addition, even if unitholders are dissatisfied, they cannot easily remove our general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or its directors and will have no right to elect our general partner or its directors on an annual or other continuing basis. The owners of our general partner choose the directors of our general partner.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have no practical ability to remove our general partner or its officers or directors. Our general partner may not be removed except upon the vote of the holders of at least 60% of our outstanding units voting together as a single class. Since affiliates of our general partner currently own approximately 37.9% of our outstanding common units and 100% of our Class B Units, the removal of Enterprise GP as our general partner is highly unlikely without the consent of both our general partner and its affiliates. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence of a takeover premium in the trading price.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by a provision in our partnership agreement stating that any units held by a person that owns 20% or more of any class of our common units then outstanding, other than our general partner and its affiliates, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders' ability to influence our management. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence of a takeover premium in the trading price.

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

If at any time our general partner and its affiliates own 85% or more of the common units then outstanding, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price not less than the then current market price. As a result, common unitholders may be required to sell their common units at an undesirable time or price and may therefore not receive any return on their investment. They may also incur a tax liability upon the sale of their common units.

Our common unitholders may not have limited liability if a court finds that limited partner actions constitute control of our business.

Under Delaware law, common unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right of limited partners to remove our general partner or to take other action under our partnership agreement constituted participation in the "control" of our business. Under Delaware law, our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those of our contractual obligations that are expressly made without recourse to our general partner.

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The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business. You could have unlimited liability for our obligations if a court or government agency determined that (i) we were conducting business in a state, but had not complied with that particular state's partnership statute; or (ii) your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constituted "control" of our business.

Unitholders may have liability to repay distributions.

Under certain circumstances, our unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of common units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to such purchaser of common units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from our partnership agreement.

Our general partner's interest in us and the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner, in accordance with our partnership agreement, may transfer its general partner interest without the consent of unitholders. In addition, our general partner may transfer its general partner interest to a third party in a merger or consolidation or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the sole member of our general partner, currently Dan Duncan LLC, to transfer its equity interests in our general partner to a third party. The new equity owner of our general partner would then be in a position to replace the Board of Directors and officers of our general partner with their own choices and to influence the decisions taken by the Board of Directors and officers of our general partner.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service were to treat us as a corporation for federal income tax purposes or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends, to an extent, on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service ("IRS") on this matter.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate (which is currently at a maximum of 35%) and we would also likely pay additional state income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distribution to our unitholders would be substantially reduced. Thus, treatment of us as a corporation would result in a material reduction in the after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to a material amount of entity level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to enhance state-tax collections. If any additional state were to impose an entity-level tax upon us or our operating subsidiaries, the cash available for distribution to our unitholders would be reduced.

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

The present federal income tax treatment of publicly traded partnerships, including us, may be modified by administrative, legislative or judicial interpretation at any time. Any modification to federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the qualifying income exception in order for us to be treated as a partnership for federal income tax purposes (i.e., not taxable as a corporation). In addition, such changes may affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income, or otherwise adversely affect an investment in our common units. The Obama Administration and certain members of Congress have recently considered substantive changes to existing federal income tax laws that would adversely affect the tax treatment of certain types of publicly traded partnerships. We are unable to predict whether any of these changes or any other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units and the amount of cash available for distribution to our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We prorate items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of the units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units and the cost of any IRS contest will reduce our cash available for distribution to unitholders.

The IRS may adopt positions that differ from the positions we take, even positions taken with advice of counsel. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may adversely impact the taxable income reported to our unitholders and the income taxes they are required to pay. As a result, any such contest with the IRS may materially and adversely impact the market for our common units and the price at which our common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our unitholders.

Even if our common unitholders do not receive any cash distributions from us, they will be required to pay taxes on their share of our taxable income.

Because our unitholders will be treated as partners to whom we will allocate taxable income (which could be different in amount from the cash that we distribute), our unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive any cash distributions from us. Our common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting from their share of our taxable income.

Tax gain or loss on the disposition of our common units could be different than expected.

If a common unitholder sells common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized in the sale and the unitholder's tax basis in those common units. Prior distributions to a unitholder in excess of the total net taxable income a unitholder is allocated for a common unit,

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which decreased the unitholder's tax basis in that common unit, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price the unitholder receives is less than the unitholder's original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to a unitholder. In addition, because the amount realized may include a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of the cash received from the sale.

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

Investments in our common units by tax-exempt entities, such as individual retirement accounts ("IRAs"), other retirement plans and non-U.S. persons, raise issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income.

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

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

Our common unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of an investment in our common units.

In addition to federal income taxes, our common unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property even if the unitholder does not live in any of those jurisdictions. Our common unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, they may be subject to penalties for failure to comply with those requirements. We may own property or conduct business in other states or foreign countries in the future. It is the responsibility of each unitholder to file its own federal, state and local tax returns.

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

We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which could result in us filing two tax returns (and our unitholders could receive two Schedule K-1s) for one fiscal year. A technical termination could also result in the deferral of depreciation deductions allowable in computing our taxable income.

The IRS has recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership will be required to provide only a single Schedule K-1 to unitholders for the tax year in which the technical termination occurs.

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

Because a common unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

Item 1B. Unresolved Staff Comments.

None.

Item 3. Legal Proceedings.

As part of our normal business activities, we may be named as defendants in litigation and legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. Except as described below, as of February 29, 2012, we are not aware of any material pending legal proceedings, other than routine litigation incidental to our business, to which we are a party. For more information regarding our litigation matters, see "—Litigation Matters" under Note 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report, which subsection is incorporated by reference into this Item 3.

On occasion, we are assessed monetary sanctions by governmental authorities related to administrative or judicial proceedings involving environmental matters. The following is a discussion of such matters where the amount of monetary sanctions sought is in excess of $100,000. We do not believe that any expenditures related to such matters will be material to our financial statements.

§ In March 2007, a segment of our Mid-America Pipeline System was struck by a third party in Nebraska causing a release of 1,725 barrels of natural gasoline. In April 2010, another segment of our Mid-America Pipeline System ruptured as a result of historical damage to the pipeline, which resulted in the release of 1,669 barrels of natural gasoline. Furthermore, in August 2011, flooding on the Missouri river caused the release of 818 barrels of natural gasoline from a segment of the Mid-America Pipeline System. We are in contact with various federal and state governmental authorities regarding these releases, including the U.S. Department of Justice and EPA. We believe that the eventual resolution of these matters will result in penalties and other costs exceeding $0.1 million.

§ After concluding an internal audit in 2011, we contacted the New Mexico Environment Department to self-disclose possible air emission and permit compliance violations at our facilities located in New Mexico. We believe that the eventual resolution of these matters will result in penalties and other costs exceeding $0.1 million.

§ In the third quarter of 2011, we received three compliance orders from the Colorado Department of Public Health and Environment in connection with alleged violations of air pollution regulations and related permit requirements in 2008, 2009 and 2010 at our facilities located in Colorado. We believe that the

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eventual resolution of these Colorado matters will result in penalties and other costs approximating $1.1 million.

- In the fourth quarter of 2011, certain of our subsidiaries were named by the EPA as a potentially responsible party in connection with the U.S. Oil Recovery Superfund Site located in Pasadena, Texas. We believe that the eventual resolution of these matters will result in penalties and other costs exceeding $0.1 million.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

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

Market Information and Cash Distributions for Enterprise

Our common units are listed on the NYSE under the ticker symbol "EPD." As of February 1, 2012, there were approximately 2,800 unitholders of record of our common units. The following table presents the high and low sales prices for our common units during the periods presented (as reported by the NYSE Composite Transaction Tape) and the amount, record date and payment date of the quarterly cash distributions we paid on each of our common units with respect to such periods. Actual cash distributions are paid by us within 45 days after the end of each fiscal quarter.

	Price Ranges		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2010					
1st Quarter	$34.69	$29.44	$0.5675	April 30, 2010	May 6, 2010
2nd Quarter	$36.73	$29.05	$0.5750	July 30, 2010	August 5, 2010
3rd Quarter	$39.69	$34.21	$0.5825	October 29, 2010	November 8, 2010
4th Quarter	$44.32	$39.26	$0.5900	January 31, 2011	February 7, 2011
2011					
1st Quarter	$44.35	$27.85	$0.5975	April 29, 2011	May 6, 2011
2nd Quarter	$43.95	$38.67	$0.6050	July 29, 2011	August 10, 2011
3rd Quarter	$43.95	$36.36	$0.6125	October 31, 2011	November 9, 2011
4th Quarter	$46.70	$38.01	$0.6200	January 31, 2012	February 9, 2012

We expect to fund our quarterly cash distributions primarily with cash provided by operating activities. Although the payment of cash distributions is not guaranteed, we expect to continue to pay comparable cash distributions in the future as those presented in the preceding table.

As discussed under "Noncontrolling Interests" within Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report, the cash distributions paid by Enterprise to its limited partners other than Holdings prior to the Holdings Merger in November 2010 are a component of noncontrolling interests. For additional information regarding our cash flows from operating activities, see "Liquidity and Capital Resources" included under

Item 7 of this annual report.

Recent Sales of Unregistered Securities

There were no sales of unregistered equity securities during 2011.

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Common Units Authorized for Issuance Under Equity Compensation Plan

See "Securities Authorized for Issuance Under Equity Compensation Plans" under Item 12 of this annual report, which is incorporated by reference into this Item 5.

Issuer Purchases of Equity Securities

In December 1998, we announced a common unit repurchase program whereby we, together with certain affiliates, intended to repurchase up to 2,000,000 of our common units for the purpose of granting options to management and key employees (amount adjusted for the 2-for-1 unit split in May 2002). We have not repurchased any of our common units under this program since 2002. As of February 1, 2012, we and our affiliates could repurchase up to 618,400 additional common units under this repurchase program.

During the year ended December 31, 2011, 936,608 restricted common unit and similar unit awards granted to employees of EPCO vested and were converted to common units. Of this amount, 255,276 were sold back to us by the employees to cover their related withholding tax requirements. The total cost of these treasury units was approximately $10.7 million. We cancelled such treasury units immediately upon acquisition. The following table summarizes our repurchase activity during 2011 in connection with these vesting transactions:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
February 2011 (1)	91,126	$ 43.00	--	--
May 2011 (2)	135,475	$ 41.63	--	--
August 2011 (3)	14,831	$ 38.62	--	--
November 2011 (4)	13,844	$ 44.44	--	--

(1) Of the 336,227 restricted common units that vested in February 2011 and converted to common units, 91,126 units were sold back to us by employees to cover related withholding tax requirements.
(2) Of the 492,318 restricted common units that vested in May 2011 and converted to common units, 135,475 units were sold back to us by employees to cover related withholding tax requirements.
(3) Of the 57,963 restricted common units that vested in August 2011 and converted to common units, 14,831 units were sold back to us by employees to cover related withholding tax requirements.
(4) Of the 50,100 restricted common units and similar unit awards that vested in November 2011 and converted to common units, 13,844 units were sold back to us by employees to cover related withholding tax requirements.

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Item 6. Selected Financial Data.

The following table presents selected historical consolidated financial data of our partnership. As a result of the Holdings Merger, our consolidated financial and operating results prior to November 22, 2010 have been presented as if we were Holdings from an accounting perspective. This information has been derived from and should be read in conjunction with the audited financial statements included under Item 8 of this annual report. Additional information regarding our results of operations and liquidity and capital resources can be found under Item 7 of this annual report. As presented in the table, amounts are in millions (except per unit data).

	For Year Ended December 31,				
	2011	2010	2009	2008	2007
Results of operations data: (1)					
Revenues	$44,313.0	$33,739.3	$25,510.9	$35,469.6	$26,713.8
Income from continuing operations	$2,088.3	$1,383.7	$1,140.3	$1,145.1	$762.0
Net income	$2,088.3	$1,383.7	$1,140.3	$1,145.1	$762.0
Net income attributable to partners	$2,046.9	$320.8	$204.1	$164.0	$109.0
Earnings per unit: (2)					
Basic	$2.48	$1.17	$0.99	$0.89	$0.65
Diluted	$2.38	$1.15	$0.99	$0.89	$0.65
Other financial data:					
Cash distributions per unit (3)	$2.44	$2.27	$2.03	$1.79	$1.55

	As of December 31,				
	2011	2010	2009	2008	2007
Financial position data: (1)					
Total assets	$34,125.1	$31,360.8	$27,686.3	$25,780.4	$24,084.4
Long-term debt, including current maturities (4)	$14,529.4	$13,563.5	$12,427.9	$12,714.9	$9,861.2
Equity (5)	$12,219.3	$11,900.8	$10,473.1	$9,759.4	$9,530.0
Total units outstanding (6)	881.6	843.7	208.8	184.8	168.5

(1) In general, our consolidated results of operations and financial position have been impacted by our capital spending program, including business combinations. For information regarding our capital spending program, see "Liquidity and Capital Resources – Capital Spending" under Item 7 of this annual report.
(2) Earnings per unit amounts for periods prior to the Holdings Merger have been retroactively presented to reflect the 1.5 to one unit-for-unit exchange that occurred under the Holdings Merger. For information regarding our earnings per unit amounts, see Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.
(3) Cash distributions per unit for 2009, 2008 and 2007 reflect those declared and paid by Holdings. Cash distributions per unit presented for 2010 represent the sum of cash distributions declared and paid by Holdings with respect to the first, second and third quarters of 2010 and the cash distribution declared and paid by Enterprise with respect to the fourth quarter of 2010. Cash distributions per unit for 2011 represent those declared and paid by Enterprise with respect to the first, second, third and fourth quarters of 2011. For information regarding our cash distributions, see Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.
(4) Consolidated debt has increased over time as a result of our capital spending program. For information regarding our consolidated debt obligations, see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. For information regarding our capital spending program, see "Liquidity and Capital Resources—Capital Spending" under Item 7 of this annual report.

(5) Consolidated equity has increased over time primarily due to the issuance of limited partner units by Enterprise in connection with acquisitions and other capital spending activities. For information regarding our consolidated equity, see Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.
(6) Total limited partner units outstanding increased in 2010 in part as a result of the Holdings Merger and reflects, following the Holdings Merger, the number of Enterprise limited partner common units outstanding. Total common units outstanding increased in 2011 in part as a result of the Duncan Merger and reflects, following the Duncan Merger, the number of Enterprise common units outstanding. Total units outstanding includes the Designated Units issued in connection with the Holdings Merger and owned by a privately held affiliate of EPCO that agreed to temporarily waive regular quarterly cash distributions over a five-year period. See "Liquidity and Capital Resources—Designated Units Issued in Connection with the Holdings Merger" under Item 7 of this annual report. Total units outstanding at December 31, 2011 and 2010 exclude 4.5 million Class B units of Enterprise.

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

For the Years Ended December 31, 2011, 2010 and 2009

The following information should be read in conjunction with our Consolidated Financial Statements and accompanying notes included under Item 8 of this annual report. Our financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States ("U.S.").

Key References Used in this Management's Discussion and Analysis

Unless the context requires otherwise, references to "we," "us," "our," "Enterprise" or "Enterprise Products Partners" a intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. References to "EPO" mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise, and its consolidated subsidiaries, through which Enterprise Products Partners L.P. conducts its business. Enterprise is managed by its general partner, Enterprise Products Holdings LLC ("Enterprise GP"), which is a wholly owned subsidiary of Dan Duncan LLC, a Delaware limited liability company.

On September 3, 2010, Enterprise GP Holdings L.P. ("Holdings"), Enterprise, Enterprise GP, Enterprise Products GP, LLC ("EPGP," the former general partner of Enterprise) and Enterprise ETE LLC ("Holdings MergerCo," a Delaware limited liability company and a wholly owned subsidiary of Enterprise) entered into a merger agreement (the "Holdings Merger Agreement"). On November 22, 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with and into Holdings MergerCo and related transactions were completed, with Holdings MergerCo surviving such merger (collectively, we refer to these transactions as the "Holdings Merger"). Enterprise's membership interests in Holdings MergerCo were subsequently contributed to EPO. As a result of completing the Holdings Merger, Enterprise GP, which had previously been the general partner of Holdings ("Holdings GP"), became Enterprise's general partner. For additional information regarding the Holdings Merger, see Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The membership interests of Dan Duncan LLC are owned of record by a voting trust, the current trustees ("DD LLC Trustees") of which are: (i) Randa Duncan Williams, who is also a director of Enterprise GP; (ii) Dr. Ralph S. Cunningham, who is also a director and the Chairman of Enterprise GP; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP. Each of the DD LLC Trustees also currently serves as one of the three managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust, the current trustees ("EPCO Trustees") of which are: (i) Ms. Williams, who also serves as Chairman of EPCO; (ii) Dr. Cunningham, who also serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who also serves as the President and Chief Executive Officer ("CEO") of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also directors of EPCO.

On April 28, 2011, we, our general partner, EPD MergerCo LLC ("Duncan MergerCo," a Delaware limited liability company and our wholly owned subsidiary), Duncan Energy Partners L.P. ("Duncan Energy Partners") and DEP Holdings, LLC ("DEP GP," the general partner of Duncan Energy Partners) entered into a definitive merger agreement (the "Duncan Merger Agreement"). On September 7, 2011, the Duncan Merger Agreement was approved by the unitholders of Duncan Energy Partners and the merger of Duncan MergerCo with and into Duncan Energy Partners and related transactions were completed, with Duncan Energy Partners surviving such merger as our wholly owned subsidiary (collectively, we refer to these transactions as the "Duncan Merger"). For additional information regarding the Duncan Merger, see Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

References to “TEPPCO” and “TEPPCO GP” mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their mergers with our subsidiaries on October 26, 2009. We refer to such related mergers both individually and in the aggregate as the “TEPPCO Merger.”

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References to “Employee Partnerships” mean EPE Unit L.P., EPE Unit II, L.P., EPE Unit III, L.P., Enterprise Unit L.P. and EPCO Unit L.P., collectively, all of which were privately held affiliates of EPCO. The Employee Partnerships were liquidated in August 2010.

As generally used in the energy industry and in this annual report, the acronyms below have the following meanings:

/d	= per day	MMBbls	= million barrels
BBtus	= billion British thermal units	MMBPD	= million barrels per day
Bcf	= billion cubic feet	MMBtus	= million British thermal units
BPD	= barrels per day	MMcf	= million cubic feet
MBPD	= thousand barrels per day	TBtus	= trillion British thermal units

Cautionary Statement Regarding Forward-Looking Information

This discussion contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as “anticipate,” “project,” “expect,” “plan,” “seek,” “goal,” “estimate,” “forecast,” “intend,” “co “will,” “believe,” “may,” “potential” and similar expressions and statements regarding our plans and objectives for future operations are intended to identify forward-looking statements. Although we and our general partner believe that our expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions as described in more detail under Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this annual report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

Overview of Business

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange (“NYSE”) under the ticker symbol “EPD.” We were formed in April 1998 to own and operate certain natural gas liquids (“NGLs”) related businesses of EPCO and are now a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the U.S., Canada and the Gulf of Mexico with domestic consumers and international markets. Our assets include approximately 50,600 miles of onshore and offshore pipelines; 190 MMBbls of storage capacity for NGLs, crude oil, refined products and certain petrochemicals; and 14 Bcf of working natural gas storage capacity.

Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminaling; crude oil and refined products transportation, storage, and terminaling; offshore production platforms; petrochemical transportation and services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. We have six reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; (v) Petrochemical & Refined Products Services; and (vi) Other Investments.

We conduct substantially all of our business through EPO and are owned 100% by our limited partners from an economic perspective. Enterprise GP owns a non-economic general partner interest in us.

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Significant Recent Developments

Development of Our ATEX Express Long-Haul Ethane Pipeline

In January 2012, we announced the receipt of sufficient transportation commitments to support development of our 1,230-mile Appalachia to Texas pipeline (the "ATEX Express") that will transport growing ethane production from the Marcellus and Utica Shale producing areas of Pennsylvania, West Virginia and Ohio to the U.S. Gulf Coast. Demand for ethane feedstock over more expensive crude oil-based derivatives within the Gulf Coast petrochemical market has reached over 1 MMBPD and continues to increase given current pricing differentials. Several petrochemical companies have made announcements to modify, expand or build new facilities that would use ethane as a feedstock. As currently designed, the ATEX Express will have the capacity to transport up to 190 MBPD of ethane from the Appalachian production areas to our storage and distribution assets in southeast Texas.

The project would utilize a combination of new and existing infrastructure. The northern portion of the ATEX Express involves construction of a pipeline that would originate in Pennsylvania and extend west, then southwest, to Indiana following existing pipeline corridors in order to minimize the footprint of the project. The southern portion of ATEX Express would utilize a significant portion of our existing Products Pipeline System, which would be reversed to accommodate southbound delivery of ethane to the U.S. Gulf Coast. At the southern terminus of the ATEX Express in Beaumont, we plan to construct a 55-mile pipeline to provide shippers with access to our NGL storage complex at Mont Belvieu, which would provide them with direct and indirect access to every ethylene plant in the U.S. We expect that the ATEX Express will begin commercial operations in the first quarter of 2014.

Plans to Construct a Crude Oil Pipeline in the Gulf of Mexico with Genesis

In January 2012, we announced the execution of crude oil transportation agreements with a consortium of six Gulf of Mexico producers that will provide the necessary support for construction of a crude oil gathering pipeline serving the Lucius oil and gas field located in the southern Keathley Canyon area of the deepwater central Gulf of Mexico. The pipeline will be constructed and owned by Southeast Keathley Canyon Pipeline Company, L.L.C. ("SEKCO"), which is a 50/50 joint venture owned by us and Genesis Energy, L.P. ("Genesis"). We will serve as construction manager and operator of the new deepwater pipeline (the "SEKCO Oil Pipeline").

The 149-mile, 18-inch diameter SEKCO Oil Pipeline is being designed with a crude oil transportation capacity of 115 MBPD and would connect the third party owned Lucius-truss spar floating production platform to an existing junction platform at South Marsh Island 205 that is part of our Poseidon Oil Pipeline System. The Lucius production area is estimated to have more than 300 MMBbls of oil equivalent, with relatively shallow and highly productive reservoirs, primarily comprised of crude oil. The SEKCO Oil Pipeline is expected to begin service by mid-2014.

Sale of 22.8 Million Common Units of Energy Transfer Equity

In January 2012, we sold 22,762,636 common units of Energy Transfer Equity, L.P. ("Energy Transfer Equity") in a private transaction, which generated cash proceeds of approximately $825.1 million. Proceeds from this sale were used for general company purposes, including funding capital expenditures. Our Other Investments business segment consists of our investment in the common units of Energy Transfer Equity. As of the date of this report, we own approximately 6 million common units of Energy Transfer Equity, which represent less than 3% of its common units outstanding at February 15, 2012.

Plans with Enbridge to Reverse the Seaway Pipeline

In November 2011, ConocoPhillips agreed to sell its 50% partnership interest in Seaway Crude Pipeline Company ("Seaway") to Enbridge Inc. ("Enbridge"). This transaction closed in December 2011. We own the remaining 50% partnership interest in Seaway, which owns the Seaway crude oil pipeline system (the "Seaway pipeline"), and operate the Seaway pipeline. Historically, the 546-mile Seaway pipeline transported imported crude oil from Freeport, Texas to the Cushing, Oklahoma hub. The increase in crude oil production from Canada's tar

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sands and U.S. fields like the Bakken in North Dakota and Niobrara in Kansas, Wyoming and Colorado, has led to an oversupply of oil at the Cushing hub. This oversupply at Cushing led to depressed prices for domestic crude oil production versus international and U.S. Gulf Coast benchmarks, which, in turn, created feedstock cost disadvantages for domestic refiners that rely primarily on imported crude oil. As a result of the change in ownership in Seaway, we and Enbridge Inc. agreed to reverse the direction of crude oil flows on the Seaway pipeline to enable it to transport oil from the oversupplied Cushing hub to U.S. Gulf Coast refiners.

Pending regulatory approval, the Seaway pipeline could operate in reversed service with an initial capacity of 150 MBPD during the second quarter of 2012. Following pump station additions and other modifications, which are anticipated to be completed in the first quarter of 2013, we anticipate the capacity of the reversed Seaway pipeline will be up to 400 MBPD (assuming a mix of light and heavy grades of crude oil). We expect that this capacity will be fully contracted by shippers. In anticipation of additional shipper demand, we launched an open season in January 2012 to support a further expansion of the Seaway pipeline's transportation capacity.

The reversed Seaway pipeline will deliver crude oil from Cushing into the Houston, Texas market by utilizing affiliate and third party pipelines. Seaway plans to build a 45-mile pipeline that will link its pipeline to our Enterprise Crude Houston ("ECHO") crude oil storage terminal, which is being constructed southeast of Houston. Completion of this pipeline segment is expected in the first quarter of 2013. In addition, Seaway plans to build an 85-mile pipeline from our ECHO facility to the Port Arthur/Beaumont, Texas refining center that would provide shippers access to the region's heavy oil refining capabilities. Completion of this pipeline segment is expected in early 2014.

Expansion of Our Natural Gas Pipeline and Processing Infrastructure in the Eagle Ford Shale

In November 2011, we announced several new construction projects that would extend and expand our natural gas and NGL infrastructure in South Texas to accommodate expected production growth from the Eagle Ford Shale. As a result of additional demand from our Eagle Ford Shale producing customers, along with the execution of new gathering and processing agreements, we plan to expand natural gas processing capacity at our Yoakum facility (which is currently under construction) by an additional 300 MMcf/d. Once the expansion is completed, we expect our Yoakum facility will have total gas processing capacity of 900 MMcf/d. We also plan to increase the size of the NGL takeaway pipelines originating at the Yoakum plant to handle the expected increase in NGL production. We expect the Yoakum facility to commence operations in phases with the first 300 MMcf/d to be available by May 2012, the second 300 MMcf/d coming online in July 2012, and the third 300 MMcf/d to be available by February 2013. The new Yoakum plant will complement our seven existing natural gas processing plants in South Texas, which currently have the capacity to process approximately 1.5 Bcf/d.

In addition to the Yoakum expansion, we are constructing 62 miles of natural gas pipeline loops and increasing compression to gather and transport an additional 300 MMcf/d of liquids-rich Eagle Ford Shale natural gas. These pipeline expansion projects are also expected to begin service in the first quarter of 2013.

Start of Service on Our Acadian Haynesville Extension

In November 2011, commercial operations on the Haynesville Extension of our Acadian Gas System commenced. As a result of completing the Haynesville Extension project, we have provided producers in Louisiana's Haynesville and Bossier Shale plays with access to 1.8 Bcf/d of incremental natural gas takeaway capacity. As an extension of our Acadian Gas System, the Haynesville Extension offers producers access to more than 150 end-user customer service locations along the Mississippi River industrial corridor between Baton Rouge and New Orleans, as well as the Henry Hub. The Haynesville Extension features interconnects with twelve interstate pipeline systems and is the only southerly option that avoids potential natural gas supply bottlenecks at the Perryville Hub and offers producers flow assurance and market choice to assist in maximizing the value of their natural gas.

Sale of Our Mississippi Natural Gas Storage Facilities

In October 2011, we announced the execution of definitive agreements to sell our ownership interests in Crystal Holding L.L.C. (“Crystal”) to Boardwalk HP Storage Company, LLC for $550 million in cash, before

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working capital adjustments of $2.2 million. The transaction closed in December 2011 and we recorded a gain of $129.1 million on the sale. Crystal owns two underground salt dome natural gas storage facilities located near Petal and Hattiesburg, Mississippi having approximately 29 Bcf of total storage capacity and related pipelines. Proceeds from this sale were used for general company purposes, including the funding of capital expenditures.

Crystal's operations were a component of our Onshore Natural Gas Pipelines & Services business segment. We have determined that Crystal's operations do not meet the criteria to be classified as discontinued operations. Following the sale, we continue to have significant commercial contracts and operational arrangements at the Petal and Hattiesburg facilities, which are adjacent to and currently share operating assets with our retained Petal, Mississippi NGL storage facility.

Completion of the Duncan Merger

In September 2011, the Duncan Merger Agreement was approved by the unitholders of Duncan Energy Partners and the merger of Duncan MergerCo and Duncan Energy Partners and related transactions were completed, with Duncan Energy Partners surviving such merger as our wholly owned subsidiary. Each issued and outstanding common unit of Duncan Energy Partners was cancelled and converted into the right to receive our limited partner common units based on an exchange ratio of 1.01 Enterprise common units for each Duncan Energy Partners common unit. We issued 24,277,310 of our common units (net of fractional common units cashed out) to the former public unitholders of Duncan Energy Partners as consideration in the Duncan Merger. We did not issue any common units as merger consideration to our subsidiaries that owned limited partner interests in Duncan Energy Partners.

Development of the Texas Express Pipeline with Enbridge and Anadarko

In September 2011, we, along with Enbridge Energy Partners, L.P. ("Enbridge") and Anadarko Petroleum Corporation ("Anadarko"), announced an agreement to design and construct a new NGL pipeline (the "Texas Express Pipeline") that would originate in Skellytown, Texas and extend approximately 580 miles to NGL fractionation and storage facilities in Mont Belvieu, Texas. NGL volumes from the Rocky Mountains, Permian Basin and Mid-continent regions will be delivered to the Texas Express Pipeline through an interconnect with the Conway South segment of our Mid-America Pipeline System. The Texas Express Pipeline will help producers in West and Central Texas, the Rocky Mountains, Southern Oklahoma and the Mid-continent to maximize the value of their NGL production by providing additional takeaway capacity and enhanced access to the U.S. Gulf Coast NGL market. Initial transportation capacity on the Texas Express Pipeline is expected to be approximately 250 MBPD, which could be expanded to approximately 400 MBPD. The new pipeline will be constructed and owned by Texas Express Pipeline LLC, the membership interests of which are held by us (45% share), Enbridge (35% share) and Anadarko (20% share). We will serve as construction manager and operator of the Texas Express Pipeline.

In addition, the joint venture plans to construct and own two new NGL gathering systems. The first NGL gathering system will connect the Texas Express Pipeline to natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and Western Oklahoma. The second NGL gathering system will connect the new pipeline to Barnett Shale gas processing plants located in Central Texas. Enbridge will serve as construction manager and operator of these NGL gathering systems. Subject to regulatory approvals, the Texas Express Pipeline and related NGL gathering systems are expected to begin service in the second quarter of 2013.

Plans to Build a Sixth NGL Fractionator at Our Mont Belvieu Complex

In June 2011, we announced plans to construct a sixth NGL fractionator at our Mont Belvieu, Texas facility. The new fractionation facility will have a nameplate capacity of 75 MBPD and accommodate NGLs from the continued growth of liquids-rich natural gas production from the Eagle Ford Shale and other producing areas. We have started construction of the new fractionator, and we expect it to begin service in late 2012.

In October 2011, commercial operations at our fifth NGL fractionator at Mont Belvieu commenced. This new fractionator increases the total nameplate NGL fractionation capacity at our Mont Belvieu facility to 380 MBPD. When our sixth Mont Belvieu NGL fractionator is completed, we will have the capability to fractionate

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more than 450 MBPD of NGLs at our Mont Belvieu complex and our system-wide net fractionation capacity will increase to approximately 770 MBPD.

Expansion of Our South Texas Crude Oil Pipeline System

In May 2011, we announced plans to build an 80-mile extension of our South Texas Crude Oil Pipeline System (the “Phase II project”), which would allow us to serve growing production areas in the southwestern portion of the Eagle Ford Shale supply basin. The Phase II project, which is being designed with a crude oil transportation capacity of 200 MBPD, will originate at Lyssy, Texas (at the terminus of our previously announced 140-mile Phase I segment) and extend to Gardendale, Texas, where a new central delivery point is planned for construction that will feature 0.5 MMBbls of crude oil storage. The system’s Phase I pipeline expansion project, which is expected to have a crude oil transportation capacity of 350 MBPD, originates at Sealy, Texas and extends to Lyssy, Texas. Phase I of the expansion project includes construction of 2.4 MMBbls of crude oil storage along the new pipeline, including 0.6 MMBbls at Lyssy, Texas, 0.2 MMBbls at Milton, Texas, 0.4 MMBbls at Marshall, Texas, and 1.2 MMBbls at Sealy, Texas.

Phase I of the project is forecast to begin service by the second quarter of 2012, with Phase II set to commence operations in the first quarter of 2013. When completed, the approximately 220-miles of additional crude oil pipelines are expected to provide Eagle Ford Shale producers with access to the Texas Gulf Coast refining complex through our integrated midstream asset network, including our ECHO crude oil terminal which is under construction. The ECHO terminal will provide shippers with access to major refiners located in the Houston and Texas City, Texas refining hub representing more than 2 MMBPD of refining capacity. The ECHO terminal will also have connections to marine facilities which will provide connectivity to any refinery on the U.S. Gulf Coast. The ECHO facility is scheduled to begin service in mid-2012 and will initially have 0.8 MMBbls of crude oil storage capacity. In February 2012, we announced an expansion of our ECHO facility, which will provide capability to increase its crude oil storage capacity to approximately 6 MMBbls.

Expansion of Our Propylene Fractionation Capacity at Mont Belvieu

In May 2011, we announced plans to expand our Mont Belvieu polymer grade propylene (“PGP”) fractionation facility to accommodate increased PGP demand. When completed, the expansion project will increase our net capacity to produce PGP by more than 10% from 73 MBPD (approximately 4.9 billion pounds per year) to 80.5 MBPD (approximately 5.4 billion pounds per year). The expansion is expected to be in service in the first quarter of 2013.

To produce PGP, which is approximately 99.5% pure propylene, we fractionate refinery grade propylene (“RGP”), which is approximately 60% to 65% propylene, with the remainder being propane and butane. The demand for PGP primarily relates to the manufacture of polypropylene, which has a variety of end uses including packaging film, fiber for carpets and upholstery, and molded plastic parts for appliances, automotive, houseware and medical products. Since 2000, demand for PGP has increased by 20%; however, the supply of PGP produced as a co-product from the cracking of crude oil derivatives in the production of ethylene has declined approximately 40%. This decline is attributable to ethylene producers using more NGLs, such as ethane and propane, as feedstocks instead of more costly crude oil derivatives.

We have an extensive integrated propylene infrastructure system that complements the expansion project. Through our Texas City RGP Gathering System, which connects to 13 refineries in the Houston, Texas area, as well as marine, rail and truck transportation capabilities at our Mont Belvieu complex, we can receive supplies of RGP from approximately 60 facilities across North America. On the delivery side, we connect to 17 consumers of PGP. We also have the only operating PGP export terminal in the U.S. located in Seabrook, Texas. This export facility enables us to provide PGP to growing international markets.

Expansion of Our Houston Ship Channel Import/Export Terminal

In March 2011, we announced an expansion of our primary Houston Ship Channel import/export terminal. This expansion project is expected to nearly double the terminal's fully refrigerated export loading capacity for propane and other NGLs to more than 10,000 barrels per hour, while enhancing the terminal's ability to load multiple vessels simultaneously. We expect to complete this expansion project in the second half of 2012.

Expansion of Our Mid-America Pipeline System in the Rocky Mountains

In March 2011, we announced an expansion project involving the Rocky Mountain segment of our Mid-America Pipeline System. The 2,932-mile Rocky Mountain pipeline transports mixed NGLs from the Rocky Mountain Overthrust and San Juan Basin areas to our Hobbs NGL fractionation facility located in Gaines County, Texas. At the Hobbs facility, the Mid-America Pipeline System links to our Seminole Pipeline, which enables shippers access to the world's largest NGL fractionation complex at Mont Belvieu, Texas, including facilities owned and operated by us.

The Rocky Mountain pipeline expansion involves looping the existing system with approximately 218 miles of 16-inch diameter pipeline, as well as pump station modifications. This expansion project is expected to add 62.5 MBPD of transportation capacity to the Rocky Mountain pipeline's existing capacity of approximately 275 MBPD (after taking into account shipper commitments announced in January 2012). The additional capacity is designed to handle growing natural gas and NGL production from major supply basins in Utah, Colorado, Wyoming and New Mexico. Several new natural gas processing plants are being constructed in the Uinta, Piceance and Greater Green River basins that will fill the expansion, which is expected to begin service in the third quarter of 2014. Additionally, the Rocky Mountain expansion project complements our Texas Express Pipeline joint venture, and enhances the growth opportunities of our integrated processing, pipeline, storage, fractionation and distribution network.

Incident at Our Mont Belvieu West Storage Facility

In February 2011, we experienced an NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. West Storage consists of ten underground salt dome storage caverns with a storage capacity of approximately 15 MMBbls. Through the reconfiguration of product receipt and delivery capabilities and other measures, we readily returned our Mont Belvieu plants and related assets to close to the same capabilities as we had prior to the incident; however, our West Storage location and associated underground storage wells remain partially inoperative at this time. Remaining repairs to this location are underway and are expected to be completed in stages by mid-2012.

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other insurance coverage, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. Our deductible for this incident was $5 million. We remain in negotiation with our insurance carriers regarding the overall claim, which is currently projected to be at least $150 million. As non-refundable insurance proceeds are received, we expect to record gains related to this incident. See Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding insurance matters.

General Outlook for 2012

Commercial Outlook

We provide midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. Factors that can affect the demand for our products and services include global and U.S. economic conditions, the market price and demand for energy, the cost to develop natural gas and crude oil reserves in the U.S., and the cost and availability of capital to energy companies to invest in exploration and production activities.

The global economic expansion that began in late 2009 continued in 2011, with all of the twenty largest developed economies ("G20"), except for Japan, reporting year-over-year growth in real gross domestic product ("GDP") for 2011. This growth appears to be continuing in early 2012. The U.S. reported modest year-over-year real GDP growth of 1.7% for 2011 compared to 2010. By comparison, the U.S. reported year-over-year real GDP growth of 3.0% for 2010 compared to 2009.

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Global demand for petroleum products continues to increase at a rate, similar to that of global economic growth, which continues to benefit from the rate of growth in developing economies. However, in the U.S. and other Organization for Economic Co-operation and Development ("OECD") countries, demand for petroleum products has declined slightly responding to higher prices, increased regulation, and improved technology. According to the U.S. Energy Information Administration, consumption of natural gas increased 3.7% for the first eleven months of 2011 versus the same period in 2010 primarily due to power generation requirements. Conversely, U.S. demand for petroleum products used for transportation purposes (e.g., motor gasoline, distillate and jet fuel) for the first eleven months of 2011 decreased by 1.7% compared to the same period of 2010.

As a result of increased global demand and geopolitical concerns, crude oil prices have continued to increase. The average prices of West Texas Intermediate ("WTI") crude oil for 2009, 2010 and 2011 were $61.88, $79.53 and $95.12 per barrel, respectively. Crude oil futures for calendar year 2012 as quoted on the New York Mercantile Exchange ("NYMEX") are currently $106.83 per barrel. In contrast, natural gas prices decreased from 2010 to 2011 primarily due to increasing shale gas production in the U.S., which has led to excess domestic natural gas supplies. For example, Henry Hub natural gas prices for 2009, 2010 and 2011 averaged $3.99, $4.39 and $4.04 per MMBtu, respectively. Henry Hub natural gas futures for calendar year 2012 as quoted on the NYMEX are currently $2.97 per MMBtu. Notably, the substantial change in the price relationship between natural gas and crude oil that began in 2009 has continued into 2012. In 2009, natural gas was priced at 37% of crude oil on an energy equivalent basis compared to 31% in 2010 and 24% in 2011. Based on NYMEX futures for 2012, natural gas is currently priced at approximately 16% relative to the price of crude oil on an energy equivalent basis.

As a result of the current relative prices of crude oil and NGLs compared to the price of natural gas, exploration and production companies are reallocating capital to increase drilling activities in shale and other non-conventional resource plays that produce crude oil and liquids-rich natural gas. Generally, producers are decreasing drilling activity in onshore areas that produce dry natural gas. This same trend is also occurring in the Gulf of Mexico, with producers investing capital to develop new sources of crude oil production rather than natural gas.

Natural gas and NGLs have had a significant feedstock price advantage over more costly crude oil derivatives (such as naphtha) and this trend is expected to continue based on prices currently quoted on the futures markets. This trend is primarily due to the following factors: (i) a decline in global crude oil excess production capacity; (ii) more government-held acreage being off limits to non-sovereign energy companies; (iii) geopolitical risk; (iv) growing demand for crude oil by China, India and other developing economies; (v) the globalization of international natural gas markets with more foreign-based liquefied natural gas liquefaction facilities becoming operational; (vi) technological breakthroughs in connection with shale resource plays in the U.S. that have decreased finding and development costs for natural gas, NGLs and crude oil; and (vii) the general inability to export natural gas from the U.S. Domestic energy producers and petrochemical companies are strategically repositioning their companies accordingly.

We believe this new trend in domestic energy production has led to a long-term structural change in feedstock selection by the domestic petrochemical industry, which is the largest consumer of NGLs. Lower feedstock costs have provided U.S. ethylene producers with a competitive global cost advantage, as ethylene crackers in Europe and Asia are mostly limited to using higher-priced naphtha feedstocks (which are priced more closely to crude oil). For 2009 through 2011, ethane and propane have been the most consistently profitable feedstocks in the production of ethylene, and are forecasted to remain so in 2012.

The production cost advantage enjoyed by U.S. petrochemical companies has led them to maximize their consumption of NGLs in the production of ethylene. Since 2009, many of these companies have expanded their operations in the U.S. and are continuing to build flexibility into their existing operations in order to increase their consumption of NGLs (as economically warranted). Even non-U.S. based ethylene crackers have responded to the NGL feedstock cost advantage by importing propane, including propane produced in the U.S., to displace crude oil derivatives such as naphtha as feedstock.

Per industry publications, domestic production of ethylene increased approximately 3.1% from 2010 to 2011. In 2011, the average ethane consumption of U.S. ethylene producers was approximately 934 MBPD, which represents an increase of 53 MBPD over 2010 levels, and we expect the trend to continue upward. According to recent industry publications, ethane demand by the domestic ethylene industry approximated 1 million barrels per day in December 2011. We believe the U.S. ethylene industry could consume approximately 250 MBPD of incremental ethane feedstocks over the next three years through modifications, expansions and debottlenecks of existing facilities. In addition, petrochemical companies have announced plans to construct additional world-scale ethylene plants in the U.S. in the coming years.

Strong end-user demand for NGLs and increases in liquids-rich natural gas production from developing shale plays such as the Eagle Ford, Uinta, Granite Wash, Marcellus and Utica Shales are expected to: (i) keep certain of our natural gas pipelines and processing plants and our NGL fractionators, pipelines, storage and export facilities operating at high utilization rates; (ii) provide attractive natural gas processing margins for our equity NGL production; and (iii) provide us with additional opportunities to invest capital to build new natural gas pipelines and processing facilities, NGL fractionation and pipeline facilities, and crude oil pipelines.

Henry Hub natural gas prices have significantly declined from a peak of over $13.00 per MMBtu in mid-2008 to less than $2.68 per MMBtu in February 2012. This price decrease has generally resulted in energy companies reallocating and, in some cases, reducing their drilling capital expenditure budgets. Natural gas drilling rig counts generally respond to changes in price and have moved down from a peak of 1,606 gas-directed rigs in 2008 to 919 at year end 2010, 809 at year end 2011 and approximately 720 in February 2012. Even though the total natural gas rig count has dropped from peak levels, the substantial efficiencies of horizontal drilling in the non-conventional and shale resource basins have allowed producers to maintain overall natural gas deliverability. As a result, rig count is not necessarily a reliable indicator of the level of future natural gas production or reserves. Because of the market prices of crude oil and NGLs, drilling activity is especially robust in shale plays containing crude oil, condensate and liquids-rich natural gas production such as the Eagle Ford, Granite Wash, Bakken and Marcellus Shales. Drilling activity in shale plays with dry natural gas production, such as the Haynesville/Bossier and Fayetteville, is down from peak levels, but remains active as certain producers are drilling to hold recently executed leases or have entered into joint ventures whereby their new joint venture partners are providing the capital to fund the development of the area for a certain period of time and for a certain dollar amount. In areas with conventional natural gas reserves, where producers typically have higher finding costs and leases are usually already held by production, rig counts generally remain significantly below peak levels.

Based on forecasted new drilling activity, the number of drilled wells waiting to be connected to our pipeline systems, and natural depletion of the associated resource basins, we believe the aggregate natural gas pipeline volumes transported on our Jonah Gathering System, Piceance Basin Gathering System and San Juan Gathering System for 2012 could range from an increase of 5% to a decrease of 5% compared to volumes transported in 2011. These areas have substantial, undeveloped non-conventional natural gas reserves (e.g., prospects to develop additional production horizons in these basins such as the Mancos and Niobrara Shales) with some of the lowest finding costs in the U.S. and are supported by existing pipeline infrastructure to transport the natural gas to market. We believe that as U.S. natural gas supply and demand becomes more balanced and natural gas prices become less volatile, these areas could experience an increase in drilling activity to support, and potentially increase, current production levels.

In the Eagle Ford Shale, which runs parallel to the Texas Gulf Coast and adjacent to our Texas Intrastate System, we have completed several pipeline projects that enable us to gather, transport and process approximately 900 MMcf/d of new natural gas production from the area. Generally, energy companies are continuing to have success in the Eagle Ford Shale and have indicated plans to accelerate their associated drilling programs. Production from this region includes crude oil, condensate, liquids-rich natural gas and dry natural gas. In 2010, we announced expansions of our natural gas pipeline, storage and processing facilities; NGL pipeline and fractionation facilities; and crude oil pipeline and storage facilities to facilitate production growth from this region. These projects represent approximately $3.0 to $3.5 billion of capital expenditures in the aggregate from 2010 through 2013.

Natural gas production from the Haynesville/Bossier Shale area of northern Louisiana has grown rapidly over the last three years and has the potential to grow even more over the next several years if natural gas prices show some recovery from their recent low levels. In November 2011, we completed construction and began commercial operations on our $1.5 billion Haynesville Extension of our Acadian Gas System. The Haynesville

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Extension is a 270-mile, 42-inch/36-inch pipeline designed to transport up to 1.8 Bcf/d of natural gas and is backed by 10-year firm fixed fee commitments from producers.

We estimate that natural gas and crude oil volumes handled by our offshore Gulf of Mexico assets will be slightly lower in 2012 compared to 2011 due to lower exploration and production activities that began in the second half of 2010 caused by federal regulatory uncertainty in the aftermath of the Deepwater Horizon oil spill. We believe crude oil volumes on our systems will increase from 2011 levels once drilling and development activities resume. Natural gas pipeline volumes may be slower to return to historical levels due to producers' allocating their capital to develop crude oil plays rather than natural gas plays due to the relative prices of these commodities. We estimate average volumes on our largest offshore asset, the Independence Hub platform and Trail pipeline will range between 350 BBtus/d and 450 BBtus/d in 2012 compared to an average of 500 BBtus/d in 2011. For the first 60 months after the Independence Hub platform went into service in March 2007, the platform has been earning a monthly demand charge of $4.6 million. This 60-month period will expire in March 2012, and this monthly demand charge will terminate. Enterprise owns 80% of the Independence Hub platform.

Our refined products pipeline systems generally serve Petroleum Administration for Defense District ("PADD") 2 of the U.S. Refinery production in PADD 2 increased by 66 MBPD in 2011 compared to 2010 due to the profit margin advantage that refiners in PADD 2 had relative to refiners on the U.S. Gulf Coast. This advantage resulted from PADD 2 refiners having the ability to utilize WTI-priced crude oil, which was priced at a substantial discount to crude oil used by refiners on the Gulf Coast (i.e., crude oil prices paid by Gulf Coast refiners are primarily based on international prices for crude oil).

Demand for refined products in PADD 2 for 2011 was approximately 4.4 MMBbls/d, which was a decrease of 1.9% compared to 2010. Our Products Pipeline System and Centennial Pipeline transport refined products produced by refineries on the Gulf Coast to be consumed in the PADD 2 region. As a result of the increased refinery production in PADD 2, demand to transport refined products to PADD 2 on our pipelines decreased. Throughput volumes to PADD 2 in 2011 on our refined products pipelines decreased by 116 MBPD to 301 MBPD. We do not expect a significant increase in demand for our refined products transportation services from the Gulf Coast to PADD 2 in 2012.

Price differentials between WTI and Brent crude oil were much wider than normal in 2011, as oil production from sources north of the Cushing hub in Oklahoma, including the Bakken Shale in North Dakota and the Canadian Oil Sands increased without adequate incremental pipeline capacity to transport them southward to markets along the Gulf Coast. These spreads reached as high as $27 per barrel in October 2011, but tightened after we and Enbridge announced their plans to reverse and expand the Seaway pipeline in November 2011 in order to move crude oil from the Midwest to the Gulf Coast. In addition to the planned Seaway pipeline reversal, a significant amount of rail capacity was added in 2011 in order to move crude southward from the producing areas and Cushing hub to refining centers. For additional information regarding the planned reversal of the Seaway pipeline, see "—Significant Recent Developments—Plans with Enbridge to Reverse the Seaway Pipeline" within this Item 7 discussion.

Liquidity Outlook

The corporate debt and equity capital markets were generally accessible in 2011. Sovereign credit markets, however, continue to be volatile due to large budget deficits being incurred by the United States, United Kingdom and many developed European countries. The cost of our term debt and equity capital generally declined and the availability of term debt and equity capital improved. Likewise, the general availability of credit commitments from most banks also improved from a year ago, except for certain investment banks and European banks, which are being impacted by their cost of capital and sovereign debt concerns.

At December 31, 2011, we had $3.37 billion of consolidated liquidity, which is defined as unrestricted cash on hand plus borrowing capacity available under our $3.5 Billion Multi-Year Revolving Credit Facility. In January 2012, we sold 22,762,636 common units of Energy Transfer Equity in a private transaction, which generated cash proceeds of approximately $825.1 million. In February 2012, we paid a quarterly cash distribution of $530.4 million to unitholders with respect to the fourth quarter of 2011. Also in February 2012, EPO issued $750.0 million in principal amount of 30-year unsecured Senior Notes EE. Net proceeds from the issuance of Senior Notes EE were

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used to temporarily reduce borrowings outstanding under EPO's $3.5 Billion Multi-Year Revolving Credit Facility (which was used to repay at maturity its $490.5 million principal amount of Senior Notes S due February 2012 and $9.5 million principal amount of TEPPCO Senior Notes due February 2012 prior to the delivery of Senior Notes EE) and for general company purposes. We currently estimate that our capital expenditures for 2011 will approximate $3.8 billion, which includes approximately $3.5 billion for growth capital projects and $315 million for sustaining capital expenditures. Based on current market conditions, we believe we will have sufficient liquidity, cash flow from operations and access to capital markets to fund our capital expenditures and working capital needs.

In January 2012, Standard & Poor's upgraded its corporate credit rating of EPO from BBB- to BBB, while maintaining its outlook for EPO's business as "positive." Moody's Investor Services ("Moody's") did likewise, upgrading its credit rating of EPO from Baa3 to Baa2 and reaffirming that its outlook for EPO's business remained "positive." In February 2012, Fitch Ratings upgraded its corporate credit rating of EPO to BBB while maintaining its outlook for EPO's business as "stable." Based on information currently available to us, we believe we will maintain the aforementioned credit ratings and meet our loan covenant obligations in 2012.

As of the date of this report, we have approximately $2.85 billion of senior notes maturing in the period beginning 2012 through the end of 2014. The U.S. government is expected to run substantial annual budget deficits (exceeding a trillion dollars each year) that will require a corresponding issuance of debt by the U.S. Treasury from 2012 through 2014. The interest rate on U.S. Treasury debt has a direct impact on the cost of our debt. At this time, we are uncertain what the impact of the expected large issuances of U.S. Treasury debt and the prevailing economic and capital market conditions during these future periods will have on the cost and availability of capital. We have executed approximately $1.35 billion of interest rate swaps to hedge a portion of our expected future debt issuances in connection with the refinancing of our debt that matures during the 2012 through 2013 time period. We will continue to monitor and evaluate the condition of the capital markets and interest rate risk with respect to refinancing these maturities and funding our capital expenditures.

Results of Operations

The following table summarizes the key components of our results of operations for the periods presented (dollars in millions):

	For Year Ended December 31,		
	2011	2010	2009
Revenues	$44,313.0	$33,739.3	$25,510.9
Operating costs and expenses	41,318.5	31,449.3	23,565.8
General and administrative costs	181.8	204.8	182.8
Equity in income of unconsolidated affiliates	46.4	62.0	92.3
Operating income	2,859.1	2,147.2	1,854.6
Interest expense	744.1	741.9	687.3
Provision for income taxes	27.2	26.1	25.3
Net income	2,088.3	1,383.7	1,140.3
Net income attributable to noncontrolling interests	41.4	1,062.9	936.2
Net income attributable to partners	2,046.9	320.8	204.1

For information regarding amounts attributable to noncontrolling interests, see Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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Our gross operating margin by business segment and in total is as follows for the periods presented (dollars in millions):

	For Year Ended December 31,		
	2011	2010	2009
NGL Pipelines & Services	$2,184.2	$1,732.6	$1,628.7
Onshore Natural Gas Pipelines & Services	675.3	527.2	501.5
Onshore Crude Oil Pipelines & Services	234.0	113.7	164.4
Offshore Pipeline & Services	228.2	297.8	180.5
Petrochemical & Refined Products Services	535.2	584.5	364.7
Other Investments	14.8	(2.8)	41.1
Total segment gross operating margin	$3,871.7	$3,253.0	$2,880.9

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before provision for income taxes, see "—Other Items—Non-GAAP Reconciliations" included within this Item 7. For additional information regarding our business segments, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The following table summarizes each business segment's contribution to revenues (net of eliminations and adjustments) for the periods presented (dollars in millions):

	For Year Ended December 31,		
	2011	2010	2009
NGL Pipelines & Services:			
Sales of NGLs and related products	$16,724.6	$13,449.4	$11,600.7
Midstream services	758.7	753.1	708.3
Total	17,483.3	14,202.5	12,309.0
Onshore Natural Gas Pipelines & Services:			
Sales of natural gas	2,866.5	2,928.7	2,410.5
Midstream services	863.7	772.9	739.4
Total	3,730.2	3,701.6	3,149.9
Onshore Crude Oil Pipelines & Services:			
Sales of crude oil	15,962.6	10,710.4	7,110.6
Midstream services	98.5	84.4	80.4
Total	16,061.1	10,794.8	7,191.0
Offshore Pipelines & Services:			
Sales of natural gas	1.1	1.3	1.2
Sales of crude oil	9.4	9.5	5.3
Midstream services	245.5	299.9	333.4
Total	256.0	310.7	339.9
Petrochemical & Refined Products Services:			
Sales of petrochemicals and refined products	6,000.6	4,009.1	1,991.8
Midstream services	781.8	720.6	529.3
Total	6,782.4	4,729.7	2,521.1
Total consolidated revenues	$44,313.0	$33,739.3	$25,510.9

Our consolidated revenues are derived from a wide customer base. Our largest non-affiliated customer for 2011, 2010 and 2009 was Shell Oil Company and its affiliates, which accounted for 10.6%, 9.4% and 9.8% of our consolidated revenues, respectively.

Basis of Financial Statement Presentation

In accordance with rules and regulations of the Securities and Exchange Commission ("SEC") and various other accounting standard-setting organizations, our general purpose financial statements reflect the consolidation of financial information of businesses that we control. Our general purpose Consolidated Financial Statements present those investments over which we do not have control as unconsolidated affiliates (e.g., our equity method investment in Energy Transfer Equity). Noncontrolling interest reflects third party and related party ownership of our consolidated subsidiaries.

Prior to the Holdings Merger, Enterprise was a consolidated subsidiary of Holdings, which was Enterprise's parent. Upon completion of the Holdings Merger, Holdings merged with and into a wholly owned subsidiary of Enterprise. The Holdings Merger resulted in Holdings being considered the surviving consolidated entity for accounting purposes, while Enterprise Products Partners L.P. is the surviving consolidated entity for legal and reporting purposes. For accounting purposes, Holdings is deemed the acquirer of the noncontrolling interests in Enterprise that were previously recognized in Holdings' consolidated financial statements (i.e., the acquisition of Enterprise's limited partner interests that were owned by parties other than Holdings).

As a result of the Holdings Merger, Enterprise's consolidated financial and operating results prior to November 22, 2010 have been presented as if Enterprise were Holdings from an accounting perspective (i.e., the financial statements of Holdings became the historical financial statements of Enterprise). While it was a publicly traded partnership, Holdings (NYSE, ticker symbol "EPE") electronically filed its annual and quarterly consolidated financial statements with the SEC. You can access this information at www.sec.gov.

The primary differences between Holdings' and Enterprise's consolidated results of operations were (i) general and administrative costs incurred by Holdings and EPGP (our former general partner); (ii) equity in income of Holdings' noncontrolling ownership interests in Energy Transfer Equity; and (iii) interest expense associated with Holdings' debt. In addition, for periods prior to November 22, 2010, the net assets, income, cash distributions and contributions and other amounts attributable to Enterprise's limited partner interests that were owned by third parties and related parties other than Holdings are presented as a component of noncontrolling interests. See Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our noncontrolling interests.

Historical limited partner units outstanding and earnings per unit amounts presented in our financial statements have been retroactively presented in connection with the 1.5 to one unit-for-unit exchange that occurred under the Holdings Merger. See Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding earnings per unit.

Since we historically consolidated Duncan Energy Partners for financial reporting purposes, the Duncan Merger did not change the basis of presentation of our historical financial statements.

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Selected Price and Volumetric Data

The following table presents selected annual and quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products for the periods presented:

	Natural Gas, $/MMBtu (1)	Ethane, $/gallon (2)	Propane, $/gallon (2)	Normal Butane, $/gallon (2)	Isobutane, $/gallon (2)	Natural Gasoline, $/gallon (2)	Polymer Grade Propylene, $/pound (3)	Refinery Grade Propylene, $/pound (3)	Crude Oil, $/barrel (4)
2009 Averages	$ 3.99	$ 0.48	$ 0.84	$ 1.08	$ 1.19	$ 1.31	$ 0.39	$ 0.34	$ 61.88
2010									
1st Quarter	$ 5.30	$ 0.73	$ 1.24	$ 1.52	$ 1.64	$ 1.82	$ 0.63	$ 0.54	$ 78.72
2nd Quarter	$ 4.09	$ 0.55	$ 1.08	$ 1.47	$ 1.58	$ 1.81	$ 0.65	$ 0.44	$ 78.03
3rd Quarter	$ 4.38	$ 0.48	$ 1.07	$ 1.38	$ 1.43	$ 1.71	$ 0.58	$ 0.44	$ 76.20
4th Quarter	$ 3.80	$ 0.64	$ 1.26	$ 1.62	$ 1.68	$ 2.00	$ 0.59	$ 0.49	$ 85.17
2010 Averages	$ 4.39	$ 0.60	$ 1.16	$ 1.50	$ 1.58	$ 1.84	$ 0.61	$ 0.48	$ 79.53
2011									
1st Quarter	$ 4.11	$ 0.66	$ 1.37	$ 1.75	$ 1.85	$ 2.27	$ 0.76	$ 0.68	$ 94.10
2nd Quarter	$ 4.32	$ 0.78	$ 1.49	$ 1.87	$ 2.02	$ 2.48	$ 0.89	$ 0.79	$ 102.56
3rd Quarter	$ 4.20	$ 0.78	$ 1.54	$ 1.88	$ 2.09	$ 2.37	$ 0.78	$ 0.67	$ 89.76
4th Quarter	$ 3.54	$ 0.86	$ 1.44	$ 1.89	$ 2.26	$ 2.24	$ 0.59	$ 0.44	$ 94.06
2011 Averages	$ 4.04	$ 0.77	$ 1.46	$ 1.85	$ 2.06	$ 2.34	$ 0.76	$ 0.64	$ 95.12

(1) Natural gas prices are based on Henry-Hub I-FERC commercial index prices.
(2) NGL prices for ethane, propane, normal butane, isobutane and natural gasoline are based on Mont Belvieu Non-TET commercial index prices as reported by Oil Price Information Service.
(3) Polymer-grade propylene prices represent average contract pricing for such product as reported by Chemical Market Associates, Inc. ("CMAI"). Refinery grade propylene prices represent weighted-average spot prices for such product as reported by CMAI.
(4) Crude oil prices are based on commercial index prices for West Texas Intermediate as measured on the NYMEX.

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The following table presents our significant average throughput, production and processing volumetric data for the periods presented. These statistics are reported on a net basis, taking into account our ownership interests in certain joint ventures, and reflect the periods in which we owned an interest in such operations. These statistics reflect volumes for newly constructed assets from the dates such assets were placed into service and for recently purchased assets from the date of acquisition.

	For Year Ended December 31,		
	2011	2010	2009
NGL Pipelines & Services, net:			
NGL transportation volumes (MBPD)	2,284	2,322	2,196
NGL fractionation volumes (MBPD)	575	485	461
Equity NGL production (MBPD)	116	121	117
Fee-based natural gas processing (MMcf/d)	3,820	2,932	2,650
Onshore Natural Gas Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	13,231	11,482	10,435
Onshore Crude Oil Pipelines & Services, net:			
Crude oil transportation volumes (MBPD)	678	670	680
Offshore Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	1,065	1,242	1,420
Crude oil transportation volumes (MBPD)	279	320	308
Platform natural gas processing (MMcf/d)	405	513	700
Platform crude oil processing (MBPD)	17	17	12
Petrochemical & Refined Products Services, net:			
Butane isomerization volumes (MBPD)	101	89	97
Propylene fractionation volumes (MBPD)	73	77	68
Octane additive and associated plant production volumes (MBPD)	17	16	10
Transportation volumes, primarily refined products and petrochemicals (MBPD)	759	869	806
Total, net:			
NGL, crude oil, refined products and petrochemical transportation volumes (MBPD)	4,000	4,181	3,990
Natural gas transportation volumes (BBtus/d)	14,296	12,724	11,855
Equivalent transportation volumes (MBPD) (1)	7,762	7,529	7,110

(1) Reflects equivalent energy volumes where 3.8 MMBtus of natural gas are equivalent to one barrel of NGLs.

Comparison of 2011 with 2010

Revenues for 2011 were $44.31 billion compared to $33.74 billion for 2010, a $10.57 billion year-to-year increase. Consolidated revenues from sales of NGLs and related products increased $3.28 billion year-to-year primarily due to higher sales prices in 2011 compared to 2010. Revenues from sales of natural gas decreased $62.4 million year-to-year due to lower sales prices. Crude oil sales revenues increased $5.25 billion year-to-year due to higher sales prices and volumes. Consolidated revenues from sales of petrochemicals and refined products increased $1.99 billion year-to-year primarily due to higher propylene and refined products sales prices in 2011 compared to 2010. Consolidated revenues from other midstream services increased $117.3 million year-to-year primarily due to positive variances of $171.2 million related to the timing of the State Line and Fairplay acquisitions in May 2010 and our acquisition of a trucking business from EPCO in September 2010 (i.e., 2010 includes only a partial year of revenues from these acquired businesses) and $64.9 million related to the start of commercial operations on newly constructed assets such as the Haynesville Extension of our Acadian Gas System in November 2011. Collectively, the remainder of our consolidated revenues from other midstream services decreased $118.8 million year-to-year largely due to a decrease in throughput volumes on our Products Pipeline System and pipeline and platform assets offshore in the Gulf of Mexico.

Operating costs and expenses were $41.32 billion for 2011 compared to $31.45 billion for 2010, a $9.87 billion year-to-year increase. Cost of sales related to our marketing activities increased $8.20 billion year-to-year primarily due to higher crude oil sales volumes and, with the exception of natural gas, higher energy commodity prices. The operating costs and expenses of our natural gas processing plants increased $1.38 billion year-to-year primarily due to (i) an increase in plant thermal reduction ("PTR") costs attributable to higher natural gas processing volumes and (ii) higher NGL prices during 2011 relative to 2010. In general, higher NGL prices result in increased operating costs associated with percent-of-proceeds and margin band types of natural gas processing contracts.

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Consolidated operating costs and expenses also increased $160.6 million year-to-year due to the timing of the State Line and Fairplay acquisitions in May 2010 and our acquisition of a trucking business from EPCO in September 2010 (i.e., 2010 includes only a partial year of operating costs from these acquired businesses). Operating costs and expenses for the remainder of our midstream services increased $195.0 million year-to-year primarily due to higher maintenance and pipeline integrity expenses we incurred in 2011 compared to 2010 and operating costs associated with assets we constructed and placed into service in 2011, including our Haynesville Extension and new Mont Belvieu NGL fractionator.

Depreciation, amortization and accretion expenses included in operating costs and expenses increased $22.4 million year-to-year primarily due to depreciation expense recorded in connection with newly constructed assets being placed into service in mid-year 2010 and in 2011 and depreciation and amortization expense recorded in connection with assets acquired as a result of business combinations in mid-2010. We recorded $27.8 million of non-cash asset impairment charges in 2011 compared to $8.4 million of such charges during 2010. The $19.4 million increase in impairment charges primarily relates to write-downs of spare parts inventory and certain storage cavern assets. Gains from asset sales and related transactions included in operating costs and expenses increased $111.6 million year-to-year primarily due to a $129.1 million gain we recorded as a result of the sale of Crystal to Boardwalk that closed in December 2011.

Changes in our revenues and operating costs and expenses year-to-year are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.46 per gallon during 2011 versus $1.16 per gallon during 2010 – a 26% year-to-year increase. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub in Louisiana) averaged $4.04 per MMBtu during 2011 versus $4.39 per MMBtu during 2010. The market price of crude oil (as measured on the NYMEX) averaged $95.12 per barrel during 2011 compared to $79.53 per barrel during 2010 – a 20% year-to-year increase. See "Selected Price and Volumetric Data" included within this Item 7 for additional historical energy commodity pricing information.

General and administrative costs were $181.8 million for 2011 compared to $204.8 million for 2010, a $23.0 million year-to-year decrease. General and administrative costs for 2011 include transaction expenses of $12.0 million related to the Duncan Merger and $2.9 million related to the sale of Crystal. General and administrative costs for 2010 include $20.2 million of expenses related to the Employee Partnership liquidations and $24.5 million of transaction expenses related to the Holdings Merger. Collectively, the remainder of our general and administrative costs increased $6.8 million year-to-year primarily due to higher employee compensation, office rent and depreciation expenses in 2011 compared to 2010.

Equity income from our unconsolidated affiliates was $46.4 million for 2011 compared to $62.0 million for 2010, a $15.6 million year-to-year decrease. Collectively, equity earnings from Seaway, Centennial Pipeline LLC ("Centennial") and our investees operating in the Gulf of Mexico decreased $38.1 million year-to-year primarily due to lower pipeline throughput volumes in 2011 compared to 2010. Equity earnings from Energy Transfer Equity increased $17.6 million year-to-year. Equity earnings from our investment in Venice Energy Service Company, L.L.C. ("VESCO") increased $6.7 million year-to-year primarily due to higher natural gas processing volumes and margins in 2011 compared to 2010. Collectively, equity earnings from our other equity method investees decreased $1.8 million year-to-year.

Operating income for 2011 was $2.86 billion compared to $2.15 billion for 2010. Collectively, the changes in revenues, costs and expenses and equity income described above resulted in the $711.9 million year-to-year increase in operating income.

Consolidated interest expense increased $2.2 million year-to-year to $744.1 million in 2011 compared to $741.9 million in 2010. In general, interest expense represents that portion of borrowing costs (e.g., interest payments) that are not capitalized in connection with the funding of capital expenditures. Borrowing costs attributable to the funding of construction projects are capitalized until the related asset is placed in service, at which time the associated interest costs are then reflected as interest expense. Any borrowing costs that had been capitalized are expensed as a component of depreciation when the related fixed asset is placed into service. Interest expense also includes the amortization of debt issuance costs and the effects of interest rate hedging activities.

Although our average debt principal balances increased from $13.23 billion in 2010 to $14.59 billion in 2011, a substantial portion of the costs associated with the new borrowings were capitalized in connection with our capital spending program. Capitalized interest increased $59.5 million year-to-year to $106.7 million for 2011 from $47.2 million for 2010. Our consolidated interest expense amounts are directly impacted by changes in the weighted-average fixed and variable interest rates charged under our debt agreements. On average, interest rates continued to decrease over the last year. For example, as we refinanced the maturities of our fixed rate senior notes, the rates we obtained on the new debt issuances were lower than those associated with the debt being refinanced. However, as interest rates declined certain of our interest rate hedges partially mitigated the benefit of lower rates on the higher debt balances.

Consolidated net income increased $704.6 million year-to-year to $2.09 billion for 2011 from $1.38 billion for 2010. Net income attributable to noncontrolling interests was $41.4 million for 2011 compared to $1.06 billion for 2010, which included $1.0 billion attributable to the limited partners of Enterprise other than Holdings. For periods prior to the Holdings Merger, that portion of Enterprise's net income attributable to its limited partner interests owned by third parties and related parties other than Holdings is presented as a component of net income attributable to noncontrolling interests. See Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our net income attributable to noncontrolling interests. Net income attributable to partners increased $1.73 billion year-to-year to $2.05 billion for 2011 from $320.8 million for 2010.

The following information highlights significant year-to-year variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $2.18 billion for 2011 compared to $1.73 billion for 2010, a $451.6 million year-to-year increase. Gross operating margin for 2011 includes $4.3 million of gains related to cash proceeds from business interruption insurance claims. The following paragraphs provide a discussion of segment results excluding gains from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $1.32 billion for 2011 compared to $989.9 million for 2010, a $331.6 million year-to-year increase. Gross operating margin from our NGL marketing activities increased $210.6 million year-to-year due to higher sales margins. Gross operating margin from our natural gas processing plants located in the Rocky Mountains increased $71.7 million year-to-year primarily due to higher natural gas processing margins and higher equity NGL production and fee-based processing volumes during 2011 compared to 2010. Collectively, gross operating margin from our natural gas processing facilities in southern Louisiana and the San Juan and Permian Basins increased $42.4 million year-to-year primarily due to higher natural gas processing margins during 2011 compared to 2010. Results from our facilities in southern Louisiana include a $6.7 million year-to-year increase in equity earnings from our investment in VESCO. Natural gas processing activities on the Fairplay gathering system, which we acquired in May 2010, contributed $8.9 million of the year-to-year increase in gross operating margin.

Gross operating margin from our NGL pipelines and related storage business was $638.4 million for 2011 compared to $604.8 million for 2010, a $33.6 million year-to-year increase. Total NGL transportation volumes decreased to 2,284 MBPD during 2011 from 2,322 MBPD during 2010. Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased $53.0 million year-to-year primarily due to an increase in revenues attributable to changes in the mix of transportation services provided to customers (e.g., increased long-haul delivery volumes and changes in delivery destinations) during 2011 compared to 2010 and an increase in system-wide tariffs in July 2011. Gross operating margin from our NGL storage activities increased $14.9 million year-to-year primarily due to an increase in storage and terminaling fees charged at our NGL terminals in the northeastern U.S. Gross operating margin from our South Texas NGL System increased $5.0 million year-to-year primarily due to a $6.8 million charge we recorded during 2010 related to a dispute involving a pipeline segment on this system.

Collectively, gross operating margin from our NGL pipelines in southern Louisiana decreased $18.5 million year-to-year primarily due to a 25 MBPD decrease in transportation volumes. The year-to-year decrease in NGL transportation volumes on our pipelines in southern Louisiana is primarily due to reduced supplies of NGLs during 2011 compared to 2010 from offshore production in the Gulf of Mexico and reduced volumes of mixed

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NGLs transported from our facility in Mont Belvieu, Texas to NGL fractionators in southern Louisiana. Gross operating margin from our Dixie Pipeline and related NGL terminals decreased $13.7 million year-to-year primarily due to a 20 MBPD decrease in transportation volumes and higher pipeline integrity expenses during 2011. Downtime in connection with pipeline integrity projects we completed on the Dixie Pipeline during 2011 and warmer weather during the winter months of 2011 compared to the same period in 2010 both contributed to the year-to-year decrease in transportation volumes. Gross operating margin from our Houston Ship Channel import/export terminal and a related pipeline decreased $9.2 million year-to-year primarily due to higher operating expenses during 2011 compared to 2010.

Gross operating margin from our NGL fractionation business was $220.0 million for 2011 compared to $137.9 million for 2010, an $82.1 million year-to-year increase. Our NGL fractionation volumes were 575 MBPD during 2011 compared to 485 MBPD during 2010. Gross operating margin from our Mont Belvieu NGL fractionators increased $62.9 million year-to-year primarily due to higher NGL fractionation volumes and fees. During the fourth quarter of 2010, we placed into service a fourth NGL fractionator at our complex in Mont Belvieu, Texas. We completed a fifth NGL fractionator at our Mont Belvieu complex and placed it into service during the fourth quarter of 2011. Collectively, our new NGL fractionators in Mont Belvieu added more than 150 MBPD of NGL fractionation capacity at this key industry hub. Gross operating margin from our Norco NGL fractionator increased $17.3 million year-to-year primarily due to higher NGL prices, which resulted in higher revenues associated with percent-of-liquids contracts and product blending activities during 2011 compared to 2010. Gross operating margin from our Hobbs NGL fractionator increased $8.4 million year-to-year primarily due to higher NGL fractionation volumes and fees. Gross operating margin from our Colorado NGL fractionators, which we sold during March 2011, decreased $4.9 million year-to-year.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $675.3 million for 2011 compared to $527.2 million for 2010, a $148.1 million year-to-year increase. Onshore natural gas transportation volumes were 13.23 TBtus/d during 2011 compared to 11.48 TBtus/d during 2010.

Gross operating margin from our onshore natural gas pipelines and related marketing business was $633.1 million for 2011 compared to $471.7 million for 2010, a $161.4 million year-to-year increase. Gross operating margin from our natural gas marketing activities increased $50.7 million year-to-year primarily due to higher sales volumes and margins. Gross operating margin from our Texas Intrastate System increased $62.9 million year-to-year primarily due to higher firm capacity reservation revenues and a 280 BBtus/d year-to-year increase in natural gas throughput volumes. Increased natural gas production volumes from the Eagle Ford Shale supply basin resulted in stronger demand for our natural gas transportation services during 2011 compared to 2010. The year-to-year increase in transportation volumes on our Texas Intrastate System was also due to greater demand from gas-fired electric generation utilities as a result of record heat in Texas during the summer months of 2011. Gross operating margin from our Acadian Gas System increased $29.3 million year-to-year primarily due to revenues earned by our Haynesville Extension pipeline. The Haynesville Extension of our Acadian Gas System commenced operations in November 2011 and transported 1.22 TBtus/d of natural gas during the fourth quarter of 2011. Our State Line and Fairplay natural gas gathering systems, which we acquired in May 2010, contributed $26.5 million of the year-to-year increase in gross operating margin. Gross operating margin from our Piceance Basin Gathering System increased $6.7 million year-to-year primarily due to a 195 BBtu/d increase in transportation volumes. Gross operating margin from our Jonah Gathering System decreased $14.4 million year-to-year on a 137 BBtu/d decrease in transportation volumes.

Gross operating margin from our natural gas storage business was $42.2 million for 2011 compared to $55.5 million for 2010, a $13.3 million year-to-year decrease. In December 2011, we sold our natural gas storage facilities located near Petal and Hattiesburg, Mississippi. For additional information regarding the sale of these facilities, see "Significant Recent Developments—Sale of Our Mississippi Natural Gas Storage Facilities" within this Item 7.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $234.0 million for 2011 compared to $113.7 million for 2010, a $120.3 million year-to-year increase. Our onshore crude oil transportation volumes increased to 678 MBPD during 2011 from 670 MBPD during 2010. Gross operating margin from our crude oil marketing and related activities increased $96.2 million year-to-year primarily due to higher sales volumes and margins. Our crude oil marketing activities benefited from increased crude oil production volumes from supply basins in the Eagle Ford Shale, Barnett Shale, West Texas and Rocky Mountains. Collectively, gross operating margin from our South Texas System, West Texas System, Red River System and Basin Pipeline System increased $34.1 million year-to-year primarily due to a 46 MBPD increase in throughput volumes and higher average fees during 2011.

Equity earnings from our investment in Seaway decreased $10.8 million year-to-year primarily due to lower volumes delivered to the Cushing hub from the Texas Gulf Coast during 2011 compared to 2010. Net to our interest, throughput volumes on the Seaway pipeline system decreased 37 MBPD year-to-year. As a result of an oversupply of crude oil at the Cushing hub, crude oil in Cushing, Oklahoma is priced at a substantial discount to oil markets on the Gulf Coast. This has led refiners in the Midwest to source a significant amount of their crude oil feedstocks from the Cushing hub rather than shipping such volumes northward from the Gulf Coast (e.g., by using the Seaway pipeline). See “Significant Recent Developments—Plans with Enbridge to Reverse the Seaway Pipeline” within this Item 7, for information regarding a project to reverse the direction of crude oil flows on the Seaway pipeline to enable it to transport oil from the oversupplied Cushing hub to U.S. Gulf Coast refiners.

Offshore Pipelines & Services. Gross operating margin from this business segment was $228.2 million for 2011 compared to $297.8 million for 2010, a $69.6 million year-to-year decrease. Results for 2010 include $27.5 million of gains related to insurance proceeds. Excluding gains from insurance proceeds, gross operating margin from this business segment decreased $42.1 million year-to-year primarily due to the effects of last year’s federal offshore drilling moratorium and the ongoing deliberations of federal authorities to approve drilling and well workover permits. Although crude oil and natural gas drilling activity has resumed on a limited basis since last year’s drilling moratorium (which was in effect from May 2010 to October 2010), certain of our offshore pipeline and platform assets continue to experience reduced throughput volumes as existing wells experience natural production declines. We expect that drilling activity in the Gulf of Mexico will increase in the future as federal agencies allow exploration and production companies to proceed with the drilling of new wells. For additional information regarding the federal offshore drilling moratorium, see “—Additional regulations that cause delays or deter new offshore oil and gas drilling could have a material adverse effect on our financial position, results of operations and cash flows” on page 55 under Item 1A of this annual report.

Gross operating margin from our offshore crude oil pipeline business was $77.4 million for 2011 compared to $97.9 million for 2010, a $20.5 million year-to-year decrease. Our offshore crude oil transportation volumes averaged 279 MBPD during 2011 compared to 320 MBPD during 2010. Collectively, equity earnings from our investments in Poseidon Oil Pipeline Company, L.L.C. (“Poseidon”) and Cameron Highway Oil Pipeline Company (“Cameron Highway”) decreased $16.3 million year-to-year primarily due to lower throughput volumes. Net to our interest, crude oil throughput volumes on the Poseidon and Cameron Highway pipelines decreased 39 MBPD year-to-year. Collectively, gross operating margin from our Shenzi and Constitution Oil Pipelines decreased $4.9 million year-to-year on a 13 MBPD decrease in throughput volumes.

Gross operating margin from our offshore natural gas pipeline business was $40.8 million for 2011 compared to $45.5 million for 2010, a $4.7 million year-to-year decrease. Our offshore natural gas transportation volumes were 1,065 BBtus/d during 2011 versus 1,242 BBtus/d during 2010. Gross operating margin from our Independence Trail pipeline decreased $12.0 million year-to-year primarily due to lower transportation volumes. Natural gas transportation volumes on our Independence Trail pipeline decreased to 461 BBtus/d during 2011 from 576 BBtus/d during 2010 as a result of lower volumes from the Independence Hub platform (see below). Gross operating margin from our High Island Offshore System decreased $4.8 million year-to-year primarily due to a decrease in volumes and 2010 included $4.2 million of revenues attributable to a rate case settlement. Gross operating margin from our Anaconda system increased $6.8 million year-to-year primarily due to a system extension we completed and placed into service during the third quarter of 2011. Collectively, gross operating margin from the remainder of our offshore natural gas pipeline business increased $5.3 million year-to-year primarily due to lower operating expenses on our

Viosca Knoll Gathering System during 2011 compared to 2010.

Gross operating margin from our offshore platform services business was $110.0 million for 2011 compared to $126.9 million for 2010, a $16.9 million year-to-year decrease. On a net basis to our interest, platform natural gas processing volumes were 405 MMcf/d during 2011 compared to 513 MMcf/d during 2010. Gross operating margin from our Independence Hub platform decreased $10.0 million year-to-year primarily due to lower natural gas processing volumes as a result of depletion at existing production wells, the watering-out of certain wells

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and the lingering impact of the federal offshore drilling moratorium which has slowed the drilling of new wells. Gross operating margin from the remainder of our offshore platforms decreased $6.9 million year-to-year primarily due to lower natural gas processing volumes and higher maintenance expenses at our offshore platforms in the Garden Banks area of the Gulf of Mexico.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was $535.2 million for 2011 compared to $584.5 million for 2010, a $49.3 million year-to-year decrease.

Gross operating margin from propylene fractionation and related activities was $161.2 million for 2011 compared to $212.4 million for 2010, a $51.2 million year-to-year decrease. Propylene fractionation volumes were 73 MBPD during 2011 compared to 77 MBPD during 2010. The year-to-year decrease in gross operating margin is primarily due to lower propylene fractionation volumes and sales margins during 2011 compared to 2010. Results for 2010 benefited from the combined effects of high demand for propylene and reduced propylene production from third party petrochemical facilities.

Gross operating margin from butane isomerization was $124.9 million for 2011 compared to $84.9 million for 2010, a $40.0 million year-to-year increase. Butane isomerization volumes increased to 101 MBPD during 2011 from 89 MBPD during 2010. The year-to-year increase in gross operating margin is primarily due to higher isomerization volumes and increased by-product production and associated sales margins.

Gross operating margin from octane enhancement and HPIB production was $109.1 million for 2011 compared to $47.0 million for 2010, a $62.1 million year-to-year increase. Gross operating margin from our octane enhancement facility in Mont Belvieu, Texas increased $54.7 million year-to-year primarily due to higher motor gasoline additive sales volumes and margins during 2011 compared to 2010. The remainder of the year-to-year increase is attributable to the addition of gross operating margin from recently acquired assets.

Gross operating margin from refined products pipelines and related activities was $79.6 million for 2011 compared to $170.8 million for 2010, a $91.2 million year-to-year decrease. Pipeline transportation volumes for the refined products business decreased to 642 MBPD during 2011 from 734 MBPD during 2010. Gross operating margin from our Products Pipeline System decreased $69.8 million year-to-year primarily due to lower throughput volumes and higher operating expenses during 2011 compared to 2010. Equity earnings from our investment in Centennial decreased $9.6 million year-to-year primarily due to lower transportation volumes. Net to our interest, transportation volumes on the Centennial pipeline decreased 22 MBPD year-to-year. Structural shifts in population, reduced demand and increased refinery production in the Midwest have contributed to a decline in demand for the transportation of refined products from the Gulf Coast to the Midwest. Gross operating margin from the marketing of refined products decreased $12.3 million year-to-year primarily due to lower sales margins associated with forward sales contracts.

Of the total year-to-year decrease in gross operating margin from the Products Pipeline System, we estimate that $13.7 million is due to higher operating expenses attributable to the impact of a pipeline leak that occurred in New York State in the third quarter of 2010. Following our repair of the leak, the affected segment of pipe was tested and returned to service in February 2011. In addition, results from our Products Pipeline System for 2011 include $9.1 million of operating expenses related to environmental remediation efforts and pipeline repairs following pipeline leaks that occurred in Texas and Louisiana. The remaining $47.0 million year-to-year decrease in gross operating margin from our Products Pipeline System is primarily due to lower volumes delivered to Northeast U.S. markets and higher operating costs such as expenses for maintenance and pipeline integrity projects.

Gross operating margin from marine transportation and other segment services was $60.4 million for 2011 compared to $69.4 million for 2010, a $9.0 million year-to-year decrease. Gross operating margin from marine transportation decreased $14.4 million year-to-year primarily due to lower revenues resulting from our sale of marine transportation vessels in February 2011 that comprised our former bunker fuel transportation fleet. Gross operating margin from other services increased $5.4 million year-to-year primarily due to our acquisition of truck transport operations from EPCO in September 2010.

Other Investments. Our equity earnings from Energy Transfer Equity were $14.8 million for 2011 compared to a loss of $2.8 million for 2010, a $17.6 million year-to-year increase. Our equity income from this

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investment was reduced by $31.5 million and $36.3 million of excess cost amortization during 2011 and 2010, respectively. The equity income we recorded from this investment for 2011 is based on our estimate of Energy Transfer Equity's net income attributable to partners. According to financial statements filed with the SEC, Energy Transfer Equity's net income attributable to partners for 2010 was $192.8 million, which included $66.4 million of charges in connection with the termination of interest rate swaps and a $52.6 million non-cash impairment charge to write-down the carrying value of its investment in Midcontinent Express Pipeline, LLC.

Comparison of 2010 with 2009

Revenues for 2010 were $33.74 billion compared to $25.51 billion for 2009, an $8.23 billion year-to-year increase. Higher energy commodity sales prices and volumes during 2010 compared to 2009 resulted in a $7.99 billion year-to-year increase in consolidated revenues from the sale of NGLs, natural gas, crude oil and petrochemical and refined products. Consolidated revenues from sales of NGLs and related products increased $1.85 billion year-to-year primarily due to higher sales prices in 2010 compared to 2009. Revenues from sales of natural gas increased $518.3 million year-to-year due to higher sales prices and volumes. Crude oil sales revenues increased $3.6 billion year-to-year primarily due to higher sales prices. Consolidated revenues from sales of other petrochemical and refined products increased $2.02 billion year-to-year primarily due to (i) higher petrochemical and refined products sales volumes and (ii) higher propylene sales prices during 2010 compared to 2009. Collectively, the remainder of our consolidated revenues increased $240.1 million year-to-year primarily due to revenues generated from businesses we acquired or assets we constructed, principally the State Line and Fairplay natural gas gathering systems we acquired in May 2010 and a trucking business we acquired from EPCO in September 2010.

Operating costs and expenses were $31.45 billion for 2010 compared to $23.57 billion for 2009, a $7.88 billion year-to-year increase. The cost of sales related to our marketing activities increased $7.23 billion year-to-year primarily due to higher energy commodity prices and sales volumes. The operating costs and expenses of our natural gas processing plants increased $493.6 million year-to-year primarily due to higher PTR costs attributable to an increase in natural gas prices and processing volumes. Operating costs and expenses for 2010 include approximately $174.3 million attributable to business acquisitions and the placing in service of newly constructed assets during the year. Operating costs and expenses for 2009 include aggregate charges of $135.3 million related to our dissociation from the Texas Offshore Port System partnership ("TOPS") and $28.7 million of expenses incurred by TEPPCO in connection with its river terminal business.

Depreciation, amortization and accretion expenses included in operating costs and expenses increased $127.0 million year-to-year primarily due to an increase in depreciation and amortization expense attributable to assets acquired in connection with business acquisitions in 2010 and the placing in service of newly constructed assets during 2010. We recorded $8.4 million of non-cash asset impairment charges during 2010 compared to $33.5 million of charges during 2009, a $25.1 million year-to-year decrease. Non-cash impairment charges recorded in 2009 include $22.8 million of expense incurred by TEPPCO related to its refined products terminals. Gains from asset sales and related transactions included in operating costs and expenses increased $44.4 million year-to-year primarily due to $56.6 million gains recorded in connection with our disposition of certain offshore assets in 2010.

Changes in our revenues and operating costs and expenses year-to-year are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.16 per gallon during 2010 versus $0.85 per gallon during 2009 – a 36% year-to-year increase. The Henry Hub market price of natural gas averaged $4.39 per MMBtu during 2010 versus $3.99 per MMBtu during 2009. The NYMEX crude oil market price averaged $79.53 per barrel during 2010 compared to $61.88 per barrel during 2009 – a 29% year-to-year increase.

General and administrative costs were $204.8 million for 2010 compared to $182.8 million for 2009, a $22.0 million year-to-year increase. General and administrative costs for 2010 include $20.2 million of expense related to the

Employee Partnership liquidations and $24.5 million of transaction expenses related to the Holdings Merger. General and administrative costs for 2009 include $31.0 million of transaction expenses related to the TEPPCO Merger. Collectively, the remainder of our general and administrative costs increased $8.3 million year-to-year primarily due to higher expenses for director compensation and legal and tax professional services.

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Equity income from our unconsolidated affiliates was $62.0 million for 2010 compared to $92.3 million for 2009. The $30.3 million year-to-year decrease is primarily due to a $43.9 million decrease in equity earnings from Energy Transfer Equity, partially offset by improved results from our investments in midstream energy companies operating in Gulf of Mexico and higher earnings from K/D/S Promix, L.L.C. ("Promix") and Centennial.

Operating income for 2010 was $2.15 billion compared to $1.85 billion for 2009. Collectively, the changes in revenues, costs and expenses and equity income described above resulted in the $292.6 million year-to-year increase in operating income.

Interest expense increased to $741.9 million for 2010 from $687.3 million for 2009, a $54.6 million year-to-year increase. Interest expense for 2010 includes $31.0 million of charges related to Holdings' interest rate swaps and the write-off of Holdings' unamortized debt issuance costs. The remainder of the increase in interest expense is primarily due to EPO's issuance of Senior Notes Q and R during October 2009 and Senior Notes X, Y and Z in May 2010. Our average debt principal balance increased to $13.23 billion during 2010 from $13.0 billion during 2009.

As a result of items noted in the previous paragraphs, our consolidated net income increased $243.4 million year-to-year to $1.38 billion for 2010 compared to $1.14 billion for 2009. Net income attributable to noncontrolling interests was $1.06 billion for 2010 compared to $936.2 million for 2009. See Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our net income attributable to noncontrolling interests. Net income attributable to partners increased $116.7 million year-to-year to $320.8 million for 2010 compared to $204.1 million for 2009.

The following information highlights significant year-to-year variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $1.73 billion for 2010 compared to $1.63 billion for 2009, a $103.9 million year-to-year increase. Gross operating margin for 2009 includes $5.9 million of gains related to insurance proceeds. The following paragraphs provide a discussion of segment results excluding gains from insurance proceeds.

Gross operating margin from our natural gas processing and related NGL marketing business was $989.9 million for 2010 compared to $947.9 million for 2009, a $42.0 million year-to-year increase. Equity NGL production increased to 121 MBPD during 2010 from 117 MBPD during 2009. Our Rocky Mountains natural gas processing plants contributed $31.6 million of the year-to-year increase in gross operating margin primarily due to increased equity NGL production. Gross operating margin from our natural gas processing activities in Texas increased $16.4 million year-to-year due to higher volumes and processing margins, which includes $9.8 million of gross operating margin attributable to natural gas processing activities on the Fairplay system that we acquired in May 2010. Gross operating margin from our NGL marketing activities increased $4.5 million year-to-year due to higher sales volumes and margins. Collectively, gross operating margin from the remainder of our natural gas processing activities decreased $10.5 million year-to-year primarily due to lower natural gas processing margins and fee-based processing volumes in at our plants in southern Louisiana and the San Juan and Permian Basins.

Gross operating margin from our NGL pipelines and related storage business was $604.8 million for 2010 compared to $538.9 million for 2009, a $65.9 million year-to-year increase. Total NGL transportation volumes increased to 2,322 MBPD during 2010 from 2,196 MBPD during 2009. Collectively, gross operating margin from our Louisiana NGL pipelines and Dixie Pipeline increased $55.7 million year-to-year primarily due to a 50 MBPD increase in throughput volumes and an increase in certain fees. Gross operating margin from our Houston Ship Channel import/export terminal and a related pipeline increased $17.6 million year-to-year primarily due to a 46 MBPD year-to-year increase in volumes. Gross operating margin from our storage and related terminal businesses increased

$29.1 million year-to-year primarily due to higher storage volumes and fees, with our Mont Belvieu storage facility contributing $12.7 million of this increase. In addition, gross operating margin from our Rio Grande pipeline, which we acquired in the fourth quarter of 2009, increased $5.3 million year-to-year. Improved results from these assets were partially offset by a combined $39.2 million decrease in gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related terminals attributable to a $29.2 million benefit recorded for the Mid-America Pipeline System in 2009 related to a rate case settlement, a combined 16 MBPD decrease in throughput volumes on these systems and higher operating expenses. Gross operating margin from our remaining NGL pipelines decreased $2.6 million year-to-year primarily due to a $6.8 million charge we recorded during the third quarter of 2010 for a dispute involving a pipeline in South Texas.

Gross operating margin from our NGL fractionation business was $137.9 million for 2010 compared to $136.0 million for 2009, a $1.9 million increase year-to-year. Our NGL fractionation volumes were 485 MBPD during 2010 compared to 461 MBPD during 2009. Gross operating margin from our Mont Belvieu and Promix NGL fractionation facilities increased $15.1 million year-to-year primarily due to higher NGL fractionation volumes and fees. During the fourth quarter of 2010, we added 75 MBPD of NGL fractionation capacity by completing and placing into service a fourth NGL fractionator at our complex in Mont Belvieu, Texas. Gross operating margin from the remainder of our NGL fractionators decreased $13.2 million year-to-year, primarily due to a $12.6 million year-to-year decrease in gross operating margin from our Norco fractionator related to hedging and operating gains recorded during 2009 that did not repeat in 2010.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $527.2 million for 2010 compared to $501.5 million for 2009, a $25.7 million year-to-year increase. Our onshore natural gas transportation volumes were 11.48 TBtus/d during 2010 compared to 10.44 TBtus/d during 2009.

Gross operating margin from our onshore natural gas pipelines and related marketing business was $471.7 million for 2010 compared to $448.5 million for 2009, a $23.2 million year-to-year increase. Gross operating margin for 2010 includes $33.0 million from the State Line and Fairplay natural gas gathering systems, which we acquired in May 2010. Gross operating margin from our Texas Intrastate System increased $22.0 million year-to-year primarily due to higher firm capacity reservation fees on the Sherman Extension pipeline. Gross operating margin from our San Juan Gathering System increased $21.1 million year-to-year primarily due to higher average gathering fees and lower operating expenses during 2010 compared to 2009. Our Central Treating Facility in the Rocky Mountains, which commenced operations in March 2009, contributed $11.5 million of the year-to-year increase in segment gross operating margin. Collectively, gross operating margin from our Jonah and Carlsbad gathering systems decreased $16.0 million year-to-year primarily due to lower natural gas gathering volumes. Collectively, gross operating margin from the remainder of our onshore natural gas pipelines and related marketing activities decreased $48.4 million year-to-year primarily due to lower sales margins and higher transportation and storage expenses associated with our natural gas marketing activities.

Natural gas basis differentials in Texas (specifically, the difference in natural gas prices between markets in West Texas and East Texas) were significantly lower during 2010 relative to 2009. The year-to-year decrease in basis differentials resulted in lower sales margins associated with our natural gas marketing activities during 2010 and a decrease in interruptible transportation volumes on our Texas Intrastate System.

Gross operating margin from our natural gas storage business was $55.5 million for 2010 compared to $53.0 million for 2009. The $2.5 million year-to-year increase in gross operating margin is primarily due to higher revenues and lower operating expenses at our Petal natural gas storage facility during 2010 compared to 2009.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $113.7 million for 2010 compared to $164.4 million for 2009, a $50.7 million year-to-year decrease. Total onshore crude oil transportation volumes decreased to 670 MBPD during 2010 compared to 680 MBPD during 2009. Gross operating margin from our crude oil marketing and related activities decreased $53.9 million year-to-year primarily due to lower sales margins resulting from a competitive crude oil marketing environment (i.e., lower basis differentials year-to-year) and higher pipeline and truck transportation costs. Basis differentials represent the difference in crude oil prices between two locations or price differences for various qualities of crude oil (e.g., “sweet” crude versus “sour” crude). Gross operating margin from our crude oil terminal operations in Midland, Texas and Cushing, Oklahoma decreased $3.6 million year-to-year primarily due to higher operating expenses. Collectively, gross operations from the remainder of our onshore crude oil businesses increased $6.8 million year-to-year primarily due to higher throughput volumes on our West Texas pipeline system and higher volumes and fees on our Red River pipeline system.

Offshore Pipelines & Services. Gross operating margin from this business segment was $297.8 million for 2010 compared to $180.5 million for 2009, a $117.3 million year-to-year increase. Results for 2010 include $27.5 million of gains related to insurance proceeds compared to $39.7 million of such gains in 2009. Results for 2009

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include $135.3 million of charges related to our dissociation from TOPS. Gross operating margin from this business segment decreased $5.8 million year-to-year excluding the effects of insurance proceeds and charges related to TOPS.

In August 2008, we, including TEPPCO, together with Oiltanking Holding Americas, Inc. ("Oiltanking") formed TOPS. In April 2009, we and TEPPCO dissociated from TOPS and recorded a $68.4 million charge to write-off our investment in the joint venture. In September 2009, we entered into a settlement agreement with certain affiliates of Oiltanking that resolved all disputes between the parties related to the business and affairs of the TOPS project. We recognized approximately $66.9 million of expense during the third quarter of 2009 in connection with the payment of this cash settlement.

The following paragraphs provide a discussion of segment results excluding insurance-related gains and the charges associated with TOPS.

In general, natural gas and crude oil drilling activity in the Gulf of Mexico ceased as a result of the federal offshore drilling moratorium, which went into effect in May 2010. This resulted in lower throughput volumes available to certain of our offshore pipeline and platform assets. The moratorium was lifted in October 2010.

Gross operating margin from our offshore crude oil pipeline business was $97.9 million for 2010 compared to $79.3 million for 2009, an $18.6 million year-to-year increase. Equity earnings from Poseidon increased $5.7 million year-to-year primarily due to higher transportation volumes and lower operating expenses. In addition, gross operating margin from our Shenzi crude oil pipeline, which commenced operations in April 2009, increased $4.0 million year-to-year. Collectively, gross operating margin from the remainder of our crude oil pipelines increased $8.9 million year-to-year primarily due to increased transportation volumes. Certain of these pipelines were either in limited service or out-of-service completely during 2009 due to the lingering effects of Hurricanes Gustav and Ike on energy infrastructure in the Gulf of Mexico. Despite the effects of the federal offshore drilling moratorium, our offshore crude oil transportation volumes averaged 320 MBPD during 2010 compared to 308 MBPD during 2009.

Gross operating margin from our offshore natural gas pipeline business was $45.5 million for 2010 compared to $54.2 million for 2009, an $8.7 million year-to-year decrease. Our offshore natural gas transportation volumes were 1,242 BBtus/d during 2010 versus 1,420 BBtus/d during 2009. Gross operating margin from our Independence Trail pipeline decreased $31.2 million year-to-year primarily due to lower transportation volumes. Natural gas transportation volumes on our Independence Trail pipeline decreased to 576 BBtus/d during 2010 from 805 BBtus/d during 2009 as a result of well depletion and lost production (i.e., wells that were shut-in or watered-out) and indirect impacts of the federal offshore drilling moratorium. Collectively, gross operating margin from the remainder of our offshore natural gas pipelines increased $22.5 million year-to-year primarily due to a year-to-year decrease in operating expenses as a result of property damage repair expenses we recorded during 2009 and revenue increases on our High Island Offshore System in 2010.

Gross operating margin from our offshore platform services business was $126.9 million for 2010 compared to $142.6 million for 2009, a $15.7 million year-to-year decrease. Our net platform natural gas processing volumes were 513 MMcf/d during 2010 compared to 700 MMcf/d during 2009. The year-to-year decrease in gross operating margin is primarily due to lower natural gas processing volumes at our Independence Hub platform as a result of well depletion and lost production (i.e., wells that were shut-in or watered-out) and indirect impacts of the federal offshore drilling moratorium.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was $584.5 million for 2010 compared to $364.7 million for 2009, a $219.8 million year-to-year increase.

Gross operating margin from propylene fractionation and related activities was $212.4 million for 2010 compared to $89.6 million for 2009, a $122.8 million year-to-year increase. Propylene fractionation volumes increased to 77 MBPD during 2010 from 68 MBPD during 2009. The year-to-year increase in gross operating margin is primarily due to higher propylene fractionation volumes and sales margins during 2010. Propylene sales margins increased year-to-year as a result of improved consumer demand for propylene derivative products and lower propylene production from third party petrochemical facilities (which impacted supply) during 2010 compared to 2009.

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Gross operating margin from octane enhancement and HPIB production was $47.0 million for 2010 compared to $11.5 million for 2009, a $35.5 million year-to-year increase. Octane enhancement production volumes were 16 MBPD during 2010 compared to 10 MBPD during 2009. The year-to-year increase in gross operating margin is primarily due to higher sales volumes and margins from motor gasoline additives and revenues from by-product sales.

Gross operating margin from butane isomerization was $84.9 million for 2010 compared to $76.2 million for 2009, an $8.7 million year-to-year increase. Butane isomerization volumes decreased to 89 MBPD during 2010 from 97 MBPD during 2009. The year-to-year increase in gross operating margin is primarily due to higher commodity prices, which resulted in increased revenues from by-product sales and more than offset the effect of lower isomerization volumes.

Gross operating margin from refined products pipelines and related activities was $170.8 million for 2010 compared to $124.7 million for 2009, a $46.1 million year-to-year increase. Pipeline transportation volumes for the refined products business were 734 MBPD during 2010 compared to 682 MBPD during 2009. Gross operating margin for 2009 includes a $28.7 million charge recognized by TEPPCO in the third quarter of 2009 in connection with its river terminal business. Collectively, gross operating margin from the remainder of our refined products pipelines and related activities increased $17.4 million year-to-year primarily due to the expansion of our refined products marketing activities and the completion of our 5.3 million barrel refined products terminal in Port Arthur, Texas, which generated $7.4 million of gross operating margin for 2010.

Gross operating margin from marine transportation and other segment services was $69.4 million for 2010 compared to $62.7 million for 2009, a $6.7 million year-to-year increase. An increase in gross operating margin attributable to earnings from acquired and constructed marine vessels was partially offset by higher operating expenses during 2010 as compared to 2009.

Other Investments. Our equity earnings from Energy Transfer Equity were a loss of $2.8 million for 2010 compared to income of $41.1 million for 2009, a $43.9 million year-to-year decrease. Our equity income from this investment was reduced by $36.3 million and $36.6 million of excess cost amortization during 2010 and 2009, respectively. According to financial statements filed with the SEC, Energy Transfer Equity's net income attributable to partners was $192.8 million and $442.5 million for 2010 and 2009, respectively. Energy Transfer Equity's net income attributable to partners for 2010 included $66.4 million of charges in connection with the termination of interest rate swaps and a $52.6 million non-cash impairment charge to write-down the carrying value of its investment in Midcontinent Express Pipeline, LLC. In addition, Energy Transfer Equity's net income for 2010 included losses of $52.4 million associated with the change in fair value of non-hedged interest rate derivatives compared to gains of $33.6 million for 2009.

Liquidity and Capital Resources

At December 31, 2011, we had $3.37 billion of consolidated liquidity, which is defined as unrestricted cash on hand plus borrowing capacity available under our $3.5 Billion Multi-Year Revolving Credit Facility. Our primary cash requirements are for routine operating expenses, debt service, working capital, capital expenditures, business combinations and distributions to partners. We expect to fund our short-term cash requirements for operating expenses and sustaining capital expenditures using operating cash flows and borrowings under our revolving credit facility. Our expenditures for long-term productive assets (e.g., business expansion projects and acquisitions) are expected to be funded through a variety of sources (either separately or in combination) including the use of operating cash flows, borrowings under our revolving credit facility, proceeds from divestitures and the issuance of additional equity and debt securities. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements. Based on current market conditions, we believe we will have sufficient liquidity, cash flow from operations and access to capital markets to fund our capital expenditures and working capital needs.

Long-Term Debt

In September 2011, EPO entered into a new $3.5 Billion Multi-Year Revolving Credit Facility that matures in September 2016. Initial borrowings under this variable-rate credit facility were used to refinance and terminate

EPO’s prior $1.75 Billion Multi-Year Revolving Credit Facility. Future borrowings under the new $3.5 billion revolving credit facility may be used for working capital, capital expenditures, acquisitions and general company purposes. EPO’s borrowings under the revolving credit facility are unsecured general obligations that are guaranteed by Enterprise and are non-recourse to Enterprise GP.

As defined by the credit agreement, variable interest rates charged under this facility bear interest at a London Interbank Offer Rate (“LIBOR”) plus an applicable margin. In addition, EPO is required to pay a quarterly facility fee on each lender’s commitment irrespective of commitment usage. This revolving credit facility allows us to request up to two one-year extensions of the maturity date, subject to lender approval. The total amount of the bank commitments may be increased, without the consent of the lenders, by an amount not exceeding $500 million by adding one or more lenders to the facility and/or requesting that the commitments of existing lenders be increased.

We had approximately $14.48 billion of principal amounts outstanding under consolidated debt agreements at December 31, 2011. In January 2011, EPO issued $750.0 million in principal amount of 5-year unsecured notes (“Senior Notes AA”) and $750.0 million in principal amount of 30-year unsecured notes (“Senior Notes BB”). Senior Notes AA were issued at 99.901% of their principal amount, have a fixed interest rate of 3.20%, and mature in February 2016. Senior Notes BB were issued at 99.317% of their principal amount, have a fixed interest rate of 5.95%, and mature in February 2041. Net proceeds from the issuance of Senior Notes AA and BB were used to repay $450.0 million in aggregate principal amount of Senior Notes B that matured in February 2011, to temporarily reduce borrowings outstanding under EPO’s $1.75 Billion Multi-Year Revolving Credit Facility and for general company purposes.

In August 2011, EPO issued $650.0 million in principal amount of 10-year unsecured notes (“Senior Notes CC”) and $600.0 million in principal amount of 30-year unsecured notes (“Senior Notes DD”). Senior Notes CC were issued at 99.790% of their principal amount, have a fixed interest rate of 4.05%, and mature in February 2022. Senior Notes DD were issued at 99.887% of their principal amount, have a fixed interest rate of 5.70%, and mature in February 2042. Net proceeds from the issuance of Senior Notes CC and DD were used to temporarily reduce borrowings outstanding under EPO’s $1.75 Billion Multi-Year Revolving Credit Facility and for general company purposes.

In February 2012, EPO issued $750.0 million in principal amount of 30-year unsecured Senior Notes EE. These notes were issued at 99.542% of their principal amount, have a fixed-rate of interest of 4.85% and mature on August 15, 2042. Net proceeds from the issuance of Senior Notes EE were used to temporarily reduce borrowings outstanding under EPO’s $3.5 Billion Multi-Year Revolving Credit Facility (which was used to repay at maturity its $490.5 million principal amount of Senior Notes S due February 2012 and $9.5 million principal amount of TEPPCO Senior Notes due February 2012 prior to the delivery of Senior Notes EE) and for general company purposes.

Our $3.5 Billion Multi-Year Revolving Credit Facility and each of our indentures for our public debt contain conventional financial covenants and other restrictions. For example, EPO’s ability to make distributions to Enterprise Products Partners L.P., and our ability to make distributions to our partners, would be restricted if an event of default exists or if such distributions would cause an event of default or otherwise violate a covenant under the revolving credit facility. Our revolving credit facility also restricts our ability to incur additional debt above certain levels. Our public debt indentures currently do not limit the amount of future indebtedness that we can create, incur, assume or guarantee.

We were in compliance with the financial covenants of our consolidated debt agreements at December 31, 2011. For additional information regarding our consolidated debt obligations, see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Registration Statements

We may issue additional equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. In July 2010, Enterprise, including EPO, filed a universal shelf registration statement (the "2010 Shelf") with the SEC. The 2010 Shelf allows Enterprise and EPO (on a standalone basis) to issue an

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unlimited amount of equity and debt securities, respectively. EPO utilized the 2010 Shelf to issue its Senior Notes AA and BB in January 2011, Senior Notes CC and DD in August 2011 and Senior Notes EE in February 2012.

In December 2011, Enterprise utilized the 2010 Shelf to issue 10,350,000 of its common units, including the exercise of an over-allotment option for 1,350,000 common units, at $44.68 per unit in an underwritten public offering. Total net cash proceeds from the December 2011 equity offering, including the exercise of the over-allotment option, were approximately $448.5 million after deducting underwriting discounts, commissions and offering expenses.

Enterprise also has a registration statement on file with the SEC in connection with its distribution reinvestment plan ("DRIP"). Enterprise issued 2,241,589 common units in total under its DRIP plan during 2011, which generated net cash proceeds of $90.4 million. After taking into account the number of common units issued under this registration statement through December 31, 2011, Enterprise may issue an additional 26,173,283 common units under its DRIP.

In May 2011, Enterprise's original employee unit purchase plan ("EUPP") reached the maximum 1,200,000 common units permitted under the plan and was terminated. In September 2011, in connection with the Duncan Merger, the Duncan Energy Partners EUPP was assumed by Enterprise and converted into a new Enterprise EUPP. Enterprise filed a registration statement with the SEC authorizing the issuance of 440,879 common units under the assumed plan. Enterprise issued 96,315 common units in total under its EUPP plans during 2011, which generated net cash proceeds of $4.0 million.

The net cash proceeds received in 2011 from Enterprise's DRIP and EUPP were used to temporarily reduce borrowings outstanding under EPO's revolving credit facilities and for general company purposes.

Credit Ratings

As of February 29, 2012, the investment-grade credit ratings of EPO's senior unsecured debt securities were: BBB from Standard and Poor's; Baa2 from Moody's; and BBB from Fitch Ratings. In January 2012, Standard & Poor's upgraded its corporate credit rating of EPO from BBB- to BBB, while maintaining its outlook for EPO's business as "positive." Moody's did likewise, upgrading its credit rating of EPO from Baa3 to Baa2 and reaffirming that its outlook for EPO's business remained "positive." In February 2012, Fitch Ratings upgraded its corporate credit rating of EPO to BBB while maintaining its outlook for EPO's business as "stable." EPO's credit ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any of our securities. A credit rating can be revised upward or downward or withdrawn at any time by a rating agency, if it determines that circumstances warrant such a change. A credit rating from one rating agency should be evaluated independently of credit ratings from other rating agencies.

A potential downgrade of EPO's credit ratings could result in us posting financial collateral in connection with our guaranty of Centennial's debt, which was $51.0 million at December 31, 2011. Furthermore, we may enter into contracts in connection with our commodity and interest rate hedging activities that may require the posting of financial collateral if EPO's credit ratings were downgraded below investment grade.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our consolidated cash flows from operating, investing and financing activities for the periods indicated (dollars in millions). For additional information regarding our cash flow amounts, please refer to the Statements of Consolidated Cash Flows included under Item 8 of this annual report.

	For Year Ended December 31,		
	2011	2010	2009

Net cash flows provided by operating activities	$3,330.5	$2,300.0	$2,410.3
Cash used in investing activities	2,777.6	3,251.6	1,547.7
Cash provided by (used in) financing activities	(598.6)	961.1	(863.9)

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Net cash flows provided by operating activities are largely dependent on earnings from our consolidated business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide products and services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. The products that we process, sell, transport or store are principally used as fuel for residential, agricultural and commercial heating; as feedstocks in petrochemical manufacturing; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of a decline in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or producers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows. For a more complete discussion of these and other risk factors pertinent to our business, see Item 1A of this annual report.

The following information highlights significant year-to-year fluctuations in our consolidated cash flow amounts:

Comparison of 2011 with 2010

Operating Activities. The $1.03 billion increase in net cash flows provided by operating activities was primarily due to increased profitability (e.g., our gross operating margin increased $618.7 million year-to-year) and the timing of related cash receipts and disbursements.

Investing Activities. The $474.0 million decrease in cash used for investing activities was primarily due to the following:

§ Cash used for business combinations decreased $1.31 billion year-to-year, primarily due to the acquisition of the State Line and Fairplay natural gas gathering systems for approximately $1.2 billion in May 2010.

§ Proceeds from asset sales and related transactions increased $927.9 million year-to-year primarily due to the sale of 9,672,576 Energy Transfer Equity common units for $375.2 million and the sale of certain natural gas storage facilities for $547.8 million during 2011.

§ Restricted cash related to our hedging activities decreased $60.2 million (a cash inflow) during 2011 due to changes in the margin requirements of our commodity hedging positions. For 2010, restricted cash related to our hedging activities increased $35.0 million (a cash outflow).

§ Capital spending for property, plant and equipment, net of contributions in aid of construction costs, increased $1.84 billion year-to-year primarily due to our Eagle Ford Shale and Haynesville Shale growth capital projects. For additional information regarding our capital spending program, see "Liquidity and Capital Resources – Capital Spending" included within this Item 7.

Financing Activities. As discussed under "Basis of Financial Statement Presentation" within this Item 7, the financial statements of Enterprise prior to the Holdings Merger were those of Holdings. As a result, cash distributions paid to partners during 2010 represent payments to the former unitholders of Holdings whereas cash distributions paid to partners during 2011 represent payments to the unitholders of Enterprise. Also, cash distributions paid to noncontrolling interests during 2010 include cash payments to the unitholders of Enterprise (other than Holdings). Cash contributions from noncontrolling interests during 2010 primarily represent proceeds from Enterprise's equity offerings (other than purchases by Holdings).

Cash used in financing activities was $598.6 million during 2011 compared to cash provided by financing activities of $961.1 million during 2010. The $1.56 billion decrease in cash flows from financing activities was primarily due to the following:

§ On a combined basis, cash contributions from noncontrolling interests and net cash proceeds from the issuance of common units decreased $1.08 billion year-to-year. Substantially all of the cash contributions from noncontrolling interests during 2010 relate to net cash proceeds generated from the issuance of common units by Enterprise prior to the completion of the Holdings Merger. In total, Enterprise issued

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12,687,904 common units and 46,328,053 common units during 2011 and 2010, respectively, in connection with underwritten offerings and its DRIP and EUPP.

§ Cash distributions to partners and noncontrolling interests were a combined $2.04 billion during 2011 compared to $1.79 billion during 2010. The increase in cash distributions is primarily due to increases in the number of Enterprise's distribution-bearing common units outstanding (including common units issued in connection with the Holdings Merger and Duncan Merger) and in its quarterly distribution rates.

§ Net borrowings under our consolidated debt agreements decreased $191.7 million year-to-year. EPO issued $2.75 billion of new senior notes and repaid $450.0 million in senior notes during 2011 compared to the issuance of $2.0 billion in senior notes and repayment of $500.0 million in senior notes and $54.0 million of other long-term debt during 2010. In addition, net repayments under consolidated revolving credit facilities and term loans increased approximately $988.3 million year-to-year. For additional information regarding our consolidated debt obligations, see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Comparison of 2010 with 2009

Operating Activities. The $110.3 million decrease in net cash flows provided by operating activities was primarily due to the following:

§ Net cash flows from consolidated operations (excluding cash payments for interest, distributions received from unconsolidated affiliates and cash payments for income taxes) decreased $69.5 million year-to-year. The decrease in cash flows from operating activities is generally due to the timing of cash receipts and disbursements in our operating accounts, partially offset by increased profitability (e.g., our gross operating margin increased $372.1 million year-to-year).

§ Cash payments for interest increased approximately $77.3 million year-to-year primarily due to an increase in fixed-rate debt obligations with higher interest rates. Our average consolidated debt principal outstanding was $13.23 billion during 2010 compared to $13.0 billion during 2009.

§ Distributions received from unconsolidated affiliates increased $22.6 million year-to-year primarily due to higher distributions received from Poseidon and Promix. In February 2010, we also began receiving distributions from Skelly-Belvieu Pipeline Company, L.L.C.

§ Cash payments for income taxes decreased $13.9 million year-to-year primarily due to higher payments made in 2009 attributable to the Texas Margin Tax and a taxable gain arising from the sale of certain Dixie assets.

Investing Activities. The $1.7 billion increase in cash used for investing activities was primarily due to the following:

§ Cash used for business combinations increased $1.21 billion year-to-year, primarily due to the May 2010 acquisition of the State Line and Fairplay natural gas gathering systems for approximately $1.2 billion. For additional information regarding this transaction, see Note 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

§ Capital spending for property, plant and equipment, net of contributions in aid of construction costs, increased $435.6 million year-to-year primarily due to our Eagle Ford Shale and Haynesville Shale growth capital projects.

§ Restricted cash related to our hedging activities increased $35.0 million (a cash outflow) during 2010 due to changes in the margin requirements of our commodity hedging positions. For 2009, restricted cash related to our hedging activities decreased $140.2 million (a cash inflow).

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§ Proceeds from asset sales and related transactions increased $102.3 million year-to-year primarily due to insurance proceeds received during 2010 related to the disposal of certain offshore pipeline and platform assets and the sale of our membership interest in the general partner of Energy Transfer Equity.

Financing Activities. Cash provided by financing activities was $961.1 million during 2010 compared to cash used in financing activities of $863.9 million during 2009. The $1.83 billion year-to-year change in financing activities was primarily due to the following:

§ Net borrowings under our consolidated debt agreements increased $1.41 billion year-to-year. EPO issued $2.0 billion in senior notes during 2010 compared to $1.6 billion in senior notes and during 2009. In addition, net repayments under consolidated revolving credit facilities decreased approximately $1.07 billion year-to-year.

§ Cash contributions from noncontrolling interests increased $89.5 million year-to-year primarily due to an increase in the offering prices of Enterprise's common units in connection with its underwritten equity offerings in 2010 compared to those in 2009. In addition, Duncan Energy Partners issued common units in 2009, which generated $137.4 million in proceeds. Net cash proceeds from the issuance of Enterprise common units in December 2010, following the Holdings Merger, were $528.5 million.

§ Cash distributions paid to partners (i.e., the unitholders of Holdings prior to the Holdings Merger) increased $41.0 million year-to-year due to increases in Holdings' quarterly distribution rates and in the number of its distribution-bearing units outstanding.

§ Cash distributions paid to noncontrolling interests increased $156.3 million year-to-year primarily due to increases in the number of Enterprise's distribution-bearing common units outstanding and in its quarterly distribution rates, partially offset by the cessation of cash distributions to the former owners of TEPPCO in connection with the TEPPCO Merger.

Capital Spending

An integral part of our business strategy involves expansion through growth capital projects, business combinations and investments in joint ventures. We believe that we are positioned to continue to expand our system of assets through the construction of new facilities and to capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities in the Rocky Mountains, Midcontinent, Northeast and U.S. Gulf Coast regions, including the Barnett, Eagle Ford, Haynesville, Marcellus and Utica Shale plays and deepwater Gulf of Mexico producing regions. See "Significant Recent Developments" within this Item 7 for information regarding our current and proposed major capital projects, including the development of our ATEX Express long-haul ethane pipeline, SEKCO crude oil pipeline and multiple projects in the Eagle Ford Shale.

Although our current focus is on expansion through growth capital projects, management continues to analyze potential business combinations, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In past years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We believe this trend will continue and expect independent oil and natural gas companies to consider similar divestitures.

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The following table summarizes our capital spending for the periods indicated (dollars in millions):

	For Year Ended December 31,		
	2011	2010	2009
Capital spending for property, plant and equipment, net: (1)			
Growth capital projects (2)	$3,552.3	$1,766.2	$1,373.9
Sustaining capital projects (3)	290.3	235.9	192.6
Capital spending for business combinations	--	1,313.9	107.3
Investments in unconsolidated affiliates	30.0	8.0	19.6
Other investing activities	22.4	--	1.4
Total capital spending	$3,895.0	$3,324.0	$1,694.8

(1) On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. Contributions in aid of construction costs were $24.9 million, $38.7 million and $17.8 million for the years ended December 31, 2011, 2010 and 2009, respectively. Growth and sustaining capital amounts presented in the table are presented net of related contributions in aid of construction costs.
(2) Growth capital projects either result in additional revenue streams from existing assets or expand our asset base through construction of new facilities that will generate additional revenue streams.
(3) Sustaining capital expenditures are capital expenditures (as defined by GAAP) resulting from improvements to and major renewals of existing assets. Such expenditures serve to maintain existing operations but do not generate additional revenues.

For the year ended December 31, 2011, we spent $3.55 billion on growth capital projects, of which approximately $867 million was for the Haynesville Extension and $1.59 billion for Eagle Ford Shale projects.

Based on information currently available, we estimate our consolidated capital spending for 2012 will approximate $3.8 billion, which includes estimated expenditures of $3.5 billion for growth capital projects and $315 million for sustaining capital expenditures. Our forecast of consolidated capital expenditures for 2012 is based on our announced strategic operating and growth plans, which are dependent upon our ability to generate the required funds from either operating cash flows or other means, including borrowings under debt agreements, issuance of additional debt and equity securities, and potential divestitures. We may revise our forecast of capital spending due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast of capital spending may change as a result of decisions made by management at a later date, which may include the addition of costs associated with unforeseen acquisition opportunities.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be a principal factor in determining how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future growth needs and, although we currently intend to make the forecast capital expenditures noted above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

At December 31, 2011, we had approximately $1.31 billion in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction projects in Texas, including those in the Eagle Ford Shale and at our Mont Belvieu facility.

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Pipeline Integrity Costs

Our pipelines are subject to safety programs administered by the U.S. Department of Transportation ("DOT"). This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (e.g., NGL, crude oil, refined products and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs. The following table summarizes our pipeline integrity costs, including those attributable to DOT regulations, for the periods presented (dollars in millions):

	For Year Ended December 31,		
	2011	2010	2009
Expensed	$64.7	$39.4	$44.9
Capitalized	52.6	40.4	37.7
Total	$117.3	$79.8	$82.6

We expect the cost of our pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $101.0 million in 2012.

Designated Units Issued in Connection with Holdings Merger

In connection with the Holdings Merger, a privately held affiliate of EPCO agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from us with respect to a certain number of our common units (the "Designated Units") it owned over a five-year period after the merger closing date of November 22, 2010. The number of Designated Units to which the temporary distribution waiver applies is as follows for distributions paid or to be paid, if any, during the following calendar years: 30,610,000 during 2011; 26,130,000 during 2012; 23,700,000 during 2013; 22,560,000 during 2014; and 17,690,000 during 2015. Distributions paid to partners during calendar year 2011 excluded the initial 30,610,000 Designated Units; however, distributions to be paid, as applicable, to partners in calendar year 2012 (beginning with the February 2012 distribution) will exclude 26,130,000 Designated Units. As a result, the number of our distribution-bearing units increased by 4,480,000 units beginning with the February 2012 distribution and will increase in subsequent years as the number of Designated Units declines.

Critical Accounting Policies and Estimates

In our financial reporting processes, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of our financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses for each reporting period. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect. The following describes the estimation risk currently underlying our most significant financial statement items:

Depreciation Methods and Estimated Useful Lives of Property, Plant and Equipment

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of an asset. Our estimate of depreciation expense incorporates management assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts prospectively. Examples of such circumstances include (i) changes in laws and regulations that limit the estimated economic life of an asset, (ii) changes in technology that render an asset obsolete, (iii) changes in expected salvage values, or (iv) significant changes in the forecast life of proved reserves of applicable resource basins, if any.

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At December 31, 2011 and 2010, the net carrying value of our property, plant and equipment was $22.19 billion and $19.33 billion, respectively. We recorded $776.6 million, $745.7 million and $678.1 million in depreciation expense for the years ended December 31, 2011, 2010 and 2009, respectively.

Measuring Recoverability of Long-Lived Assets and Equity Method Investments

Long-lived assets, which include property, plant and equipment and intangible assets with finite useful lives, are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes might be production declines that are not replaced by new discoveries or long-term decreases in the demand or price of natural gas, NGLs, crude oil or refined products. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the asset. Estimates of undiscounted cash flows are based on a number of assumptions including anticipated operating margins and volumes; estimated useful life of the asset or asset group; and estimated salvage values. If the carrying value of a long-lived asset is not recoverable, an impairment charge would be recorded for the excess of a long-lived asset's carrying value over its estimated fair value, which is derived from an analysis of the asset's estimated future cash flows, the market value of similar assets and replacement cost of the asset less any applicable depreciation or amortization. In addition, fair value estimates also include usage of probabilities for a range of possible outcomes.

An equity method investment is evaluated for impairment whenever events or changes in circumstances indicate that there is a possible permanent loss in value of the investment (i.e., other than a temporary decline). Examples of such events include sustained operating losses of the investee or long-term negative changes in the investee's industry. The carrying value of an equity method investment is not recoverable if it exceeds the sum of discounted estimated cash flows expected to be derived from the investment. Estimates of discounted cash flows are based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment's underlying assets.

A significant change in the assumptions we use to measure recoverability of long-lived assets and equity method investments could result in our recording a non-cash impairment charge. Any such write-down of the value of such assets would increase operating costs and expenses at that time. During 2011, 2010 and 2009, we recognized non-cash asset impairment charges related to property, plant and equipment of $16.7 million, $8.0 million and $29.3 million, respectively, which are a component of operating costs and expenses. For additional information regarding these impairment charges, see Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. We did not record any non-cash impairment charges related to our equity method investments in 2011, 2010 or 2009.

Amortization Methods and Estimated Useful Lives of Qualifying Intangible Assets

The specific, identifiable intangible assets of a business depend largely upon the nature of its operations. Potential identifiable intangible assets include items such as intellectual property, customer contracts and relationships, and non-compete agreements. The method used to value each intangible asset will vary depending upon a number of factors, including the nature of the asset and the economic returns it is generating or is expected to generate.

Customer relationship intangible assets represent the estimated economic value we assigned to information about customers and the ability to have regular contact with them as a result of business combinations and assets purchases. These relationships may arise from formal contractual arrangements or through routine contact by sales or service representatives. The value we assign to customer relationships is amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the associated oil and natural gas resource basins from which the customers produce are estimated to be depleted. Our estimate of the useful life of each resource basin is predicated on a number of factors, including reserve estimates and the economic viability of production and exploration activities.

Our contract-based intangible assets represent rights we own arising from discrete contractual agreements, such as the long-term rights we possess under the Shell natural gas processing agreement and the Jonah natural gas transportation contracts. A contract-based intangible asset with a finite life is amortized over its estimated useful

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life (or term), which is the period over which the asset is expected to contribute directly or indirectly to our cash flows. Our estimates of useful life are based on a number of factors, including (i) the expected useful life of the related tangible assets (e.g., a fractionation facility, pipeline or other asset), (ii) any legal or regulatory developments that would impact such contractual rights, and (iii) any contractual provisions that enable us to renew or extend such agreements.

If our assumptions regarding the estimated useful life of an intangible asset were to change, then the amortization period for such asset would be adjusted accordingly. Changes in the estimated useful life of an intangible asset would impact operating costs and expenses prospectively from the date of change. If we determine that an intangible asset's unamortized cost is not recoverable due to impairment, we would be required to reduce the asset's carrying value to its estimated fair value. Any such write-down of the value of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2011 and 2010, the carrying value of our intangible asset portfolio was \$1.66 billion and \$1.84 billion, respectively. We recorded \$147.0 million, \$137.6 million and \$119.9 million in amortization expense associated with our intangible assets for the years ended December 31, 2011, 2010 and 2009, respectively.

For additional information regarding our intangible assets, see Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Methods We Employ to Measure the Fair Value of Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing at the end of each fiscal year, and more frequently, if circumstances indicate it is probable that the fair value of goodwill is below its carrying amount. Goodwill impairment testing involves determining the fair value of the associated reporting unit. These fair value amounts are based on assumptions regarding the future economic prospects of the businesses that make up the reporting unit. Such assumptions include (i) discrete financial forecasts for the businesses contained within the reporting unit, which rely on management's estimates of operating margins, throughput volumes and similar factors; (ii) long-term growth rates for cash flows beyond the discrete forecast period; and (iii) appropriate discount rates.

If the fair value of a reporting unit (including its inherent goodwill) is less than its carrying value, a charge to operating costs and expenses is required to reduce the carrying value of the goodwill to its implied fair value. Based on our most recent goodwill impairment test, the estimated fair value of each of our reporting units was substantially in excess of its carrying value (i.e., by at least 10%).

At December 31, 2011 and 2010, the carrying value of our goodwill was \$2.09 billion and \$2.11 billion, respectively. We did not record any goodwill impairment charges in 2011 or 2010; however, we did recognize a \$1.3 million goodwill impairment charge in 2009. For additional information regarding our goodwill, see Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Revenue Recognition Policies and Use of Estimates for Revenues and Expenses

In general, we recognize revenue from customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists; (ii) delivery has occurred or services have been rendered; (iii) the buyer's price is fixed or determinable; and (iv) collectibility is reasonably assured. We record revenue when sales contracts are settled (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed). For additional information regarding our revenue recognition policies, see Note 4 of the Notes to

Consolidated Financial Statements included under Item 8 of this annual report. We record any necessary allowance for doubtful accounts as required by our established policy.

Our use of estimates for certain revenues and expenses has increased as a result of SEC regulations that require us to submit financial information on accelerated time frames. Such estimates are necessary due to the time required to compile actual billing information and receive third party data needed to record transactions for financial reporting purposes. One example of our use of estimates is the accrual of an estimate of processing plant revenue and the cost of natural gas for a given month (prior to receiving actual customer and vendor-related plant operating information for a specific period). These estimates reverse in the following month and are offset by the corresponding actual customer billing and vendor-invoiced amounts. Accordingly, we include one month of certain estimated data in our results of operations. Such estimates are generally based on actual volume and price data through the first part of the month and estimated for the remainder of the month.

Changes in facts and circumstances may result in revised estimates and could affect our reported financial statements and accompanying disclosures. If the assumptions underlying our revenue and expense estimates prove to be substantially incorrect, it could result in material adjustments in results of operations between periods. We review our estimates based on currently available information.

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Other Items

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2011 (dollars in millions):

		Payment or Settlement due by Period			
Contractual Obligations	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Scheduled maturities of debt obligations (1)	$14,482.7	$500.0	$2,350.0	$1,550.0	$10,082.7
Estimated cash payments for interest (2)	$16,109.5	$819.6	$1,447.4	$1,265.5	$12,577.0
Operating lease obligations (3)	$386.4	$58.3	$87.1	$70.5	$170.5
Purchase obligations: (4)					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas	$4,974.8	$909.4	$1,547.4	$1,311.2	$1,206.8
NGLs	$6,048.0	$2,806.4	$2,411.2	$830.4	$--
Crude oil	$1,770.3	$1,770.3	$--	$--	$--
Petrochemicals and refined products	$2,027.8	$1,309.5	$495.6	$222.7	$--
Other	$49.7	$7.6	$14.4	$12.9	$14.8
Underlying major volume commitments:					
Natural gas (in BBtus)	1,738,568	321,030	547,435	456,851	413,252
NGLs (in MBbls)	88,207	42,503	35,580	10,124	--
Crude oil (in MBbls)	18,015	18,015	--	--	--
Petrochemicals and refined products (in MBbls)	28,074	17,962	6,896	3,216	--
Service payment commitments (5)	$627.3	$100.3	$171.7	$147.3	$208.0
Capital expenditure commitments (6)	$1,312.5	$1,312.5	$--	$--	$--
Other long-term liabilities (7)	$352.8	$--	$72.1	$28.6	$252.1
Total	$48,141.8	$9,593.9	$8,596.9	$5,439.1	$24,511.9

(1) Represents contractually scheduled future maturities of our consolidated debt principal obligations after taking into consideration the long-term refinancing of Senior Notes S and the TEPPCO Senior Notes due February 2012 using proceeds from the issuance of Senior Notes EE on February 15, 2012. For information regarding our consolidated debt obligations, see Notes 12 and 23 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

(2) Estimated cash payments for interest are based on the principal amount of our consolidated debt obligations outstanding at December 31, 2011, the scheduled maturities of such balances (after taking into account the issuance of Senior Notes EE and related refinancing activities as noted above), and the applicable fixed or variable interest rates paid during 2011. With respect to our variable-rate debt obligations, we applied the weighted-average interest rate paid during 2011 to determine the estimated cash payments. See Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for the weighted-average variable interest rates charged in 2011 under our credit agreements. In addition, our estimate of cash payments for interest gives effect to interest rate swap agreements that were in place at December 31, 2011. See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding these derivative instruments. Our estimated cash payments for interest are significantly influenced by the long-term maturities of our junior subordinated notes (due August 2066 through January 2068). Our estimated cash payments for interest with respect to each junior subordinated note are based on the current fixed interest rate for each note applied to the entire remaining term through the respective maturity date.

(3) Primarily represents leases of underground salt dome caverns for the storage of natural gas and NGLs, office space with affiliates of EPCO and land held pursuant to right-of-way agreements.
(4) Represents enforceable and legally binding agreements to purchase goods or services as of December 31, 2011. The estimated payment obligations are based on contractual prices in effect at December 31, 2011 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery.
(5) Primarily represents our unconditional payment obligations under firm pipeline transportation contracts.
(6) Represents unconditional payment obligations for services to be rendered or products to be delivered in connection with our capital spending program, including our share of the capital spending commitments of our unconsolidated affiliates.
(7) As reflected on our consolidated balance sheet at December 31, 2011, other long-term liabilities primarily represent the noncurrent portion of asset retirement obligations, deferred revenues and accrued obligations for pipeline transportation deficiency fees and interest rate derivative instruments.

For additional information regarding our significant contractual obligations, see Note 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that have or are reasonably expected to have a material current or future effect on our financial position, revenues, expenses, results of operations, liquidity, capital expenditures or capital resources.

Related Party Transactions

In September 2011, we completed the Duncan Merger, which was a related party transaction. See "—Significant Recent Developments—Completion of the Duncan Merger" within this Item 7 for information regarding completion of the Duncan Merger. For additional information regarding our related party transactions, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report as well as Item 13 of this annual report.

Non-GAAP Reconciliations

The following table presents a reconciliation of total segment gross operating margin to operating income and further to income before provision for income taxes for the periods indicated (dollars in millions):

	For Year Ended December 31,		
	2011	2010	2009
Total segment gross operating margin	$3,871.7	$3,253.0	$2,880.9
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(958.7)	(936.3)	(809.3)
Non-cash asset impairment charges	(27.8)	(8.4)	(33.5)
Operating lease expenses paid by EPCO	(0.3)	(0.7)	(0.7)
Gains from asset sales and related transactions in operating costs and expenses	156.0	44.4	--
General and administrative costs	(181.8)	(204.8)	(182.8)
Operating income	2,859.1	2,147.2	1,854.6
Other expense, net	(743.6)	(737.4)	(689.0)
Income before provision for income taxes	$2,115.5	$1,409.8	$1,165.6

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered an alternative to GAAP operating income.

We define total segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expenses; (ii) non-cash asset impairment charges; (iii) operating lease expenses for which we did not have the payment obligation; (iv) gains and losses from asset sales and related transactions; and (v) general and administrative costs. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in the preparation of our Consolidated Financial Statements. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before any allocation of earnings to noncontrolling interests.

Regulation

For information regarding the impact of federal, state or local regulatory measures on our business, see "—Regulation" under Item 1 and 2 of this annual report.

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Insurance Matters

For information regarding insurance matters, see Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Recent Accounting Developments

Accounting standard setting organizations have been very active in recent years. Recently, they issued new and revised accounting guidance on a number of topics, including fair value measurements, presentation of comprehensive income, testing goodwill for impairment and balance sheet offsetting. We do not believe that adoption of this new guidance will have a material impact on our future Consolidated Financial Statements. For information regarding these recent accounting developments, see Note 3 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Income Tax Matter

Provision for income taxes primarily relates to our state tax obligations under the Revised Texas Franchise Tax and the federal and state tax obligations of our consolidated subsidiaries taxed as corporations. In January 2012, we submitted applications to the Internal Revenue Service for the conversion of certain of our entities taxed as corporations into pass-through entities. If these conversions are approved, we expect to recognize an income tax benefit during the first quarter of 2012 of approximately $46.5 million, which is attributable to the difference between the deferred taxes accrued by these entities as of the date of conversion and any current income tax due in connection with the conversion.

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

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with certain anticipated future transactions, we use derivative instruments. Derivatives are financial instruments whose fair values are determined by changes in specified benchmarks such as interest rates or commodity prices. Fair value is defined as the price that would be received to sell an asset or be paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. Derivative instruments typically include futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

We assess the risk of each of our derivative instrument portfolios using a sensitivity analysis model. The sensitivity analysis applied to each portfolio measures the potential income or loss (i.e., the change in fair value of the derivative instrument portfolio) based upon a hypothetical 10% movement in the underlying interest rates or quoted market prices (as applicable) at the dates indicated. In addition to these variables, the fair value of each portfolio is influenced by fluctuations in the notional amounts of the instruments and the discount rates used to determine the present values.

The calculated results of the sensitivity analysis model do not reflect the impact that the same hypothetical price movement would have on the hedged exposures to which they relate. Therefore, the impact on the fair value of a derivative instrument resulting from a change in interest rates or quoted market prices (as applicable) would normally be offset by a corresponding gain or loss on the hedged debt instrument, inventory value or forecasted transaction assuming: (i) the derivative instrument functions effectively as a hedge of the underlying risk; (ii) the derivative instrument is not closed out in advance of its expected term; and (iii) the hedged forecasted transaction occurs within the expected time period. When considering that the majority of our derivative portfolios are designated as hedges, the sensitivities presented in the quantitative disclosures would most often be expected to have corresponding offsets.

We routinely review the effectiveness of our derivative instrument portfolios in light of current market conditions. If changes in market conditions or exposures warrant, the nature and volume of derivative instruments may change depending on the specific exposures being managed.

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See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our derivative instruments and hedging activities.

Interest Rate Derivative Instruments

We may utilize interest rate swaps, forward starting swaps and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy is a component in controlling our overall cost of capital associated with such borrowings. Interest rate swaps exchange the stated interest rate paid on a notional amount of existing debt for the fixed or floating interest rate stipulated in the derivative instrument. Forward starting swaps perform a similar function except that they are associated with interest rates underlying anticipated future issuances of debt. The composition of our derivative instrument portfolios may change from period-to-period depending on our hedging requirements.

The following table summarizes our portfolio of interest rate swaps at December 31, 2011 (dollars in millions):

Hedged Transaction	Number and Type of Derivative(s) Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes C	1 fixed-to-floating swap	$100.0	1/04 to 2/13	6.4% to 2.3%	Fair value hedge
Senior Notes G	3 fixed-to-floating swaps	$300.0	10/04 to 10/14	5.6% to 1.5%	Fair value hedge
Senior Notes P	7 fixed-to-floating swaps	$400.0	6/09 to 8/12	4.6% to 2.7%	Fair value hedge
Senior Notes AA	10 fixed-to-floating swaps	$750.0	1/11 to 2/16	3.2% to 1.3%	Fair value hedge
Undesignated swaps	6 floating-to-fixed swaps	$600.0	5/10 to 7/14	0.4% to 2.0%	Mark-to-market

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value ("FV") of our interest rate swap portfolio at the dates presented (dollars in millions):

		Interest Rate Swap Portfolio Aggregate Fair Value at (1)		
Scenario	Resulting Classification	December 31, 2010	December 31, 2011	January 31, 2012
FV assuming no change in underlying interest rates	Asset	$35.3	$67.2	$76.8
FV assuming 10% increase in underlying interest rates	Asset	36.1	64.4	74.8
FV assuming 10% decrease in underlying interest rates	Asset	34.6	70.0	78.8

(1) The portfolio's aggregate fair value at a given date is based on a variety of factors, including the number and types of derivatives outstanding at that date, the notional value of the swaps and associated interest rates.

In February 2012, we settled eleven fixed-to-floating interest rate swaps having an aggregate notional amount of $800.0 million, resulting in gains totaling $41.7 million. These gains will be amortized to earnings (as a decrease in interest expense) using the effective interest method over the forecasted hedged period.

The following table summarizes our portfolio of forward starting swaps at December 31, 2011 (dollars in millions):

Hedged Transaction	Number and Type of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Future debt offering	10 forward starting swaps (1)	$500.0	2/12	4.5%	Cash flow hedge
Future debt offering	7 forward starting swaps	$350.0	8/12	3.7%	Cash flow hedge
Future debt offering	16 forward starting swaps	$1,000.0	3/13	3.7%	Cash flow hedge

(1) These swaps were settled in February 2012 in connection with the issuance of Senior Notes EE (see below).

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The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value ("FV") of our forward starting swap portfolio at the dates presented (dollars in millions):

		Forward Starting Swap Portfolio Aggregate Fair Value at (1)		
Scenario	Resulting Classification	December 31, 2010	December 31, 2011	January 31, 2012
FV assuming no change in underlying interest rates	Asset (Liability)	$19.2	$(290.7)	$(316.6)
FV assuming 10% increase in underlying interest rates	Asset (Liability)	80.0	(251.8)	(279.7)
FV assuming 10% decrease in underlying interest rates	Liability	(44.3)	(330.6)	(354.4)

(1) The portfolio's aggregate fair value at a given date is based on a variety of factors, including the number and types of derivatives outstanding at that date, the notional value of the swaps and associated interest rates.

Due to a decrease in forward London Interbank Offered Rates ("LIBOR") in 2011, the fair value of our forward starting swap portfolio was a liability of $290.7 million at December 31, 2011 and $316.6 million at January 31, 2012. In connection with the issuance of Senior Notes EE in February 2012, we settled ten forward starting swaps having an aggregate notional value of $500.0 million, resulting in losses totaling $115.3 million. These losses will be reflected in other comprehensive income for the first quarter of 2012 and amortized to earnings (as an increase in interest expense) using the effective interest method over the forecasted hedge period of ten years. Any gain or loss ultimately recognized upon settlement of the remaining forward starting swaps would be amortized into earnings as a reduction or increase, respectively, in interest expense over the forecasted hedge period.

Commodity Derivative Instruments

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward agreements, futures contracts, fixed-for-float swaps, basis swaps and options contracts.

Our predominant hedging strategies are: (i) hedging natural gas processing margins; (ii) hedging anticipated future contracted sales of NGLs, refined products and crude oil associated with volumes held in inventory and (iii) hedging the fair value of natural gas in inventory. The following information summarizes these hedging strategies:

§ The objective of our natural gas processing strategy is to hedge an amount of gross margin associated with our natural gas processing activities. We achieve this objective by using physical and financial instruments to lock in the purchase prices of natural gas consumed as PTR and the sales prices of the related NGL products. This program consists of (i) the forward sale of a portion of our expected equity NGL production at fixed prices through June 2012, which is achieved through the use of forward physical sales contracts and commodity derivative instruments and (ii) the purchase of commodity derivative instruments having a notional amount based on the volume of natural gas expected to be consumed as PTR in the production of such equity NGL production.

At December 31, 2011, this program had hedged future remaining estimated gross margins (before plant operating expenses) of $108.6 million on 4.2 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through June 2012. At January 31, 2012, this program had hedged future estimated gross margins (before plant operating expenses) of $311.6 million on 7.7 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through December 2012. Our estimates of future gross margins are subject to various business risks, including unforeseen production outages or declines, counterparty risk, or similar events or developments that are outside of our control.

§ The objective of our NGL, refined products and crude oil sales hedging program is to hedge the margins of anticipated future sales of inventory by locking in sales prices through the use of forward physical sales contracts and commodity derivative instruments.

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§ The objective of our natural gas inventory hedging program is to hedge the fair value of natural gas currently held in inventory by locking in the sales price of the inventory through the use of commodity derivative instruments.

Certain basis swaps, basis spread options and other derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of natural gas necessary to optimize our owned and contractually committed transportation and storage capacity.

There is some uncertainty involved in the timing of these transactions often due to the development of more favorable profit opportunities or when spreads are insufficient to cover variable costs thus reducing the likelihood that the transactions will occur as originally forecasted. As a result of this timing uncertainty, these derivative instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of these assets.

The earnings volatility caused by fluctuations in non-cash, mark-to-market earnings cannot be predicted and the impact to earnings could be material.

The following table summarizes our commodity derivative instruments outstanding at December 31, 2011:

	Volume (1)		Accounting
Derivative Purpose	Current (2)	Long-Term (2)	Treatment
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction ("PTR") (3)	12.6 Bcf	n/a	Cash flow hedge
Forecasted sales of NGLs (4)	2.0 MMBbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs	0.3 MMBbls	n/a	Cash flow hedge
Forecasted sales of octane enhancement products	0.9 MMBbls	0.1 MMBbls	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	9.3 Bcf	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	4.2 MMBbls	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	3.6 MMBbls	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products	0.8 MMBbls	n/a	Cash flow hedge
Forecasted sales of refined products	1.6 MMBbls	n/a	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil	0.4 MMBbls	n/a	Cash flow hedge
Forecasted sales of crude oil	1.0 MMBbls	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (5,6)	354.2 Bcf	58.3 Bcf	Mark-to-market
Refined products risk management activities (6)	0.6 MMBbls	n/a	Mark-to-market
Crude oil risk management activities (6)	5.4 MMBbls	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.

(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is December 2013, May 2012 and December 2013, respectively.
(3) PTR represents the British thermal unit equivalent of the NGLs extracted from natural gas by a processing plant, and includes the natural gas used as plant fuel to extract those liquids, plant flare and other shortages.
(4) Forecasted sales of NGL volumes under natural gas processing exclude 2.2 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.
(5) Current volumes include approximately 87.8 Bcf of physical derivative instruments that are predominantly priced at an index plus a premium or minus a discount related to location differences.
(6) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

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The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our natural gas marketing portfolio at the dates presented (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2010	December 31, 2011	January 31, 2012
FV assuming no change in underlying commodity prices	Asset (Liability)	$(12.4)	$22.2	$20.6
FV assuming 10% increase in underlying commodity prices	Asset (Liability)	(21.5)	14.9	14.0
FV assuming 10% decrease in underlying commodity prices	Asset (Liability)	(3.3)	29.5	27.2

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our NGL, refined products and petrochemical operations portfolio at the dates presented (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2010	December 31, 2011	January 31, 2012
FV assuming no change in underlying commodity prices	Liability	$(40.3)	$(12.3)	$(20.5)
FV assuming 10% increase in underlying commodity prices	Liability	(104.5)	(32.2)	(61.0)
FV assuming 10% decrease in underlying commodity prices	Asset	24.0	7.6	20.1

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our crude oil marketing portfolio at the dates presented (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2010	December 31, 2011	January 31, 2012
FV assuming no change in underlying commodity prices	Asset (Liability)	$1.8	$(7.6)	$(1.5)
FV assuming 10% increase in underlying commodity prices	Liability	(0.3)	(10.0)	(4.0)
FV assuming 10% decrease in underlying commodity prices	Asset (Liability)	4.0	(5.0)	1.1

Product Purchase Commitments

We have long and short-term purchase commitments for natural gas, NGLs, petrochemicals and other hydrocarbons with several suppliers. The purchase prices that we are obligated to pay under these contracts are based on market prices at the time we take delivery of the volumes. For additional information regarding these commitments, see "—Other Items—Contractual Obligations" included under Item 7 of this annual report.

Item 8. Financial Statements and Supplementary Data

Our Consolidated Financial Statements, together with the independent registered public accounting firm's report of Deloitte & Touche LLP ("Deloitte & Touche") begins on page F-1 of this annual report.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

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Item 9A. Controls and Procedures.

Disclosure Controls and Procedures

As of the end of the period covered by this annual report, our management carried out an evaluation, with the participation of our general partner's chief executive officer (Michael A. Creel, who is our principal executive officer) and chief financial officer (W. Randall Fowler, our principal financial officer), of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based on this evaluation, as of the end of the period covered by this annual report, Mr. Creel and Mr. Fowler concluded:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our principal executive and financial officers, as appropriate to allow for timely decisions regarding required disclosures; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fourth quarter of 2011, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

The required certifications of Mr. Creel and Mr. Fowler under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 are included as exhibits to this annual report (see Exhibits 31 and 32 under Item 15 of this annual report).

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MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2011

The management of Enterprise Products Partners L.P. and its consolidated subsidiaries, including its chief executive officer and chief financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal control system was designed to provide reasonable assurance to the management of Enterprise Products Partners L.P. and the Board of Directors of its general partner regarding the preparation and fair presentation of Enterprise Products Partners L.P.'s published financial statements.

Our management assessed the effectiveness of Enterprise Products Partners L.P.'s internal control over financial reporting as of December 31, 2011. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in Internal Control—Integrated Framework. This assessment included a review of the design and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on our assessment, we believe that, as of December 31, 2011, Enterprise Products Partners L.P.'s internal control over financial reporting is effective based on those criteria.

Our Audit and Conflicts Committee is composed of independent directors who are not officers or employees of our general partner. This committee meets regularly with members of management, Internal Audit and representatives of Deloitte & Touche LLP, our independent registered public accounting firm, to discuss the adequacy of Enterprise Products Partners L.P.'s internal controls over financial reporting, financial statements and the nature, extent and results of the audit effort. Management reviews all of Enterprise Products Partners L.P.'s significant accounting policies and assumptions affecting the results of operations with the Audit and Conflicts Committee. Both the independent registered public accounting firm and internal auditors have direct access to the Audit and Conflicts Committee without the presence of management.

Deloitte & Touche LLP has issued its attestation report (the "Report of Independent Registered Public Accounting Firm") regarding our internal control over financial reporting. That report is included within this Item 9A.

Pursuant to the requirements of Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended, this annual report on Internal Control Over Financial Reporting has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on February 29, 2012.

/s/ Michael A. Creel		/s/ W. Randall Fowler	
Name:	Michael A. Creel	Name:	W. Randall Fowler
Title:	Chief Executive Officer of our general partner, Enterprise Products Holdings LLC	Title:	Chief Financial Officer of our general partner, Enterprise Products Holdings LLC

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products Holdings LLC and the
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

We have audited the internal control over financial reporting of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2011, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting as of December 31, 2011. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's Board of Directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and the related statements of consolidated operations, comprehensive income, cash flows, and equity as of and for the year ended December 31, 2011 of the Company and our report dated February 29, 2012 expresses an unqualified opinion on those financial statements and includes an explanatory paragraph concerning the effects of the merger between Enterprise GP Holdings L.P. and the Company on November 22, 2010.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 29, 2012

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Partnership Management

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for our management, administrative or operating functions. Pursuant to the ASA, these roles are performed by employees of EPCO, which are under the direction of the Board of Directors (the "Board") and executive officers of Enterprise GP. For a description of the ASA, see "Relationship with EPCO and Affiliates—EPCO ASA" under Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The executive officers of Enterprise GP are elected for one-year terms and may be removed, with or without cause, only by the Board. Our unitholders do not elect the officers or directors of Enterprise GP. The DD LLC Trustees, through their control of Enterprise GP, have the ability to elect, remove and replace at any time, all of the officers and directors of our general partner. Each member of the Board of Enterprise GP serves until such member's death, resignation or removal. The employees of EPCO who served as directors of our general partner during 2011 were Messrs. Bachmann, Creel, Cunningham, Fowler and Teague and Ms. Williams.

Notwithstanding any contractual limitation on its obligations or duties, Enterprise GP is liable for all debts we incur (to the extent not paid by us), except to the extent that such indebtedness or other obligations are non-recourse to Enterprise GP. Whenever possible, Enterprise GP intends to make any such indebtedness or other obligations non-recourse to itself.

Under our limited partnership agreement and subject to specified limitations, we will indemnify to the fullest extent permitted by Delaware law, from and against all losses, claims, damages or similar events, any director or officer, or while serving as director or officer, any person who is or was serving as a tax matters member or as a director, officer, tax matters member, employee, partner, manager, fiduciary or trustee of our partnership or any of our affiliates. Additionally, we will indemnify to the fullest extent permitted by law, from and against all losses, claims, damages or similar events, any person who is or was an employee (other than an officer) or agent of our general partner.

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Corporate Governance

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals and maintain the trust and confidence of investors, employees, suppliers, business partners and stakeholders.

A key element for strong governance is independent members of the Board. Pursuant to the NYSE listing standards, a director will be considered independent if the Board determines that he or she does not have a material relationship with Enterprise GP or us (either directly or as a partner, unitholder or officer of an organization that has a material relationship with Enterprise GP or us). Based on the foregoing, the Board has affirmatively determined that Messrs. Andress, Barnett, Casey, McMahen, Ross, Smith and Snell are "independent" directors under the NYSE rules.

Because we are a limited partnership and meet the definition of a "controlled company" under the listing standards of the NYSE, we are not required to comply with certain requirements of the NYSE. In particular, we are not required to comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board of our general partner be comprised of a majority of independent directors. In addition, we have elected to not comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board of Enterprise GP maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Code of Conduct and Ethics and Corporate Governance Guidelines

Enterprise GP has adopted a "Code of Conduct" that applies to its directors, officers and employees. This code sets out our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance on complying with the code, the reporting of compliance issues, and discipline for violations of the code. The Code of Conduct also establishes policies applicable to our CEO, CFO, principal accounting officer and senior financial and other managers to prevent wrongdoing and to promote honest and ethical conduct, including ethical handling of actual and apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications, and prompt internal reporting of violations of the code (and thus accountability for adherence to the code). Employees are required to periodically certify their understanding and compliance with the Code of Conduct.

Governance guidelines, together with applicable committee charters, provide the framework for effective governance. The Board has adopted the "Governance Guidelines of Enterprise Products Partners," which address several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibilities of the Audit and Conflicts Committee (the "Audit Committee") and the Governance Committee, the conduct and frequency of Board and committee meetings, management succession plans, director access to management and outside advisors, director compensation, director and executive officer equity ownership, director orientation and continuing education, and annual self-evaluation of the Board. The Board recognizes that effective governance is an on-going process, and thus, it will review the Governance Guidelines of Enterprise Products Partners annually or more often as deemed necessary.

Audit Committee

The purpose of the Board's Audit Committee is to address audit and conflicts-related matters. In accordance with NYSE rules and the Securities Exchange Act of 1934, the Board has named three of its members to serve on its Audit Committee. The members of the Audit Committee must have a basic understanding of finance and accounting matters and be able to read and understand fundamental financial statements, and at least one member of the Audit Committee shall have accounting or related financial management expertise. The current members of the Audit Committee are

Messrs. McMahen (chairman), Ross and Snell, all of whom are independent directors, free from any relationship with us or any of our subsidiaries that would interfere with the exercise of independent judgment. The Board has affirmatively determined that Mr. McMahen satisfies the definition of "audit committee financial expert" as defined in Item 407(d) of Regulation S-K promulgated by the SEC.

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The primary responsibilities of the Audit Committee include (i) reviewing potential conflicts of interest, including related party transactions, (ii) monitoring the integrity of our financial reporting process and related systems of internal control, (iii) ensuring our legal and regulatory compliance and that of Enterprise GP, (iv) overseeing the independence and performance of our independent public accountant, (v) approving all services performed by our independent public accountant, (vi) providing for an avenue of communication among the independent public accountant, management, internal audit function and the Board, (vii) encouraging adherence to and continuous improvement of our policies, procedures and practices at all levels, (viii) reviewing areas of potential significant financial risk to our businesses and (ix) approving awards granted under our long-term incentive plans.

If the Board believes that a particular matter presents a conflict of interest and proposes a resolution, the Audit Committee has the authority to review such matter to determine if the proposed resolution is fair and reasonable to us. Any matters approved by the Audit Committee are conclusively deemed to be fair and reasonable to our business, approved by all of our partners and not a breach by Enterprise GP or the Board of any duties they may owe us or our unitholders.

Pursuant to its formal written charter, the Audit Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. The Audit Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

Governance Committee

The Governance Committee was established by the Board in May 2011. In accordance with its charter, the Governance Committee shall be composed of not less than three members, at least a majority of whom shall be independent directors. Currently, the Governance Committee is comprised of four independent directors: Messrs. Andress, Barnett (chairman), Casey and Smith. The primary purpose of the Board's Governance Committee is to develop and recommend to the Board a set of governance guidelines applicable to our partnership, to review such guidelines from time to time and to oversee governance matters related to our business, including Board and Committee composition, qualifications of Board candidates, director independence, succession planning and other related matters. Prior to the establishment of the Governance Committee, these responsibilities were generally handled by the Audit Committee, which was then known as the Audit, Conflicts and Governance Committee.

The Governance Committee was also established to assist in Board oversight of management's establishment and administration of our environmental, health and safety policies, procedures, programs and initiatives, and other related matters.

Like the Audit Committee, the Governance Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. In addition, the Governance Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

Investor Access to Corporate Governance Information

We provide investors access to current information relating to our governance procedures and principles, including the Code of Conduct, the Governance Guidelines of Enterprise Products Partners, the Audit Committee and Governance Committee charters, and other matters, through our Internet website, www.enterpriseproducts.com. You may also contact our Investor Relations department at (866) 230-0745 for printed copies of these documents free of charge.

NYSE Corporate Governance Listing Standards

On March 8, 2011, Mr. Creel, our CEO, certified to the NYSE (as required by Section 303A.12(a) of the NYSE Listed Company Manual) that he was not aware of any violation by us of the NYSE's Corporate Governance listing standards as of March 8, 2011.

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Executive Sessions of Non-Management Directors

The Board holds regular executive sessions in which non-management directors meet without any members of management present. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, one director is designated as the "presiding director," who is responsible for leading and facilitating such executive sessions. Currently, the presiding director is Mr. McMahen.

In accordance with NYSE rules, we have established a toll-free, confidential telephone hotline (the "Hotline") so that interested parties may communicate with the presiding director or with all the non-management directors as a group. All calls to this Hotline are reported to the chairman of the Audit Committee, who is responsible for communicating any necessary information to the other non-management directors. The number of our confidential Hotline is (877) 888-0002.

Directors and Executive Officers of Enterprise GP

The following table sets forth the name, age and position of each of the directors and executive officers of Enterprise GP at February 29, 2012. Each executive officer holds the same respective office shown below in the managing member of EPO.

Name	Age	Position with Enterprise GP
Randa Duncan Williams	50	Director
Thurmon M. Andress (1)	78	Director
Richard H. Bachmann	59	Director
E. William Barnett (1,2)	79	Director
Larry J. Casey (1)	79	Director
Michael A. Creel (3)	58	Director, President and CEO
Dr. Ralph S. Cunningham	71	Director and Chairman of the Board
W. Randall Fowler (3)	55	Director, Executive Vice President and CFO
Charles E. McMahen (4,5)	72	Director
Rex C. Ross (5)	68	Director
Edwin E. Smith (1)	80	Director
Richard S. Snell (5)	69	Director
A. James Teague (3)	66	Director, Executive Vice President and Chief Operating Officer
William Ordemann (3)	52	Executive Vice President
Lynn L. Bourdon, III (3)	50	Senior Vice President
Bryan F. Bulawa (3)	42	Senior Vice President and Treasurer
G. R. Cardillo (3)	54	Senior Vice President
James M. Collingsworth (3)	57	Senior Vice President
Stephanie C. Hildebrandt (3)	47	Senior Vice President, General Counsel and Secretary
Mark A. Hurley (3)	53	Senior Vice President
Michael J. Knesek (3)	57	Senior Vice President, Controller and Principal Accounting Officer
Christopher Skoog (3)	48	Senior Vice President
Thomas M. Zulim (3)	54	Senior Vice President

(1) Member of the Governance Committee
(2) Chairman of the Governance Committee
(3) Executive officer

(4) Chairman of the Audit Committee
(5) Member of the Audit Committee

In addition to the persons listed above, Mr. O.S. Andras serves as an honorary director of Enterprise GP. Mr. Andras' status as an honorary director is solely honorary and does not confer any of the rights, obligations, liabilities or responsibilities of a director of Enterprise GP (including any power or authority to vote on any matters as a director).

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The following information presents a brief history of the business experience of our directors and executive officers of Enterprise GP:

Randa Duncan Williams. Ms. Williams was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). She served as a director of Holdings GP from May 2007 to November 2010. She was elected Chairman of EPCO in May 2010, having previously served as Group Co-Chairman since 1994. Ms. Williams has served as a director of EPCO since February 1991. Prior to joining EPCO in 1994, Ms. Williams practiced law with the firms Butler & Binion and Brown, Sims, Wise & White. She currently serves on the boards of directors of Encore Bancshares and Encore Bank and also serves on the board of trustees for numerous charitable organizations.

Thurmon M. Andress. Mr. Andress was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and serves on its Governance Committee. He served as a director of Holdings GP from November 2006 to November 2010. Mr. Andress serves as the Managing Director-Houston for Breitburn Energy Company L.P. and is a former member of its Board of Directors. In 1990, he founded Andress Oil & Gas Company, serving as its President and CEO until it merged with Breitburn Energy Company L.P. in 1998. In 1982, he founded Bayou Resources, Inc. a publicly traded energy company that was sold in 1987. From 2002 through December 2009, Mr. Andress served as a member of the Board of Directors of Edge Petroleum Corp. (including its Governance and Compensation Committees). In October 2009, Edge Petroleum Corp. filed a voluntary petition under Chapter 11 of the U.S. Bankruptcy Code and, on December 31, 2009, completed the sale of substantially all of its assets to Mariner Energy, Inc. Mr. Andress is currently a member of the National Petroleum Council and serves on the Board of Governors of Houston for the Independent Petroleum Association of America. In 1993, Mr. Andress was inducted into All American Wildcatter's, a 100-member organization dedicated to American oil and gas explorationists and producers.

Richard H. Bachmann. Mr. Bachmann was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). He served as an Executive Vice President of Holdings GP from April 2005 to November 2010 and as a director of Holdings GP from February 2006 to November 2010. He served as Chief Legal Officer and Secretary of Holdings GP from April 2005 to May 2010. Mr. Bachmann served as Executive Vice President and Chief Legal Officer of EPGP from February 1999 until November 2010 and as Secretary of EPGP from November 1999 to November 2010. He previously served as a director of EPGP from June 2000 to January 2004 and from February 2006 to May 2010.

Mr. Bachmann was elected President and CEO of EPCO in May 2010 and has served as a director since January 1999. He previously served as Secretary of EPCO from May 1999 to May 2010 and as a Group Vice Chairman of EPCO from December 2007 to May 2010. Mr. Bachmann served as a director of DEP GP from October 2006 to May 2010 and as President and CEO of DEP GP from October 2006 to April 2010. In November 2006, Mr. Bachmann was appointed as an independent manager of Constellation Energy Partners LLC. Mr. Bachmann also serves as a member of the Audit, Compensation and Nominating and Governance Committees of Constellation Energy Partners LLC and as the Chairman of its Conflicts Committee.

E. William Barnett. Mr. Barnett was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and serves as Chairman of its Governance Committee. He served as a director of EPGP from March 2005 to November 2010. Mr. Barnett practiced law with Baker Botts L.L.P. from 1958 until his retirement in 2004. In 1984, he became Managing Partner of Baker Botts L.L.P. and continued in that role for 14 years until 1998. He was Senior Counsel to the firm from 1998 until June 2004, when he retired from the firm. Mr. Barnett served as Chairman of the Board of Trustees of Rice University from 1996 to July 2005.

Mr. Barnett is a Life Trustee of The University of Texas Law School Foundation; a director of St. Luke's Episcopal Hospital; a Director Emeritus and former Chairman of the Houston Zoo, Inc. (the operating arm of the Houston Zoo); and a Director Emeritus of Baylor College of Medicine. He is a director of GenOn Energy, Inc. (a publicly traded wholesale electricity generation company) and Westlake Chemical Corporation (a publicly traded chemical company). Mr. Barnett is Chairman of the Advisory Board of the Baker Institute for Public Policy at Rice University and a Director Emeritus and former Chairman of the Greater Houston Partnership.

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Larry J. Casey. Mr. Casey was elected a director of Enterprise GP in September 2011 and serves on its Governance Committee. He previously served as a director of DEP GP from October 2006 until September 2011. Mr. Casey has been a private investor managing real estate and personal investments since he retired in 1982 from a career in the energy industry. In 1974, Mr. Casey founded Xcel Products Company, an NGL and petrochemical trading company. Also in 1974, he founded Xral Underground Storage, the first privately owned underground merchant storage facility for NGLs and specialty chemicals at Mont Belvieu, Texas. Mr. Casey sold these companies in 1982.

Michael A. Creel. Mr. Creel was elected President and CEO and a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). He served as a director of EPGP from February 2006 to November 2010 and President and CEO of EPGP from August 2007 to November 2010. Mr. Creel served as CFO of EPGP from June 2000 to August 2007, and as an Executive Vice President of EPGP from January 2001 to August 2007. Mr. Creel, a Certified Public Accountant, also served as a Senior Vice President of EPGP from November 1999 to January 2001.

Mr. Creel previously served as a director of Holdings GP from October 2009 to May 2010 and as a director of DEP GP from October 2006 to May 2010. He previously served as President, CEO and a director of Holdings GP from August 2005 through August 2007. From October 2006 to August 2007, he served as Executive Vice President and CFO of DEP GP. From October 2005 through December 2009, Mr. Creel served as a director of Edge Petroleum Corporation, a publicly traded oil and natural gas exploration and production company, which filed a voluntary petition under Chapter 11 of the U.S. Bankruptcy Code in October 2009 and, on December 31, 2009, completed the sale of substantially all of its assets to Mariner Energy, Inc.

Dr. Ralph S. Cunningham. Dr. Cunningham was elected a director and Chairman of the Board of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). Dr. Cunningham served as a director and as the President and CEO of Holdings GP from August 2007 until November 2010. He served as a director of EPGP from February 2006 to May 2010, having previously served as a director of EPGP from April 1998 until March 2005. In addition to these duties, Dr. Cunningham served as Group Executive Vice President and Chief Operating Officer of EPGP from December 2005 to August 2007 and Interim President and Interim CEO from June 2007 to August 2007. Dr. Cunningham served as a director of DEP GP from August 2007 to May 2010. He served as Chairman and a director of TEPPCO GP from March 2005 until November 2005.

Dr. Cunningham was elected Vice Chairman of EPCO in May 2010 and a director in March 2006, having previously served as Group Vice Chairman of EPCO from December 2007 to May 2010 and as a director of EPCO from 1987 to 1997. He serves as a director of Tetra Technologies, Inc. and Agrium, Inc. In addition, Dr. Cunningham serves as a director and the Chairman of the Safety, Environmental and Responsibility Committee of Cenovus Energy Inc. Dr. Cunningham retired in 1997 from CITGO Petroleum Corporation, where he served as President and CEO since 1995. Dr. Cunningham also served as a director of LE GP, LLC (the general partner of Energy Transfer Equity, L.P.) from December 2009 to November 2010.

W. Randall Fowler. Mr. Fowler was elected a director of Enterprise GP in September 2011. He was named an Executive Vice President and the CFO of Enterprise GP in November 2010 (upon consummation of the Holdings Merger), having previously served as Executive Vice President and CFO of EPGP from August 2007 to November 2010. He also served as President and CEO of DEP GP from April 2010 until September 2011 and as Executive Vice President and CFO of DEP GP from August 2007 to April 2010. He served as a director of DEP GP from September 2006 until September 2011.

Mr. Fowler served as Senior Vice President and Treasurer of EPGP from February 2005 to August 2007 and of DEP GP from October 2006 to August 2007. Mr. Fowler also previously served as a director of EPGP and of Holdings GP from February 2006 to May 2010. Mr. Fowler also served as Senior Vice President and CFO of Holdings GP from August 2005 to August 2007. Mr. Fowler was elected Vice Chairman and CFO of EPCO in May 2010. He previously served as President and CEO of EPCO from December 2007 to May 2010 and as its CFO from April 2005 to December 2007.

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Mr. Fowler, a Certified Public Accountant (inactive), joined us as Director of Investor Relations in January 1999. Mr. Fowler also serves as Chairman of the Board of the National Association of Publicly Traded Partnerships. He also serves on the Advisory Board for the College of Business at Louisiana Tech University.

Charles E. McMahen. Mr. McMahen was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and serves as Chairman of its Audit Committee. He served as a director of Holdings GP from August 2005 to November 2010. Mr. McMahen served as Vice Chairman of Compass Bank from March 1999 until December 2003 and served as Vice Chairman of Compass Bancshares from April 2001 until his retirement in December 2003. Mr. McMahen also served as Chairman and CEO of Compass Banks of Texas from March 1990 until March 1999. Mr. McMahen has served as a director of Compass Bancshares, and its successor, BBVA Compass Bank (a wholly owned subsidiary of BBVA), since 2001. He also serves as a director for the following additional wholly owned subsidiaries of BBVA: (i) BBVA USA Bancshares (a bank holding company for BBVA's North American banking operations); and (ii) BBVA Compass Bancshares, Inc. (a bank holding company for BBVA Compass Bank). Mr. McMahen serves on the Audit Committee for BBVA Compass Bancshares, Inc. and as Chairman of the Risk Committee for BBVA Compass Bank. Mr. McMahen served as Chairman of the Board of Regents of the University of Houston from September 1998 to August 2000.

Rex C. Ross. Mr. Ross was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and is a member of its Audit Committee. He served as a director of EPGP from October 2006 until November 2010. Until July 2009, Mr. Ross served as a director of Schlumberger Technology Corporation, the holding company for all Schlumberger Limited assets and entities in the U.S. Prior to his retirement from Schlumberger Limited in May 2004, Mr. Ross held a number of executive management positions during his 11-year career with the company, including President of Schlumberger Oilfield Services North America; President, Schlumberger GeoQuest; and President of SchlumbergerSema North & South America. Mr. Ross also serves on the Board of Directors of Gulfmark Offshore, Inc. (a publicly traded offshore marine services company) and is a member of its Governance & Nominating Committee and its Compensation Committee.

Edwin E. Smith. Mr. Smith was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and is a member of its Governance Committee. He served as a director of Holdings GP from August 2005 to November 2010. Mr. Smith has been a private investor since he retired from Allied Bank of Texas in 1989 after a 31-year career in banking. Mr. Smith serves as a director of Encore Bank and previously served as a director of EPCO from 1987 until 1997.

Richard S. Snell. Mr. Snell, a Certified Public Accountant, was elected a director of Enterprise GP in September 2011 and serves on its Audit Committee. He previously served as a director of DEP GP from January 2010 until September 2011. Mr. Snell also served as a director of TEPPCO GP from January 2006 until October 2009. From June 2000 until February 2006, he served as a director of EPGP. He is senior counsel with the law firm of Thompson & Knight LLP, having been with the firm since 2000. Prior to his position with Thompson & Knight LLP, he worked as an attorney for the Snell & Smith, P.C. law firm from its founding in 1993 until 2000.

A. James Teague. Mr. Teague was elected an Executive Vice President and the Chief Operating Officer and a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). He served as Executive Vice President of EPGP from November 1999 to November 2010 and additionally as a director from July 2008 to November 2010 and as Chief Operating Officer from September 2010 to November 2010. In addition, he served as EPGP's Chief Commercial Officer from July 2008 until September 2010. He served as Executive Vice President and Chief Commercial Officer of DEP GP from July 2008 until September 2011. He previously served as a director of DEP GP from July 2008 to May 2010 and as a director of Holdings GP from October 2009 to May 2010. Mr. Teague joined Enterprise in connection with its purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. From 1998 to 1999, Mr. Teague served as President of Tejas Natural Gas Liquids, LLC, then an affiliate of Shell. From 1997 to 1998, he was President of Marketing and Trading for Mapco Inc.

William Ordemann. Mr. Ordemann was elected an Executive Vice President of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). He previously served as EPGP's Chief Operating Officer from August 2007 until September 2010 and as its Executive Vice President from August 2007 to November 2010. Mr. Ordemann also served as an Executive Vice President of Holdings GP from August 2007 to November

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2010 and as an Executive Vice President of DEP GP from August 2007 to September 2011. He previously served as a Senior Vice President of EPGP from September 2001 to August 2007 and was a Vice President of EPGP from October 1999 to September 2001. Mr. Ordemann joined Enterprise in connection with its purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. Prior to joining Enterprise, he was a Vice President of Shell Midstream Enterprises, LLC from January 1997 to February 1998, and Vice President of Tejas Natural Gas Liquids, LLC from February 1998 to September 1999.

Lynn L. Bourdon, III. Mr. Bourdon was elected a Senior Vice President (Supply & Marketing) of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). He served as Senior Vice President (Supply & Marketing) of EPGP from 2004 to November 2010 after serving as Senior Vice President and Chief Commercial Officer with Orion Refining Corporation from 2001 to 2003 and as a Partner in En*Vantage, Inc. from 1999 to 2001. In May 2003, Orion Refining Corporation filed a voluntary petition under Chapter 11 of the U.S. Bankruptcy Code. Mr. Bourdon served as Senior Vice President of Commercial Operations for PG&E Gas Transmission from 1997 to 1999 and Vice President, NGL Marketing & Development at its predecessor company, Valero, from 1996 to 1997. Earlier in his career, Mr. Bourdon served 12 years with Dow Chemical Company in its engineering, business and commercial areas.

Bryan F. Bulawa. Mr. Bulawa was elected a Senior Vice President and the Treasurer of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). He previously served as Senior Vice President, CFO and Treasurer of DEP GP from April 2010 until September 2011 and a director of DEP GP from February 2011 to September 2011. He also served as Senior Vice President and Treasurer of EPGP and Holdings GP from October 2009 to November 2010, as Senior Vice President and Treasurer of DEP GP from October 2009 to April 2010, and as Vice President and Treasurer of EPGP from July 2007 to October 2009. He has also served as Senior Vice President and Treasurer of EPCO since May 2010. Prior to joining Enterprise, Mr. Bulawa spent 13 years at Scotia Capital, where he last served as director of the firm's U.S. Energy Corporate Finance and Distribution group.

G. R. Cardillo. Mr. Cardillo was elected a Senior Vice President (Propylene & Marine) of Enterprise GP in February 2011. Mr. Cardillo joined us in connection with our purchase of certain petrochemical storage and propylene fractionation assets from affiliates of Ultramar Diamond Shamrock Corp. and Koch Industries Inc. ("Diamond Koch") in 2002. From 2000 to 2002, Mr. Cardillo served as a Vice President in charge of propylene commercial activities for Diamond Koch. Mr. Cardillo served as a Vice President of EPGP from November 2004 to November 2010 and of Enterprise GP from November 2010 to February 2011. Mr. Cardillo has been an integral part of our Petrochemicals management team since joining us in 2002 and assumed leadership of this commercial function in June 2008. He assumed leadership of our marine services business in July 2010.

James M. Collingsworth. Mr. Collingsworth was elected a Senior Vice President (Regulated Pipelines & Gas Storage) of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). He served as Vice President of EPGP from November 2001 to November 2002 and Senior Vice President from November 2002 until November 2010. Previously, he served as a board member of Texaco Canada Petroleum Inc. from July 1998 to October 2001 and was employed by Texaco from 1991 to 2001 in various management positions, including Senior Vice President of NGL Assets and Business Services from July 1998 to October 2001. Prior to joining Texaco, Mr. Collingsworth was director of feedstocks for Rexene Petrochemical Company from 1988 to 1991 and served in the MAPCO, Inc. organization from 1973 to 1988 in various capacities including customer service and business development manager of the Mid-America and Seminole pipelines.

Stephanie C. Hildebrandt. Ms. Hildebrandt was elected a Senior Vice President and the General Counsel of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and served as Senior Vice President and General Counsel of EPGP and Holdings GP from May 2010 to November 2010. Ms. Hildebrandt served as Senior Vice President, Chief Legal Officer and Secretary of DEP GP from April 2010 until September 2011, having previously served as Vice President and General Counsel of EPGP from October 2009 to May 2010, as Vice President and Deputy General Counsel of EPGP from 2006 to 2009, and as Deputy General Counsel of EPGP from 2004 to 2006. Prior to joining us, Ms. Hildebrandt practiced law for three years at El Paso Corporation and for 12 years at Texaco Inc.

Mark A. Hurley. Mr. Hurley was elected a Senior Vice President (Crude Oil & Offshore) of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). He previously served as Senior Vice President

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(Crude Oil & Offshore) for EPGP from March 2010 to November 2010. Prior to joining us, Mr. Hurley was an employee of Shell and recently served as President of Shell Pipeline Company, which is a crude oil, refined products and natural gas storage and transportation company. Mr. Hurley began his career with Shell in process engineering positions at refineries in Louisiana and California. During his tenure with Shell, he held key leadership roles in refinery and lubricant plant operations, marketing, sales, product supply planning and trading, with both U.S. and global responsibilities. As President of Shell Pipeline Company for five years, Mr. Hurley had ultimate responsibility for its profitability, operations, strategy, business development and capital project development.

Michael J. Knesek. Mr. Knesek, a Certified Public Accountant, was elected the Senior Vice President, Controller and Principal Accounting Officer of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). From February 2005 to November 2010, Mr. Knesek served as Senior Vice President of EPGP, having previously served as a Vice President of EPGP since August 2000. Mr. Knesek served as the Principal Accounting Officer and Controller of Holdings GP from August 2005 to November 2010 and served in the same capacity for DEP GP from September 2006 to September 2011. He served as the Principal Accounting Officer and Controller of EPGP from August 2000 to November 2010. He also served as Senior Vice President of DEP GP from September 2006 to September 2011. Mr. Knesek has been the Controller of EPCO since 1990 and currently serves as one of its Senior Vice Presidents.

Christopher R. Skoog. Mr. Skoog was elected Senior Vice President (Natural Gas Services & Marketing) of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). He joined us in July 2007 as Senior Vice President of EPGP to develop and lead our Natural Gas Services and Marketing group. In July 2008, he also assumed responsibility for Enterprise’s non-regulated and intrastate natural gas pipeline and storage businesses. From 1995 to July 2007, he served in various executive positions at ONEOK, Inc. and ONEOK Partners L.P. He led ONEOK Energy Services from 1995 to 2005, and held senior executive positions at ONEOK from 2005 to 2007.

Thomas M. Zulim. Since July 2008, Mr. Zulim has served as a Senior Vice President of EPCO, and was elected Senior Vice President (Unregulated NGL Business) of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). Mr. Zulim previously served as a Senior Vice President of EPGP from July 2008 to November 2010. From March 2006 to July 2008, Mr. Zulim served as Senior Vice President, Human Resources, for both EPGP and EPCO, and served as Vice President, Human Resources, for both EPGP and EPCO from December 2004 to March 2006. He joined EPCO in 1999 as Director of Business Management for the NGL Fractionation business. Mr. Zulim came to EPCO from Shell Oil Company where, as an attorney, he practiced labor and employment law nationally for several years before joining Shell Midstream Enterprises in 1996 as Director of Business Development for its natural gas processing and NGL fractionation businesses. Mr. Zulim resumed practicing law with EPCO’s legal group in January 2002 until December 2004.

Director Experience, Qualifications, Attributes and Skills

The following is a brief discussion of the experience, qualifications, attributes or skills that led to the conclusion that each of the following persons should serve as a director of our general partner.

Six of our directors are current employees of EPCO and officers of our general partner or its affiliates. Each of these directors has significant experience in our industry as executive officers as well as other qualifications, attributes and skills. These include: for Ms. Williams, legal and community involvement with numerous charitable organizations, and active involvement in EPCO’s businesses, including ownership and management of Enterprise’s businesses; for Dr. Cunningham, over 45 years of refined products, chemicals and midstream businesses; for Mr. Bachmann, over 30 years of experience with our midstream assets, including legal, regulatory, contracts and mergers and acquisitions and, for over the last ten years, as a member of Enterprise’s executive management team; for Mr. Creel, over 30 years of management experience with midstream assets, for both third parties and Enterprise, including finance and accounting (certified public accountant) and more than seven years of management experience in the financial industry; for Mr. Fowler, over 10 years of experience with our midstream assets, including finance accounting (inactive certified public accountant) and investor public relations and, for over the last seven years, as a member of our executive management team; and for Mr. Teague, over 40 years of commercial management of midstream assets and marketing and trading activities, both for third parties and for the Enterprise's businesses.

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Our seven outside directors also have significant experience in our industry in a variety of capacities, as well as other qualifications, attributes and skills. These include: for Mr. Andress, oil and gas exploration and production; for Mr. Barnett, legal, regulatory and management skills as a former managing partner of an international law firm; for Mr. Casey, executive management of NGL and petrochemicals trading, and related storage businesses; for Mr. McMahen, banking and finance; for Mr. Ross, executive management of oilfield services businesses; for Mr. Smith, banking and investments; and for Mr. Snell, legal, review of accounting and financial statements and director oversight functions for other midstream assets of our affiliates.

Section 16(a) Beneficial Ownership Reporting Compliance

Under federal securities laws, directors and executive officers of Enterprise GP and any persons holding more than 10% of our common units are required to report their beneficial ownership of common units and any changes in their beneficial ownership levels to us and the SEC. Specific due dates for these reports have been established by regulation, and we are required to disclose in this annual report any failure to file this information within the specified timeframes. All such reporting was done in a timely manner in 2011, except that (a) on May 17, 2011, Mr. Teague filed one late Form 4 reporting (i) one purchase transaction that he inadvertently failed to report during 2005, (ii) one purchase transaction that he inadvertently failed to report during 2009 and (iii) one gift transaction in 2008 that he inadvertently failed to report by the Form 5 reporting deadline in February 2009; (b) on February 3, 2012, Mr. Teague filed one late Form 4 reporting one purchase transaction by his spouse that he inadvertently failed to report during 2008; and (c) on October 25, 2011, Mr. Andress filed one late Form 4 reporting a Rule 16b-3(d) acquisition transaction that he inadvertently failed to timely report by the reporting deadline in September 2011.

Item 11. Executive Compensation.

Executive Officer Compensation

We do not directly employ any of the persons responsible for managing our business. Instead, we are managed by our general partner, the executive officers of which are employees of EPCO. Our management, administrative and operating functions are primarily performed by employees of EPCO pursuant to the ASA. Pursuant to the ASA, we reimburse EPCO for 100% of its compensation costs related to employment of personnel working on our behalf. For information regarding the ASA, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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Summary Compensation Table

The following table presents total compensation amounts paid, accrued or otherwise expensed by us with respect to the years ended December 31, 2011, 2010 and 2009 for the CEO, the CFO, and the three other most highly compensated executive officers of our general partner. Collectively, these individuals were our "named executive officers" for 2011. The compensation amounts presented below include amounts allocated to Holdings prior to the Holdings Merger in November 2010.

Name and Principal Position	Year	Cash Salary ($)	Cash Bonus ($) (1)	Unit Awards ($) (2)	Option Awards ($) (3)	All Other Comp. ($) (4)	Total ($)
Michael A. Creel	2011	$707,275	$1,425,000	$2,640,354	$--	$530,461	$5,303,090
(President and CEO)	2010	607,187	1,046,875	2,091,096	208,905	388,681	4,342,744
	2009	580,000	1,280,000	2,616,695	718,920	216,630	5,412,245
W. Randall Fowler	2011	402,905	562,500	1,442,100	--	287,595	2,695,100
(Executive Vice President and CFO)	2010	275,625	262,500	822,885	87,044	166,070	1,614,124
	2009	206,719	354,375	973,475	242,422	80,271	1,857,262
A. James Teague	2011	665,113	1,300,000	1,922,800	--	412,067	4,299,980
(Executive Vice President and	2010	650,000	650,000	1,710,310	174,087	372,446	3,556,843
Chief Operating Officer)	2009	650,000	950,000	2,445,585	665,400	233,747	4,944,732
William Ordemann	2011	414,612	250,000	1,311,000	--	329,170	2,304,782
(Executive Vice President)	2010	406,300	250,000	1,090,726	174,087	283,173	2,204,286
	2009	395,200	310,000	1,643,242	565,950	220,470	3,134,862
Lynn L. Bourdon, III	2011	387,656	400,000	961,400	--	171,128	1,920,184
	2010	379,219	300,000	451,780	87,044	190,440	1,408,483
	2009	323,208	265,000	726,297	332,500	132,273	1,779,278

(1) Amounts represent discretionary annual cash awards accrued with respect to the years presented. Cash awards are paid in February of the following year (e.g., the cash awards with respect to 2011 were paid in February 2012).
(2) Amounts represent our estimated share of the aggregate grant date fair value of restricted common unit awards and limited partnership interests in the Employee Partnerships granted during each year presented. For information about assumptions made in the valuation of these awards and limited partner interests, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report, the applicable disclosures of which are incorporated by reference into this Item 11.
(3) Amounts represent our estimated share of the aggregate grant date fair value of unit option awards granted during each year presented. For information about assumptions made in the valuation of these awards, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report, the applicable disclosures of which are incorporated by reference into this Item 11.
(4) Amounts include (i) matching contributions under funded, qualified, defined contribution retirement plans, (ii) quarterly distributions paid on incentive plan awards, (iii) the imputed value of life insurance premiums paid on behalf of the officer and (iv) other amounts. The following table presents the components of "All Other Compensation" for each named executive officer for the year ended December 31, 2011:

	Matching Contributions Under Funded, Qualified, Defined Contribution Retirement Plans	Quarterly Distributions Paid On Incentive Plan Awards	Life Insurance Premiums	Other	Total All Other Compensation
Michael A. Creel	$ 25,603	$ 496,705	$2,206	$5,947	$ 530,461
W. Randall Fowler	20,213	261,684	1,742	3,956	287,595
A. James Teague	26,950	372,273	6,858	5,986	412,067
William Ordemann	29,400	292,577	1,242	5,951	329,170
Lynn L. Bourdon, III	24,500	140,556	810	5,262	171,128

Certain of the named executive officers perform services for other affiliates of EPCO. Under the ASA, the compensation costs of our named executive officers are allocated between us and other affiliates of EPCO based on

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the estimated amount of time that each officer spends on our consolidated businesses in any fiscal year. These percentages are reassessed at least quarterly.

The following table presents the average approximate amount of time devoted by each of our named executive officers to our consolidated businesses, which included Duncan Energy Partners prior to the Duncan Merger in September 2011, and to EPCO and its other affiliates during each of the years presented. As presented in the table, the percentages listed for Enterprise Products Partners have been retrospectively adjusted to include the amount of time each named executive officer devoted to Holdings prior to the Holdings Merger.

Named Executive Officer	Year	Enterprise Products Partners	EPCO and other affiliates	Total Time Allocated
Michael A. Creel (CEO)	2011	95%	5%	100%
	2010	84%	16%	100%
	2009	80%	20%	100%
W. Randall Fowler (CFO)	2011	75%	25%	100%
	2010	53%	47%	100%
	2009	50%	50%	100%
A. James Teague	2011	100%	--	100%
	2010	100%	--	100%
	2009	100%	--	100%
William Ordemann	2011	100%	--	100%
	2010	100%	--	100%
	2009	100%	--	100%
Lynn L. Bourdon, III	2011	100%	--	100%
	2010	100%	--	100%
	2009	100%	--	100%

Compensation Discussion and Analysis

With respect to our named executive officers, compensation paid or awarded by us for the last three fiscal years reflects only that portion of compensation paid by EPCO and allocated to us pursuant to the ASA, including an allocation of a portion of the cost of equity-based long-term incentive plans of EPCO. The EPCO Trustees control EPCO and provide recommendations with respect to the compensation of our CEO. As discussed further below, the Audit Committee of our general partner was given ultimate decision-making authority with respect to 2011 compensation to be paid to our CEO, and our CEO was given ultimate decision-making authority with respect to 2011 compensation to be paid to our other named executive officers. The following elements of compensation, and EPCO's decisions with respect to determination of payments, are not subject to approvals by the Board or the Audit Committee of our general partner, except in the case of compensation paid to our CEO (as described below). Neither EPCO nor our general partner has a separate compensation committee; however, equity awards granted under EPCO's long-term incentive plans are approved by the Audit Committee.

As discussed below, the elements of EPCO's compensation program, along with EPCO's other incentives (e.g., benefits, work environment and career development), are intended to provide a total rewards package to employees. The objectives of EPCO's compensation program are to provide competitive compensation opportunities that will align and drive employee performance toward the creation of sustained long-term unitholder value. Our compensation program allows us to attract, motivate and retain high quality talent with the skills and competencies we require. The compensation package is designed to reward contributions by employees in support of the business strategies of EPCO and its affiliates at both our partnership and individual levels. With respect to the three years ended December 31, 2011, EPCO's compensation package for named executive officers did not include any elements based on targeted performance-related criteria.

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The primary elements of EPCO's compensation program are a combination of annual cash and long-term equity-based incentive compensation. For the three years ended December 31, 2011, the elements of compensation for the named executive officers consisted of annual cash base salary, discretionary annual cash bonus awards, awards under long-term incentive arrangements and other compensation, including very limited perquisites.

In order to assist our CEO, EPCO and the Audit Committee with compensation decisions, EPCO's senior vice president of Human Resources formulates preliminary compensation recommendations for each of the named executive officers, including our CEO. With respect to compensation to be paid to our CEO, the EPCO Trustees consider such preliminary recommendation and make revisions, if appropriate. Afterwards, the EPCO Trustees and EPCO's senior vice president of Human Resources present the revised CEO compensation recommendation to the members of the Audit Committee, which consider the recommendation and then make a final determination regarding compensation of our CEO. In making their final determination, the Audit Committee may discuss the recommendation with EPCO's senior vice president of Human Resources, request to discuss the recommendations with EPCO's compensation consultant, if any, and/or retain its own compensation consultant.

With respect to compensation to be paid to named executive officers other than our CEO, the CEO considers the preliminary recommendations of EPCO's senior vice president of Human Resources and makes revisions, if appropriate. The CEO makes a final determination regarding compensation of each named executive officer (other than the CEO himself).

In making these compensation decisions, EPCO considers market data for determining relevant compensation levels and compensation program elements through the review of and, in certain cases, participation in, relevant compensation surveys and reports. These surveys and reports are conducted and prepared by a third-party compensation consultant.

In 2011, EPCO engaged Meridian Compensation Partners, LLC (the "Consultant") to review executive compensation relative to our industry. The Consultant provided comparative market data on compensation practices and programs for executive level positions based on an analysis of industry competitors and other large companies. The market data for industry competitors included information from Atmos Energy Corporation; CenterPoint Energy, Inc.; CMS Energy Corporation; Constellation Energy Group, Inc.; Dominion Resources, Inc.; El Paso Corporation; Enbridge Energy Partners, L.P.; Energy Transfer Partners, L.P.; NiSource Inc.; NuStar Energy L.P.; ONEOK, Inc.; Plains All American Pipeline, L.P.; Spectra Energy Corp.; The Williams Companies, Inc.; and TransCanada Corporation. The market data for other large companies included 51 entities across multiple industries ranging in revenue size from $80 billion to $15 billion, including well known companies such as The Procter & Gamble Company; The Home Depot, Inc.; Archer Daniels Midland Company; Target Corporation; and The Boeing Company, among others.

Neither we, nor EPCO, which engages the Consultant, are aware of the specific data of the companies included in the Consultant's proprietary database for specific positions. EPCO uses the information provided in the Consultant's analysis to gauge whether compensation levels reported by the Consultant and the general ranges of compensation for EPCO employees in similar positions are comparable, but that comparison is only a factor taken into consideration and may or may not impact compensation of our named executive officers, for which our Audit Committee (in the case of our CEO's compensation) or our CEO (in the case of compensation to be paid to our other named executive officers) has the ultimate decision-making authority. EPCO does not otherwise engage in benchmarking for the named executive officers' positions.

The Audit Committee, our CEO and EPCO do not use any formula or specific performance-based criteria in determining the compensation of our named executive officers for services they perform for us; rather, the Audit Committee or our CEO (as applicable) and EPCO determine an appropriate level and mix of compensation on a case-by-case basis. Further, there is no established policy or target for the allocation between either cash and non-cash or short-term and long-term incentive compensation. However, some considerations that the Audit Committee or our CEO (as applicable) may take into account in making the case-by-case compensation determinations include total value of all elements of compensation and the appropriate balance of internal pay equity among executive officers. The Audit Committee, our CEO and EPCO also consider individual performance, levels of responsibility and value to the organization. All compensation determinations are subjective and discretionary and, as noted above, subject to the ultimate decision-making authority of the Audit Committee or the CEO (as applicable), except for equity awards under EPCO's long-term incentive plans, as discussed below.

We believe that the absence of specific performance-based criteria associated with our cash compensation and equity awards, and the long-term nature of our equity awards, has the effect of discouraging excessive risk taking by our executive officers in order to reach certain targets. Further, the practice of making compensation decisions on a case-by-case basis permits consideration of flexible criteria, including current overall market conditions.

Base salaries of our named executive officers prior to 2010 were previously determined by Mr. Duncan without consultation with the Audit Committee. During 2010 and 2011, changes in the base salaries of our named executive officers were largely budget-driven and made consistent relative to increases in the base salaries of our other executive officers.

The discretionary cash bonus awards paid to each of our named executive officers with respect to 2010 and 2011 were determined by consultation, as appropriate, among the EPCO Trustees, our CEO and EPCO's senior vice president of Human Resources, subject to final determination by the Audit Committee (in the case of our CEO's cash bonus awards) and our CEO (in the case of cash bonus awards to be paid to our other named executive officers). These cash bonus awards, in combination with annual base salaries, are intended to yield competitive total cash compensation levels for the named executive officers and drive performance in support of our business strategies, as well as the performance of other EPCO affiliates for which the named executive officers may perform services. It is EPCO's general policy to pay these awards in February of the following year. For 2010 and 2011, the discretionary cash bonuses reflected the Audit Committee's (with respect to our CEO) and our CEO's (with respect to the other named executive officers) general consideration of our financial performance for those periods, without any weight or formula given to any specific financial performance measures, as well as their subjective judgment of each named executive officer's general contributions in connection with our performance, again without any weight or formula given to any specific individual contribution or accomplishments. The levels of cash bonuses were also based on the level and position of such named executive officers and the relative compensation paid to our other executive officers.

The awards granted under EPCO's long-term incentive plans to our named executive officers during 2010 and 2011 were determined by consultation among the EPCO Trustees, our CEO and EPCO's senior vice president of Human Resources, and were approved by the Audit Committee. The levels of EPCO's long-term incentive plan awards to our named executive officers during 2010 and 2011 also reflected the Audit Committee's and our CEO's (with respect to the other named executive officers) general consideration of our financial performance for those periods, without any weight or formula given to any specific financial performance measures, as well as their subjective judgment of each named executive officer's general contributions in connection with our performance, again without any weight or formula given to any specific individual contribution or accomplishments. The levels of long-term incentive awards were also based on the level and position of such named executive officers and the relative compensation paid to our other executive officers.

EPCO expects to continue its policy of paying for limited perquisites attributable to our named executive officers. EPCO also makes matching contributions under its defined contribution plans for the benefit of our named executive officers in the same manner as it does for other EPCO employees.

EPCO does not offer our named executive officers a defined benefit pension plan. Also, none of our named executive officers had nonqualified deferred compensation during the three years ended December 31, 2011.

In August 2010, the Employee Partnerships were liquidated with the consent of EPCO (in its capacity as the general partner of each Employee Partnership) and the Class A and Class B limited partners thereof, in accordance with the terms of each Employee Partnership's partnership agreement. Upon the liquidation of each Employee Partnership, the assets of such Employee Partnership were distributed to the Class A and B limited partners thereof. As a result, the

Class B limited partners of each Employee Partnership, which included our named executive officers, received a liquidating distribution in 2010 of partnership assets consisting of limited partner interests in either us or Holdings.

In the fourth quarter of 2010, EPCO entered into retention agreements with each of the named executive

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officers to reinforce and encourage the continued dedication of such officers to EPCO and us as a member of our executive management team and to assure that we and EPCO will have the services of the executives in the foreseeable future. Pursuant to the retention agreements, Messrs. Creel, Fowler, Teague, Ordemann and Bourdon will be entitled to a cash retention payment of $10 million, $5 million, $10 million, $2.5 million and $2.5 million, respectively, less applicable withholding taxes (as applicable to each person, the “Retention Payment”) following the completion of 48 months of continuous employment with EPCO from the effective date of each retention agreement (the “Retention Period”). We record an allocated portion of such costs based on the approximate amount of time each officer spends on our consolidated business activities. The effective date of the retention agreements for Mr. Creel, Mr. Fowler and Mr. Teague was December 1, 2010. The effective date of the retention agreements for Mr. Ordemann and Mr. Bourdon was October 1, 2010.

Notwithstanding the required Retention Period, if at any time between 24 months and 48 months after December 1, 2010 (i.e., the period of continuous employment from December 1, 2010 until such time being referred to as the “Performance Period”), Mr. Teague designates a candidate to serve as Chief Operating Officer of Enterprise GP and such candidate is determined by the Audit Committee to be satisfactory and is hired by EPCO, then Mr. Teague will be entitled to a cash performance payment of the greater of (a) $6 million or (b) $10 million times (i) the number of months of Mr. Teague’s Performance Period, divided by (ii) 48 (the “Performance Payment”). Pursuant to his retention agreement, Mr. Teague is eligible to earn and receive either the Performance Payment or the Retention Payment, but not both.

Notwithstanding the Retention Period described above, each of the named executive officers will receive, or in the event of his death, his designated beneficiary will receive, unless otherwise required by law, his applicable Retention Payment in the event of an involuntary termination of his employment prior to the end of his Retention Period for specified reasons, including death, disability or termination of his employment by EPCO other than for “cause” (as defined in the applicable retention agreement) in connection with his job elimination, a business reorganization, or a sale of EPCO or us. The Retention Payment is payable in full within 30 days of such qualifying termination. In the event the named executive officer is paid his Retention Payment in connection with an involuntary termination as described above, he agrees that, for a period equal to the lesser of (i) 18 months after the date of the event which gives rise to the Retention Payment or (ii) the remainder of the Retention Period (as if the retention agreement were in full force and effect for the full Retention Period), he will not solicit or induce, either directly or indirectly, any of our employees to cease employment with EPCO.

Any Retention Payment or Performance Payment (with respect to Mr. Teague) is in addition to any discretionary incentive compensation that EPCO or any of its affiliates may, in its sole discretion, grant or have in place from time to time.

Although the retention agreements, restricted common unit awards and unit option awards are entered into with EPCO, all or a portion of the compensation related to these agreements may be allocated to us in accordance with the ASA by and among EPCO, us and the other parties thereto.

We believe that each of the base salary, discretionary cash bonus awards, long-term incentive awards and retention agreements, as applicable, fit the overall compensation objectives of us and of EPCO and are designed to avoid risks that are likely to conflict with our risk management policies.

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Grants of Plan-Based Awards in Fiscal Year 2011

The following table presents information concerning each grant of a plan-based award made to a named executive officer in 2011 for which we will be allocated by EPCO our pro rata share of the related expense under the ASA. The restricted common unit awards granted during 2011 were under EPCO's long-term incentive plans. No option awards were granted during 2011. See the following section, "Summary of Long-Term Incentive Arrangements Underlying 2011 Award Grants," for information regarding the long-term incentive plans under which these awards were granted.

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#)	Target (#)	Maximum (#)	Exercise or Base Price of Option Awards ($/Unit)	Grant Date Fair Value of Unit and Option Awards ($) (1)
Restricted common unit awards: (2)						
Michael A. Creel (CEO)	2/22/11	--	63,600	--	--	$ 2,640,354
W. Randall Fowler (CFO)	2/22/11	--	44,000	--	--	1,442,100
A. James Teague	2/22/11	--	44,000	--	--	1,922,800
William Ordemann	2/22/11	--	30,000	--	--	1,311,000
Lynn L. Bourdon, III	2/22/11	--	22,000	--	--	961,400

(1) Amounts presented reflect that portion of grant date fair value allocable to us based on the average percentage of time each named executive officer spent on our consolidated businesses during 2011. Based on current allocations, we estimate that the consolidated compensation expense we record for each named executive officer with respect to these awards will approximate these amounts over the vesting period. The closing price of our common units on February 22, 2011 was $43.70 per unit.
(2) Awards granted to the named executive officers during 2011 were made under either the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan") or the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan").

The grant date fair value amounts presented in the table are based on certain assumptions and considerations made by management. See Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our fair value assumptions made in connection with equity-based compensation.

Summary of Long-Term Incentive Arrangements Underlying 2011 Award Grants

The following information summarizes the principal types of awards granted to our named executive officers under EPCO's long-term incentive plans during 2011. These plans provide for incentive awards to EPCO's key employees who perform management, administrative or operational functions for us or our affiliates.

Awards granted under the 1998 Plan may be in the form of unit options, restricted common units, phantom units and distribution equivalent rights ("DERs"). Awards granted under the 2008 Plan may be in the form of unit options, restricted common units, phantom units, unit appreciation rights (“UARs”) and DERs. As of December 31, 2011, no phantom unit awards, UARs or associated DERs have been granted under the EPCO plans to the named executive officers.

Restricted common unit awards. Restricted common unit awards allow recipients to acquire our common units (at no cost to the recipient apart from service or other conditions) once a defined vesting period expires, subject to customary forfeiture provisions. For awards granted prior to 2010, the restrictions on such awards generally lapse four years from the date of grant. Beginning in 2010, new restricted common unit grants generally vest at a rate of 25% per year beginning one year after the grant date. The fair value of restricted common units is based on the market price per unit of our common units on the date of grant. For financial statement purposes, compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures. Each recipient is also entitled to quarterly cash distributions equal to the product of the number of restricted common units outstanding for the participant and the quarterly cash distribution per common unit paid by us.

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Unit option awards. Non-qualified incentive options to purchase a fixed number of our common units may be granted to key employees of EPCO. When issued, the exercise price of each option grant may be no less than the market price of our common units on the date of grant. In general, options granted under the EPCO plans have a vesting period of four years from the date of grant and expire at the end of the calendar year following the year of vesting (e.g., an option that vested on May 29, 2011 will expire on December 31, 2012). However, unit options only become exercisable at certain times (typically February, May, August and November) during the calendar year following the year in which they vest.

The fair value of each unit option is estimated on the date of grant using the Black-Scholes option pricing model, which incorporates various assumptions including expected life of the option, risk-free interest rates, expected distribution yield on our common units, and expected price volatility of our common units. In general, our assumption of expected life of the options represents the period of time that the options are expected to be outstanding based on an analysis of our historical option activity. Our selection of the risk-free interest rate is based on published yields for U.S. government securities with comparable terms. The expected distribution yield and unit price volatility is estimated based on several factors, which include an analysis of historical price volatility and distribution yield over a period equal to the expected life of the option.

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Equity Awards Outstanding at December 31, 2011

The following information summarizes each named executive officer’s long-term incentive awards outstanding at December 31, 2011. We expect to be allocated our pro rata share of the grant date fair value associated with such awards under the ASA. As a result, the gross market values listed in the following table for restricted common unit awards do not represent the amount of expense we expect to recognize in connection with such awards.

	Option Awards			Unit Awards	
	Number of Units Underlying	Number of Units Underlying	Option	Number of Units	Market Value of Units