ENTERPRISE PRODUCTS PARTNERS L P
Form 10-K
March 01, 2010

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, 2009

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

| | |
|---|---|
| 1100 Louisiana Street, 10th Floor, Houston, Texas | 77002 |
| (Address of Principal Executive Offices) | (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 (or "EPD's") common units held by non-affiliates at June 30, 2009 was approximately $7.51 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, including Dan L. Duncan. There were 618,813,932 common units of EPD (including 2,684,614 restricted common units) and 4,520,431 Class B units (which generally vote together with the common units) outstanding at February 1, 2010.

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## SIGNIFICANT RELATIONSHIPS REFERENCED IN THIS ANNUAL REPORT

Unless the context requires otherwise, references to "we," "us," "our," or "Enterprise Products Partners" are 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 Products Partners through which Enterprise Products Partners conducts substantially all of its business, and its consolidated subsidiaries.

References to "EPGP" mean Enterprise Products GP, LLC, which is our general partner.

References to "Duncan Energy Partners" mean Duncan Energy Partners L.P., which is a consolidated subsidiary of EPO. Duncan Energy Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "DEP." References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

References to "Enterprise GP Holdings" mean Enterprise GP Holdings L.P., a publicly traded Delaware limited partnership, the units of which are listed on the NYSE under the ticker symbol "EPE." Enterprise GP Holdings owns EPGP. The general partner of Enterprise GP Holdings is EPE Holdings, LLC ("EPE Holdings"), a wholly owned subsidiary of Dan Duncan LLC, all of the membership interests of which are owned by Dan L. Duncan.

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 completed the mergers with TEPPCO and TEPPCO GP (such related mergers referred to herein individually and together as the "TEPPCO Merger").

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP"). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." ETP is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETP." The general partner of Energy Transfer Equity is LE GP, LLC ("LE GP").

References to "EPCO" mean Enterprise Products Company (formerly EPCO, Inc.) and its privately held affiliates. We, EPO, Duncan Energy Partners, DEP GP, EPGP, Enterprise GP Holdings and EPE Holdings are affiliates under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

References to "Employee Partnerships" mean EPE Unit L.P. ("EPE Unit I"), EPE Unit II, L.P. ("EPE Unit II"), EPE Unit III, L.P. ("EPE Unit III"), Enterprise Unit L.P. ("Enterprise Unit") and EPCO Unit L.P. ("EPCO Unit"), collectively, all of which are privately held affiliates of EPCO.

## CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This annual report on Form 10-K for the year ended December 31, 2009 ("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 such 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. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in 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

## Items 1 and 2. Business and Properties.

### General

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids ("NGLs"), crude oil, refined products and certain petrochemicals. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We conduct substantially all of our business through EPO. 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.epplp.com.

We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the NYSE under the ticker symbol "EPD." We are owned 98% by our limited partners and 2% by our general partner, EPGP. Our general partner is wholly owned by a publicly traded affiliate, Enterprise GP Holdings, the units of which are listed on the NYSE under the ticker symbol "EPE."

### Business Strategy

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

§ capitalize on expected development 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 Shale, Haynesville Shale, Eagle Ford Shale, Marcellus Shale and deepwater Gulf of Mexico producing regions;

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

§ 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; and

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

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. For information regarding our growth capital projects, see "Liquidity and Capital Resources – Capital Spending" included under Item 7 of this annual report.

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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.

Significant Recent Developments

On October 26, 2009, the related mergers of our wholly owned subsidiaries with TEPPCO and TEPPCO GP were completed (collectively, we refer to these transactions as the "TEPPCO Merger"). Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of ours, and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, were entitled to receive 1.24 of our common units for each TEPPCO unit. In total, we issued an aggregate of 126,932,318 common units and 4,520,431 Class B units in connection with the TEPPCO Merger as consideration for both the TEPPCO units and TEPPCO GP membership interests. TEPPCO's units, which had been trading on the NYSE under the ticker symbol "TPP," have been delisted and are no longer publicly traded. On October 27, 2009, our TEPPCO and TEPPCO GP equity interests were contributed to EPO, and TEPPCO and TEPPCO GP became wholly owned subsidiaries of EPO.

For additional information regarding the TEPPCO Merger and other developments during 2009, see "Significant Recent Developments" included under Item 7 of this annual report, which is incorporated by reference into this Item 1 and 2 discussion.

Basis of Presentation

See Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the basis for presentation of our general purpose financial statements. Such information is incorporated by reference into this Item 1 and 2 discussion.

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 United States, Canada and the Gulf of Mexico with domestic consumers and international markets. We have five reportable business segments:

§ NGL Pipelines & Services;

§ Onshore Natural Gas Pipelines & Services;

§ Onshore Crude Oil Pipelines & Services;

§ Offshore Pipelines & Services; and

§ Petrochemical & Refined Products Services.

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

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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. During 2009, our largest non-affiliated customer based on revenues was Shell Oil Company and its affiliates ("Shell"), which accounted for 9.8% of our revenues. During 2008 and 2007, our largest non-affiliated customer based on revenues was Valero Energy Corporation and its affiliates ("Valero"), which accounted for 11.2% and 8.9%, respectively, of our revenues.

As generally used in the energy industry and in this document, the identified terms have the following meanings:

| | |
|---|---|
| /d | = per day |
| BBtus | = billion British thermal units |
| Bcf | = billion cubic feet |
| Lbs | = pounds |
| MBPD | = thousand barrels per day |
| MBbls | = thousand barrels |
| MMBbls | = million barrels |
| MMBtus | = million British thermal units |
| MMcf | = million cubic feet |

For information regarding our results of operations, including significant measures of historical throughput, production and processing rates, 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.

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 16,300 miles; (iii) NGL and related product storage and terminal facilities with 163.4 MMBbls of working storage capacity and (iv) NGL fractionation facilities. 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.

Natural gas processing and related NGL marketing activities. At the core of our natural gas processing business are 25 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 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

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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.

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 percent-of-liquids contracts, percent-of-proceeds contracts, fee-based contracts, hybrid contracts (a combination of percent-of-liquids and fee-based contract terms), keepwhole contracts and margin-band contracts.  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 on NGL marketing sales contracts.  In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we extract and sell 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.  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.  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.  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 gas processing 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.

Our NGL marketing activities generate revenues from the sale and delivery of NGLs obtained through our processing activities and spot and contract purchases from third parties.  These 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.

Our NGL marketing activities include production and purchases of inventories of mixed NGLs and purity NGL products. As a result of exceptional energy market conditions during 2009, we significantly increased our physical NGL inventory purchases and related forward physical sales commitments. In general, the significant increase in volumes dedicated to forward physical sales contracts improves the overall utilization and profitability of our fee-based assets. Our inventories of ethane, propane and normal butane 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. Isobutane and natural gasoline inventories are generally stable and less cyclical throughout the year. Generally, our inventory cycle begins in late-February to mid-March (the seasonal low point), building through September, and remaining level until early December before being drawn down through winter until the seasonal low is reached again.

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 facilities and import/export terminals. 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, petrochemical plants 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). The transportation fees charged under these arrangements 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, purity NGL products and petrochemical 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 rate (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. The 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 charge other 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 throughput 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. 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 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 11 NGL fractionation facilities located in Texas, Louisiana, Colorado and Ohio. NGL fractionation facilities separate mixed NGL streams into purity NGL products. The primary sources of mixed NGLs fractionated in the United States are domestic natural gas processing plants and 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.

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 by our NGL fractionation facilities 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. These fees (usually stated in cents per gallon) are contractually subject to adjustment for changes in certain fractionation expenses, including 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. 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 United States 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 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 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 significant natural gas processing assets included in our NGL Pipelines & Services business segment at February 1, 2010.

| 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 (2) | Colorado | 100% | 1.70 | 1.70 |
| Pioneer | Wyoming | 100% | 1.35 | 1.35 |
| Toca | Louisiana | 67.4% | 0.70 | 1.10 |
| Chaco | New Mexico | 100% | 0.65 | 0.65 |
| North Terrebonne | Louisiana | 56.4% | 0.73 | 1.30 |
| Calumet | Louisiana | 35.4% | 0.57 | 1.60 |
| Neptune | Louisiana | 66% | 0.43 | 0.65 |
| Pascagoula | Mississippi | 40% | 0.40 | 1.50 |
| Yscloskey | Louisiana | 13.9% | 0.26 | 1.85 |
| Thompsonville | Texas | 100% | 0.33 | 0.33 |
| Shoup | Texas | 100% | 0.29 | 0.29 |
| Gilmore | Texas | 100% | 0.25 | 0.25 |
| Armstrong | Texas | 100% | 0.25 | 0.25 |
| Others (11 facilities) (3) | Texas, New Mexico, Louisiana | Various (4) | 1.27 | 2.93 |
| Total processing capacities | | | 9.18 | 15.75 |

(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 commenced natural gas processing operations at our Meeker facility in October 2007 and subsequently began the Meeker Phase II expansion project to double the natural gas processing capacity to 1.7 Bcf/d at this facility. The Meeker Phase II expansion became operational during March 2009.
(3) Other natural gas processing facilities include our Venice, Sea Robin and Burns Point facilities located in Louisiana; Indian Basin, Carlsbad and Chaparral facilities located in New Mexico; and San Martin, Delmita, Sonora, Shilling and Indian Springs facilities located in Texas. Our ownership in the Venice plant is through our 13.1% equity method investment in Venice Energy Services Company, L.L.C. ("VESCO").
(4) Our ownership in these facilities ranges from 13.1% to 100%.

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, Calumet, Neptune, Burns Point, Carlsbad and Chaparral plants and all of the Texas facilities. On a weighted-average basis, utilization rates for these assets were 48.3%, 52.4% and 51.5% during the years ended December 31, 2009, 2008 and 2007, respectively. These rates reflect the periods in which we owned an interest in such facilities.

Our NGL marketing activities utilize a fleet of approximately 600 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 United States and parts of Canada. We have rail loading and unloading 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, 2010.

| Description of Asset | Location(s) | Our Ownership Interest | Length (Miles) | Useable Storage Capacity (MMBbls) |
|---|---|---|---|---|
| NGL pipelines: | | | | |
| Mid-America Pipeline System | Midwest and Western U.S. | 100% | 7,832 | |
| Seminole Pipeline | Texas | 90% (1) | 1,346 | |
| South Texas NGL System | Texas | 100% (2) | 1,317 | |
| Dixie Pipeline | South and Southeastern U.S. | 100% | 1,306 | |
| Chaparral NGL System (3) | Texas, New Mexico | 100% | 1,010 | |
| Louisiana Pipeline System | Louisiana | Various (4) | 827 | |
| Skelly-Belvieu Pipeline | Texas | 50% (5) | 572 | |
| Promix NGL Gathering System | Louisiana | 50% (6) | 364 | |
| Houston Ship Channel | Texas | 100% | 254 | |
| Rio Grande Pipeline | Texas | 70% (7) | 249 | |
| Lou-Tex NGL Pipeline | Texas, Louisiana | 100% | 205 | |
| Others (11 systems) (8) | Various | Various | 1,013 | |
| Total miles | | | 16,295 | |
| NGL and related product storage capacity by state: | | | | |
| Texas (9) | | | | 124.4 |
| Louisiana | | | | 15.2 |
| Kansas | | | | 8.4 |
| Mississippi | | | | 5.8 |
| Others (10) | | | | 9.6 |
| Total working capacity (11) | | | | 163.4 |

(1) We hold a 90% interest in this system through a majority owned subsidiary, Seminole Pipeline Company (“Seminole”).
(2) The ownership interest presented reflects consolidated ownership of these systems by EPO (34%) and Duncan Energy Partners (66%).
(3) The Chaparral NGL System includes the 180-mile Quanah Pipeline, which begins in Sutton County, Texas, and connects to the Chaparral Pipeline near Midland, Texas.
(4) Of the 827 total miles for this system, we own 100% of 774 miles and 52.5% of the remaining 53 miles.
(5) Our ownership interest in this pipeline is held indirectly through our equity method investment in Skelly-Belvieu Pipeline Company, L.L.C. (“Skelly-Belvieu”).
(6) Our ownership interest in this pipeline system is held indirectly through our equity method investment in K/D/S Promix, L.L.C. (“Promix”).
(7) We hold a 70% interest in this system through a majority owned subsidiary, Rio Grande Pipeline Company (“Rio Grande”). We acquired our ownership interest in Rio Grande in December 2009.
(8) Includes our Tri-States, Belle Rose, Wilprise, Chunchula, Bay Area and South Dean pipelines located in the coastal regions of Alabama, Louisiana, Mississippi and Texas; Port Arthur, Wilcox, Panola and San Jacinto pipelines located in east Texas; and our Meeker pipeline in Colorado.

(9) The amount shown for Texas includes 34 underground NGL and petrochemical storage caverns with an aggregate working capacity of approximately 100 MMBbls that are owned by EPO (34%) and Duncan Energy Partners (66%). These 34 caverns are located in Mont Belvieu, Texas.
(10) 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, South Dakota and Wisconsin.
(11) Our underground storage caverns and above ground storage tanks have an aggregate 163.4 MMBbls of total working storage capacity, which includes 23.4 MMBbls held under long-term operating leases. The leased facilities are located in Indiana, Kansas, Louisiana, South Dakota and Texas.

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 2,099 MBPD, 1,948 MBPD and 1,794 MBPD during the years ended December 31, 2009, 2008 and 2007, 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 Skelly-Belvieu Pipeline, Tri-States and a small portion of the Louisiana Pipeline System.

§ The Mid-America Pipeline System is a regulated NGL pipeline system consisting of three primary segments: the 2,793-mile Rocky Mountain pipeline, the 2,773-mile Conway North pipeline and the 2,266-mile Conway South pipeline. This system is present in 13 states: Wyoming, Utah, Colorado, New Mexico, Texas, Oklahoma, Kansas, Missouri, Nebraska, Iowa, Illinois, Minnesota and Wisconsin. 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. The Conway South pipeline connects the Conway hub with Kansas refineries and transports NGLs to and from Conway, Kansas to the Hobbs hub. The Mid-America Pipeline System interconnects with our Seminole Pipeline and Hobbs NGL fractionator and storage facility at the Hobbs hub. This system includes 15 unregulated propane terminals.

During 2009, approximately 50% 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.

§ 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 fractionator 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 fractionation facilities. In turn, the system transports NGLs from our south Texas NGL fractionation facilities 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 Dixie Pipeline is a regulated pipeline that extends from southeast Texas and Louisiana to markets in the southeastern United States 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.

§ 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 830-mile regulated Chaparral pipeline and the 180-mile unregulated Quanah pipeline.

§ The Louisiana Pipeline System is a network of NGL pipelines located in south Louisiana. This system transports NGLs originating in Louisiana and Texas to refineries and petrochemical companies located along the Mississippi River corridor in south Louisiana. This system also provides transportation services for our natural gas processing plants, NGL fractionators and other assets located in Louisiana. In December 2009, we acquired 215 miles of intrastate pipelines from Chevron Midstream Pipelines LLC that expand and extend our Louisiana Pipeline System. Originating from a central point in Henry, Louisiana, the acquired pipelines extend westward to Lake Charles, northward to an interconnect with the Dixie Pipeline at Breaux Bridge, and eastward to Napoleonville, Louisiana, where our Promix NGL fractionation and storage facilities are located.

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§ The Skelly-Belvieu Pipeline is a regulated pipeline that transports mixed NGLs from Skellytown, Texas to Mont Belvieu, Texas. We anticipate becoming operator of this pipeline by January 1, 2011.

§ The Promix NGL Gathering System gathers mixed NGLs from natural gas processing plants in south 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.

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 that are operated for us by a third-party.

Our largest underground storage facility is located in Mont Belvieu, Texas and is owned 66% by Duncan Energy Partners and 34% by EPO. This storage facility consists of 34 underground NGL and petrochemical salt dome storage caverns with an aggregate working 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.

The following table summarizes the significant NGL fractionation assets included in our NGL Pipelines & Services business segment at February 1, 2010.

| Description of Asset | Location | Our Ownership Interest | Net Plant Capacity (MBPD) (1) | Total Plant Capacity (MBPD) |
|---|---|---|---|---|
| NGL fractionation facilities: | | | | |
| Mont Belvieu | Texas | 75% (2) | 178 | 230 |
| Shoup and Armstrong | Texas | 100% (3) | 82 | 82 |
| Hobbs | Texas | 100% | 75 | 75 |
| Norco | Louisiana | 100% | 75 | 75 |
| Promix | Louisiana | 50% (4) | 73 | 145 |
| BRF | Louisiana | 32.2% (5) | 19 | 60 |
| Tebone | Louisiana | 56.4% (2) | 12 | 30 |
| Other (6) | Colorado, Ohio | 100% | 15 | 15 |
| Total plant capacities | | | 529 | 712 |

(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) Ownership interests presented reflect direct consolidated interests in each facility.
(3) The ownership interest presented reflects consolidated ownership of these plants by EPO (34%) and Duncan Energy Partners (66%).
(4) Our ownership interest in this facility is held indirectly through our equity method investment in Promix.
(5) Our ownership interest in this facility is held indirectly through our equity method investment in Baton Rouge Fractionators LLC ("BRF").
(6) Consists of two NGL fractionation facilities located in northeast Colorado and a fractionation facility located near Todhunter, Ohio.

The following information highlights the general use of each of our principal NGL fractionation facilities. We operate all of our NGL fractionation facilities, with the exception of our two Colorado 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 August 2009, we announced plans to build a new 75 MBPD NGL fractionator at our Mont Belvieu facility that will provide us with additional capacity to process growing NGL volumes from producing areas in the Rockies, the Barnett Shale and the emerging Eagle Ford Shale supply basin in south Texas. This growth capital project will increase our gross NGL fractionation capacity at Mont Belvieu to approximately 305 MBPD. The project is expected to be completed in the first quarter of 2011.

§ 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 Pipeline System.

§ Our Hobbs NGL fractionation facility is located in Gaines County, Texas, where it serves petrochemical plants and refineries in west Texas, New Mexico, California and northern Mexico. The Hobbs facility 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.

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

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

§ The BRF facility fractionates mixed NGLs from natural gas processing plants located in Alabama, Mississippi and south Louisiana.

On a weighted-average basis, utilization rates for our NGL fractionators were 88.8%, 83.6% and 78% during the years ended December 31, 2009, 2008 and 2007, respectively. These rates reflect the periods in which we owned an interest in such facilities.

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 20,000 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 up to 11,800 barrels per hour. Our average combined NGL import and

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export volumes were 98 MBPD, 74 MBPD and 84 MBPD for the years ended December 31, 2009, 2008 and 2007, respectively.

Onshore Natural Gas Pipelines & Services

Our Onshore Natural Gas Pipelines & Services business segment includes approximately 19,200 miles of onshore natural gas pipeline systems that provide for the gathering and transportation of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. We own two salt dome natural gas storage facilities located in Mississippi and lease natural gas storage facilities located in Texas and Louisiana. This segment also includes our related natural gas marketing activities.

Onshore natural gas pipelines and related natural gas marketing activities. Our onshore natural gas pipeline systems 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 and Eagle Ford supply basins in the western United States. 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 through system interconnects and redeliver the natural gas to processing facilities, local gas distribution companies, industrial or municipal customers, or to other onshore pipelines.

Our onshore natural gas pipelines typically generate revenues from transportation agreements whereby 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 reserved in our pipelines whether or not the shipper actually utilizes such capacity. 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. We entered the natural gas marketing business in an effort to maximize the utilization of our portfolio of natural gas pipeline and storage assets. We expect our natural gas marketing business to continue to expand in the future. The results of operations for our onshore natural gas pipelines and related marketing activities are generally dependent upon the volume of natural gas transported and/or sold 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.

Underground natural gas storage. We own two underground salt dome natural gas storage facilities located near Hattiesburg, Mississippi that serve the domestic Northeast, Mid-Atlantic and Southeast natural gas markets. On a combined basis, these facilities (our Petal Gas Storage ("Petal") and

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Hattiesburg Gas Storage locations) are capable of delivering in excess of 1.4 Bcf/d of natural gas into six interstate pipeline systems. We also lease underground salt dome natural gas storage caverns that serve markets in Texas and Louisiana.

Our natural gas storage facilities are designed for sustained periods of high natural gas deliveries, including the ability to quickly switch from full injection to full withdrawal modes of operation. The ability of underground salt dome storage caverns to handle high levels of injections and withdrawals of natural gas benefits customers who desire the ability to meet load swings and to cover major supply interruption events, such as hurricanes and temporary losses of production. High injection and withdrawal rates also allow customers to take advantage of periods of volatile natural gas prices and respond quickly in situations where they have natural gas imbalance issues on pipelines connected to the storage facilities.

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.

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. Likewise, this seasonality also impacts the timing of injections and withdrawals at our natural gas storage facilities.

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. Competition for natural gas storage is primarily based on location and the ability to deliver natural gas in a timely and reliable manner. Our natural gas storage facilities compete with other providers of natural gas storage, including other salt dome storage facilities and depleted reservoir facilities. 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 other 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, 2010.

| Description of Asset | Location(s) | Our Ownership Interest | Length (Miles) | Approx. Net Capacity, Natural Gas (MMcf/d) | Gross Capacity (Bcf) |
|---|---|---|---|---|---|
| Onshore natural gas pipelines: | | | | | |
| Texas Intrastate System | Texas | 100% (1) | 8,051 | 6,640 | |
| Jonah Gathering System | Wyoming | 100% | 849 | 2,550 | |
| Piceance Basin Gathering System | Colorado | 100% | 102 | 1,600 | |
| White River Hub | Colorado | 50% | 10 | 1,500 | |
| San Juan Gathering System | New Mexico, Colorado | 100% | 6,070 | 1,200 | |
| Acadian Gas System | Louisiana | Various (2) | 1,041 | 1,149 | |
| Val Verde Gas Gathering System | New Mexico, Colorado | 100% | 420 | 550 | |
| Carlsbad Gathering System | Texas, New Mexico | 100% | 919 | 220 | |
| Alabama Intrastate System | Alabama | 100% | 408 | 200 | |
| Encinal Gathering System | Texas | 100% | 535 | 143 | |
| Other (6 systems) (3) | Texas, Mississippi | Various (4) | 785 | 1,840 | |
| Total miles | | | 19,190 | | |
| Natural gas storage facilities: | | | | | |
| Petal | Mississippi | 100% | | | 16.6 |
| Hattiesburg | Mississippi | 100% | | | 2.1 |
| Wilson | Texas | Leased (5) | | | 6.8 |
| Acadian | Louisiana | Leased (6) | | | 1.3 |
| Total gross capacity | | | | | 26.8 |

(1) In general, our consolidated ownership of this system is 100% through interests held by EPO and Duncan Energy Partners. We own and operate a 50% undivided interest in the 641-mile Channel pipeline system, which is a component of the Texas Intrastate System. The remaining 50% is owned by affiliates of Energy Transfer Equity. In addition, we own less than a 100% undivided interest in and lease certain segments of the Enterprise Texas pipeline system, which is a component of the Texas Intrastate System.
(2) Our ownership interest reflects consolidated ownership of Acadian Gas by EPO (34%) and Duncan Energy Partners (66%). Amounts presented include the 49.5% equity method investment that Acadian Gas has in the 27-mile Evangeline pipeline.
(3) Includes the Delmita, Big Thicket, Indian Springs and Canales gathering systems located in Texas and the Petal and Hattiesburg pipelines located in Mississippi. The Delmita and Big Thicket gathering systems are integral parts of our natural gas processing operations, the results of operations and assets of which are accounted for under our NGL Pipelines & Services business segment. The Petal and Hattiesburg pipelines, which have a combined capacity in excess of 1.4 MMcf/d, are integral components of our Petal and Hattiesburg natural gas storage operations.
(4) We own 100% of these assets with the exception of the Indian Springs system, in which we own an 80% undivided interest through a consolidated subsidiary. Our 100% ownership interest in Big Thicket reflects consolidated ownership by EPO (34%) and Duncan Energy Partners (66%).
(5) We hold this facility under an operating lease that expires in January 2028.

(6) We hold this facility under an operating lease that expires in December 2012.

On a weighted-average basis, aggregate utilization rates for our onshore natural gas pipelines were approximately 64.4%, 68.7% and 67.0% during the years ended December 31, 2009, 2008 and 2007, respectively. The utilization rate for 2008 excludes the White River Hub, which commenced operations during December 2008. The utilization rate for 2007 excludes our Piceance Basin Gathering System, which operated at an average utilization rate of 24.3% during 2007 as volumes ramped-up on this system. 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 and transports natural gas from supply basins in Texas (from both onshore and offshore sources) 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 6,560-mile Enterprise Texas pipeline system, the 641-mile Channel pipeline system, the 660-mile Waha gathering system and the 190-mile TPC Offshore gathering system. The Enterprise Texas pipeline system includes a 263-mile

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pipeline we lease from an affiliate of ETP. The leased 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 Texas Intrastate System, was completed in late February 2009 and is capable of transporting up to 1.2 Bcf/d of natural gas from the prolific Barnett Shale production 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 late 2008, we began design of the 40-mile Trinity River Lateral, which is expected to be completed during the second quarter of 2010. The Trinity River Lateral will be capable of transporting up to 1.0 Bcf/d of natural gas and will provide producers in the Barnett Shale production basin with additional takeaway capacity. We are also constructing a new storage cavern adjacent to the leased Wilson natural gas storage facility that is expected to be completed in 2010. When completed, this new cavern is expected to provide us with an additional 5.0 Bcf of natural gas storage capacity.

§ 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 basins for delivery to regional natural gas processing plants, including our Pioneer facility, and major interstate pipelines. In mid-2009, we completed an expansion of that portion of the system that serves the Pinedale field, which increased total capacity of the Jonah Gathering System from 2.35 Bcf/d to 2.55 Bcf/d.

§ The Piceance Basin Gathering System consists of the 48-mile Piceance Creek, 32-mile Great Divide and 22-mile Collbran Valley gathering systems located in the Piceance Basin of northwestern Colorado. The Piceance Creek gathering system extends from a connection with the Great Divide gathering system to our Meeker natural gas processing plant. The Great Divide gathering system gathers natural gas from the southern portion of the Piceance Basin, including natural gas gathered on the Collbran Valley gathering system, to an interconnect with our Piceance Creek gathering system.

§ 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). White River Hub began service in December 2008.

§ The San Juan Gathering System serves producers in the San Juan Basin of north New Mexico and south Colorado. This system gathers natural gas from production wells located in the San Juan Basin and delivers the natural gas to regional processing facilities, including our Chaco natural gas processing plant located in New Mexico.

§ The Acadian Gas System purchases, transports, stores and resells natural gas in south Louisiana. The Acadian Gas System is comprised of the 576-mile Cypress pipeline, the 438-mile Acadian pipeline and the 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.

In October 2009, we and Duncan Energy Partners announced plans to extend our Acadian Gas System into the rapidly growing Haynesville Shale supply basin in northwest Louisiana. Our 249-mile Haynesville Extension pipeline will have transportation capacity of up to 2.1 Bcf/d of natural gas and will extend from the Haynesville region to interconnects with interstate pipelines in central Louisiana and with our existing Acadian Gas System. The pipeline is expected to be placed into service during the third quarter of 2011.

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The Haynesville Extension will provide producers in the Haynesville Shale supply basin with takeaway capacity, including access to more than 150 end-use markets along the Mississippi River corridor between Baton Rouge and New Orleans, Louisiana. In addition, shippers will be able to access our Napoleonville salt dome storage cavern and have the ability to make physical deliveries into the Henry Hub and benefit from more favorable pricing points. The Haynesville Extension will also allow shippers to reach nine interstate pipeline systems.

§ The Val Verde Gas Gathering System gathers natural gas, including coal bed methane from the Fruitland Coal Formation in the San Juan Basin, from producing regions in north New Mexico and south Colorado.

§ The Carlsbad Gathering System gathers natural gas from the Permian Basin region of Texas and New Mexico for delivery into the El Paso Natural Gas, Transwestern and Oasis pipelines.

§ The Alabama Intrastate System gathers natural gas, primarily coal bed methane, from the Black Warrior supply basin in Alabama. This system is also involved in the purchase, transportation and sale of natural gas.

§ The Encinal Gathering System gathers natural gas from the Olmos, Wilcox and Eagle Ford formations in south Texas for processing at our south Texas natural gas processing plants.

Onshore Crude Oil Pipelines & Services

Our Onshore Crude Oil Pipelines & Services business segment includes approximately 4,400 miles of onshore crude oil pipelines and 10.5 MMBbls of above-ground storage tank capacity. This segment 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 Oklahoma, New Mexico 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 rate. 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. To limit the exposure of 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.

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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.

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. Declines in domestic crude oil production have intensified this competition. 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, 2010.

| Description of Asset | Location(s) | Our Ownership Interest | Length (Miles) | Useable Storage Capacity (MMBbls) (1) |
|---|---|---|---|---|
| Crude oil pipelines: | | | | |
| Seaway Crude Pipeline System | Texas, Oklahoma | 50% (2) | 530 | 3.4 |
| Red River System | Texas, Oklahoma | 100% | 1,690 | 1.2 |
| South Texas System | Texas | 100% | 1,150 | 1.1 |
| West Texas System | Texas, New Mexico | 100% | 360 | 0.4 |
| Other (4 systems) (3) | Texas, Oklahoma, New Mexico | Various | 681 | 0.3 |
| Total miles | | | 4,411 | |
| | | | | |
| Crude oil terminals: | | | | |
| Cushing terminal | Oklahoma | 100% | | 3.1 |
| Midland terminal | Texas | 100% | | 1.0 |
| Total capacity | | | | 10.5 |

(1) Useable storage capacity is presented net to our ownership interest in each asset.
(2) Our ownership interest in this pipeline system is held indirectly through our equity method investment in Seaway Crude Pipeline Company ("Seaway").
(3) Includes our Azelea, Mesquite and Sharon Ridge crude oil gathering systems and Basin Pipeline System. We own 100% of these assets with the exception of the Basin Pipeline System, in which we own a 13% undivided interest.

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 680 MBPD, 696 MBPD and 652 MBPD during the years ended December 31, 2009, 2008 and 2007, respectively.

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 transports imported crude oil from Freeport, Texas to Cushing, Oklahoma and supplies refineries in the Houston, Texas area through its terminal facility at Texas City, Texas. The Seaway Crude Pipeline System also has a connection to our South Texas System that allows it to receive both onshore and offshore domestic crude oil production from the Texas Gulf Coast area for delivery to Cushing.

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

§ The South Texas System transports crude oil from an origination point in south Texas to the Houston, Texas area. Crude oil transported on the South Texas System is delivered either to Houston area refineries or pipeline interconnects (including those with our Seaway Crude Pipeline System) for ultimate delivery to Cushing, Oklahoma.

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

§ 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 1.0 MMBbls through the use of 12 above-ground storage tanks.

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 1,400 miles of offshore natural gas pipelines, approximately 1,000 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, revenues from our offshore pipelines are 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. In the case of our Poseidon Oil Pipeline System, we purchase crude oil from producers and shippers at a receipt point (at a fixed or index-based price less a location differential) and then sell like quantities of crude oil back to the customer at onshore Louisiana locations (at the same fixed or index-based price, as applicable). The net revenue we recognize from such arrangements is based on the location differential, which represents the fee Poseidon charges for providing transportation services.

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 grid; provide an efficient means to perform pipeline maintenance; locate compression, separation and production handling equipment and similar assets; conduct drilling operations during the initial development phase of an oil and natural gas property and process off-lease production. 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. Revenues from commodity charges are 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 utilizing our Independence Hub platform have agreed to pay us $54.6 million of demand fees annually through March 2012. These demand fees are in addition to commodity charges they pay us based on volumes delivered to the platform.

In August 2008, we and Oiltanking Holding Americas, Inc. (“Oiltanking”) announced the formation of a joint venture, the Texas Offshore Port System (“TOPS”), that would design, construct, operate and own a Texas offshore crude oil port and related onshore pipeline and storage system located

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along the upper Texas Gulf Coast. In April 2009, we dissociated from TOPS. As a result, operating costs and expenses for 2009 includes a non-cash charge of $68.4 million. This loss represents the forfeiture of our cumulative investment in TOPS through the date of dissociation. Furthermore, in September 2009, we and Oiltanking entered into a settlement agreement that resolved all disputes between the parties related to the business and affairs of the TOPS project. We recognized an additional $66.9 million of operating costs and expenses during 2009 in connection with this settlement. The aggregate $135.3 million of charges recorded during 2009 were classified within the Offshore Pipelines & Services business segment.

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. 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.

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Properties. The following table summarizes the significant assets included in our Offshore Pipelines & Services business segment at February 1, 2010.

| 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: | | | | | |
| High Island Offshore System (1) | 100% | 291 | | 1,800 | |
| Viosca Knoll Gathering System | 100% | 137 | | 1,000 | |
| Independence Trail | 100% | 134 | | 1,000 | |
| Green Canyon Laterals | Various (2) | 78 | | 605 | |
| Phoenix Gathering System | 100% | 77 | | 450 | |
| Falcon Natural Gas Pipeline | 100% | 14 | | 400 | |
| Anaconda Gathering System | 100% | 137 | | 300 | |
| Manta Ray Offshore Gathering System (3) | 25.7% | 250 | | 206 | |
| Nautilus System (3) | 25.7% | 101 | | 154 | |
| Nemo Gathering System (5) | 33.9% | 24 | | 102 | |
| VESCO Gathering System (4) | 13.1% | 158 | | 65 | |
| Total miles | | 1,401 | | | |
| Offshore crude oil pipelines: | | | | | |
| Cameron Highway Oil Pipeline (6) | 50% | 374 | | | 250 |
| Poseidon Oil Pipeline System (7) | 36% | 367 | | | 144 |
| Shenzi Oil Pipeline | 100% | 83 | | | 230 |
| Allegheny Oil Pipeline | 100% | 43 | | | 140 |
| Marco Polo Oil Pipeline | 100% | 37 | | | 120 |
| Constitution Oil Pipeline | 100% | 67 | | | 80 |
| Typhoon Oil Pipeline | 100% | 17 | | | 80 |
| Tarantula Oil Pipeline | 100% | 4 | | | 30 |
| Total miles | | 992 | | | |
| Offshore hub platforms: | | | | | |
| Independence Hub | 80% | | 8,000 | 800 | N/A |
| Marco Polo (8) | 50% | | 4,300 | 150 | 60 |
| Viosca Knoll 817 | 100% | | 671 | 145 | 5 |
| Garden Banks 72 | 50% | | 518 | 113 | 18 |
| East Cameron 373 | 100% | | 441 | 195 | 3 |
| Falcon Nest | 100% | | 389 | 400 | 3 |

(1) Based on the maximum allowable operating pressure, our HIOS pipeline system can transport up to 1,800 MMcf/d of natural gas. On January 12, 2010, we filed for FERC authority to reduce the firm certificated capacity on the HIOS pipeline system from 1,400 MMcf/d to 350 MMcf/d.
(2) Our ownership interests in the Green Canyon Laterals ranges from 2.7% to 100%.
(3) Our ownership interest in these pipeline systems is held indirectly through our equity method investment in Neptune Pipeline Company, L.L.C. (“Neptune”).
(4) Our ownership interest in this system is held indirectly through our equity method investment in VESCO.
(5) Our ownership interest in this system is held indirectly through our equity method investment in Nemo Gathering Company, LLC (“Nemo”).

(6) Our 50% joint control ownership interest in this pipeline is held indirectly through our equity method investment in Cameron Highway Oil Pipeline Company ("Cameron Highway").
(7) Our ownership interest in this system is held indirectly through our equity method investment in Poseidon Oil Pipeline Company, LLC. ("Poseidon").
(8) Our 50% joint control ownership interest in this platform is held indirectly through our equity method investment in Deepwater Gateway, L.L.C. ("Deepwater Gateway").

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 22.3%, 22% and 24.1% during the years ended December 31, 2009, 2008 and 2007, respectively. For recently constructed assets, utilization rates reflect the periods since such assets were placed into service.

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The following information highlights the general use of each of our principal Gulf of Mexico offshore natural gas 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, Tennessee Gas Pipeline and the U-T Offshore System. The HIOS pipeline system includes eight pipeline junction and service platforms. In addition, this system includes the 86-mile East Breaks System that connects HIOS to the Hoover-Diana deepwater platform located in Alaminos Canyon Block 25.

§ 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 Tennessee Gas, Columbia Gulf, Southern Natural, Transco, Dauphin Island Gathering System and Destin Pipelines.

§ The Independence Trail natural gas pipeline transports natural gas from our Independence Hub platform to the Tennessee Gas Pipeline platform at West Delta 68. 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 Green Canyon Laterals consist of 13 pipeline laterals (which are extensions of natural gas pipelines) that transport natural gas to downstream pipelines, including HIOS.

§ The Phoenix Gathering System connects the Red Hawk platform located in the Garden Banks area of the Gulf of Mexico to the ANR pipeline system.

§ 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 Anaconda Gathering System connects our Marco Polo platform and the third-party owned Constitution platform to the ANR pipeline system.

§ 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 Manta Ray Offshore Gathering System to our Neptune natural gas processing plant located in south 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. This gathering pipeline is an integral part of the natural gas processing operations of VESCO and is accounted for under our NGL Pipelines & Services business segment.

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 28.7%, 20.1% and 19.3% during the years ended December 31, 2009, 2008 and 2007, respectively. For recently constructed assets, utilization rates reflect the periods since such assets were placed into service.

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§ 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 one pipeline junction platform.

§ 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 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 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 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.

With respect to natural gas processing capacity, the utilization rates (on a weighted-average basis) of our offshore platforms were approximately 39.4%, 36.5% and 28.6% during the years ended December 31, 2009, 2008 and 2007, respectively. With respect to crude oil processing capacity, the utilization rates (on a weighted-average basis) of our offshore platforms were approximately 13.6%, 16.9% and 26.1% during the years ended December 31, 2009, 2008 and 2007, 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.

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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 and related activities, (ii) butane isomerization facilities, (iii) an octane enhancement facility, (iv) refined products pipelines, including our Products Pipeline System (as defined below), and related activities and (v) marine transportation and other services.

Propylene fractionation and related activities. Our propylene fractionation and related activities primarily consist of two propylene fractionation plants (one located in Mont Belvieu, Texas and the other in Baton Rouge, Louisiana), propylene pipeline systems aggregating approximately 670 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 generate revenues from the purchase and fractionation of refinery grade propylene in the open market and the sale and delivery of products obtained through our propylene fractionation activities. 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.

As part of our petrochemical marketing activities, we have several long-term refinery grade 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 United States. 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 and alkylate for motor gasoline. The demand for commercial isomerization services depends upon the industry's requirements for high purity isobutane and isobutane in excess of naturally occurring isobutane produced from 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.

Octane enhancement. 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"). These products 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 the facility, it is 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. This facility undergoes an annual maintenance turnaround that generally occurs during the first quarter of each year. During these periods of shutdown, the plant may incur operating losses.

Refined products pipelines and related activities. Our refined products pipelines and related activities primarily consist of (i) a regulated 4,700-mile products pipeline system and related terminal operations (the "Products Pipeline System") that generally extends in a northeasterly direction from the upper Texas Gulf Coast to the northeast United States and (ii) a 50% joint venture interest in Centennial Pipeline LLC ("Centennial"), which owns a 794-mile refined products pipeline system that extends from the upper Texas Gulf Coast to central Illinois (the "Centennial Pipeline").

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 the distribution and marketing operations we provide at our Aberdeen, Mississippi and Boligee, Alabama river terminals. In the fourth quarter of 2009, we expanded the terminaling and marketing operations associated with our refined products pipeline business. These activities generated nominal amounts of gross operating margin during 2009; however, we expect that our refined products marketing activities will increase beginning in 2010 in an effort to increase the utilization of our portfolio of refined products pipelines and terminal assets.

The results of operations of our refined products pipelines are primarily dependent on the tariffs charged to customers to transport products. The tariffs charged for such services are either contractual or regulated by governmental agencies, including the FERC. 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.

Marine transportation and other services. Our marine transportation business consists of tow boats and tank barges that are used primarily to transport refined products, crude oil, asphalt, condensate, heavy fuel oil and other heated oil products along key inland and intercoastal U.S. waterways. Our marine transportation assets service refinery and storage terminal customers along the Mississippi, Illinois and Ohio rivers, the Intracoastal Waterway between Texas and Florida and the Tennessee-Tombigbee Waterway system. In addition, we provide marine vessel fueling services for cruise liners and cargo ships as well as other ship-assist services in Miami, Florida. Other non-marine services consist of the

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distribution of lubrication oils and specialty chemicals and the bulk transportation of fuels by truck, principally in Oklahoma, Texas, New Mexico and the Rocky Mountain region of the United States.

The results of operations of our marine transportation business, which we entered into in February 2008 upon the acquisition of tow boats, tank barges and related assets from Cenac Towing Co., Inc. and affiliates (collectively, "Cenac"), are generally dependent upon the level of fees charged to transport cargo. 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.

The results of operations from the distribution of lubrication oils and specialty chemicals and the bulk transportation of fuels are dependent on the sales price or transportation fees that we charge our customers.

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 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.

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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.

Properties. The following table summarizes the significant propylene fractionation, isomerization and octane enhancement production facilities and petrochemical pipelines included in our Petrochemical & Refined Products Services business segment at February 1, 2010, 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% (2) | 7 | 23 | |
| Total capacity | | | 80 | 110 | |
| Isomerization facility: | | | | | |
| Mont Belvieu (3) | Texas | 100% | 116 | 116 | |
| Petrochemical pipelines: | | | | | |
| Lou-Tex and Sabine Propylene | Texas, Louisiana | 100% (4) | | | 284 |
| North Dean Pipeline System | Texas | 100% | | | 138 |
| Texas City RGP Gathering System | Texas | 100% | | | 86 |
| Others (6 systems) (5) | Texas, Louisiana | Various (6) | | | 230 |
| Total miles | | | | | 738 |
| Octane enhancement production facilities: | | | | | |
| Mont Belvieu (7) | Texas | 100% | 12 | 12 | |

(1) We own a 66.7% interest in three of the units, which have an aggregate 41 MBPD of total plant capacity. In October 2009, we acquired the remaining 45.4% of one unit having 17 MBPD of plant capacity. We own 100% of the remaining two units.
(2) Our ownership interest in this 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 this facility were approximately 83.6%, 74.1% and 77.6% during the years ended December 31, 2009, 2008 and 2007, respectively.
(4) Reflects consolidated ownership of these pipelines by EPO (34%) and Duncan Energy Partners (66%).
(5) Includes our Texas City PGP Delivery System and Port Neches, La Porte, Port Arthur, Lake Charles and Bayport petrochemical pipelines.
(6) We own 100% of these pipelines with the exception of the 17-mile La Porte pipeline, in which we hold an aggregate 50% indirect interest through our equity method investments in La Porte Pipeline Company L.P. and La Porte Pipeline GP, L.L.C. In addition, we own a 50% undivided interest in the Lake Charles pipeline.
(7) On a weighted-average basis, utilization rates for this facility were approximately 50%, 58.3% and 58.3% during the years ended December 31, 2009, 2008 and 2007, respectively.

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 supply contracts. On a weighted-average basis, aggregate utilization rates of our propylene fractionation facilities were approximately 85%, 72.2% and 86% during the years ended December 31, 2009, 2008 and 2007, 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.

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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 124 MBPD, 116 MBPD and 114 MBPD during the years ended December 31, 2009, 2008 and 2007, 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, 2010.

| Description of Asset | Location(s) | Our Ownership Interest | Length (Miles) | Useable Storage Capacity (MMBbls) |
|---|---|---|---|---|
| Refined products pipelines and terminals: | | | | |
| Products Pipeline System (1) | Texas to Midwest and Northeast U.S. | 100% | 4,700 | 13.0 |
| Centennial Pipeline | Texas to central Illinois | 50% (2) | 794 | 2.3 |
| Other pipelines (3) | Texas | 100% | 210 | -- |
| River terminals (4) | Alabama, Mississippi | 100% | n/a | 0.6 |
| Total | | | 5,704 | 15.9 |

(1) In addition to the 13 MMBbls of refined products working storage capacity, we have 5.4 MMBbls of NGL working 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 this pipeline is held indirectly through our equity method investment in Centennial.
(3) Our Products Pipeline System includes 210 miles of unregulated pipelines in south Texas used primarily to transport petrochemical products.
(4) Represents product distribution and marketing terminals located in Aberdeen, Mississippi and Boligee, Alabama.

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. Total net throughput volumes for the Products Pipeline System were as follows for the periods presented:

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2009 | 2008 | 2007 |
| Refined products transportation (MBPD) | 459 | 492 | 542 |
| Petrochemical transportation (MBPD) | 118 | 104 | 111 |
| NGLs transportation (MBPD) | 105 | 106 | 115 |

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

§ The Products Pipeline System is a regulated pipeline system that transports refined products, petrochemicals and NGLs. This pipeline system includes receiving, storage and terminaling facilities and is present in 12 states: Texas, Louisiana, Arkansas, Tennessee, Missouri, Illinois, Kentucky, Indiana, Ohio, West Virginia, Pennsylvania and New

York. Our Products Pipeline System transports refined products from the upper Texas Gulf Coast, eastern Texas and southern Arkansas to the Central and Midwest regions of the United States with deliveries in Texas, Louisiana, Arkansas, Missouri, Illinois, Indiana, Ohio and Kentucky. At these points, refined products are delivered to terminals owned by us, connecting pipelines and customer-owned terminals. Petrochemicals are transported on our Products Pipeline System between Mont Belvieu, Texas and Port Arthur, Texas. Our Products Pipeline System transports NGLs from the upper Texas Gulf Coast to the Central, Midwest and Northeast regions of the United States and is

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the only pipeline that transports NGLs from the upper Texas Gulf Coast to the Northeast. The Centennial Pipeline effectively loops our Products Pipeline System between Beaumont, Texas and southern Illinois.

In December 2006, we signed an agreement with Motiva Enterprises, LLC ("Motiva") to construct and operate a refined products storage facility to support an expansion of Motiva's refinery in Port Arthur, Texas. Under the terms of the agreement, we will construct 20 storage tanks with a capacity of 5.4 MMBbls for gasoline and distillates, five 5-mile product pipelines connecting the storage facility to Motiva's refinery and distribution pipeline connections to the Colonial, Explorer and Magtex pipelines. As part of a separate but complementary initiative, we constructed an 11-mile pipeline to connect the new storage facility in Port Arthur to our refined products terminal in Beaumont, Texas.

§ 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 2.3 MMBbl refined products storage terminal located near Creal Springs, Illinois.

During 2009, we recognized a non-cash asset impairment charge of $17.6 million in connection with a reduction in future forecasted levels of throughput volumes at the Aberdeen and Boligee river terminals resulting from the suspension of three associated proposed river terminal construction projects. In addition, we accrued a liability of $28.7 million for pipeline deficiency fees we expect to pay a third-party in the future as a result of the reduced throughput volume forecast. For information regarding the asset impairment charge, see Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The following table summarizes the significant marine transportation assets included in our Petrochemical & Refined Products Services business segment at February 1, 2010.

| Class of Equipment | Number in Class | Capacity (bbl)/ Horsepower (hp) (as indicated by sign) |
|---|---|---|
| Inland marine transportation assets: | | |
| Barges | 32 | < 25,000 bbl |
| Barges | 96 | > 25,000 bbl |
| Tow boats | 32 | < 2,000 hp |
| Tow boats | 30 | =/> 2,000 hp |
| Offshore marine transportation assets: | | |
| Barges (includes three single-bottom barges) | 8 | > 20,000 bbl |
| Tow boats | 4 | < 2,000 hp |
| Tow boats | 3 | > 2,000 hp |

Our fleet of marine vessels operated at an average utilization rate of 87.5% and 93% during 2009 and 2008, 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. In June 2009, we expanded our marine transportation business with the acquisition of 19 tow boats and 28 tank barges from TransMontaigne Product Services Inc. for $50.0 million in cash. 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.

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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 fractionator is 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.

Capital Spending

For a discussion of our capital spending programs, see "Liquidity and Capital Resources" included under Item 7 of this annual report.

Regulation

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. Effective March 21, 2006, the FERC concluded that for the five-year period commencing July 1, 2006, liquids pipelines charging indexed rates may adjust their indexed ceilings annually by the PPI plus 1.3%. Prior to the end of that five year period, the FERC will once again review the PPI to determine whether it continues to measure adequately the cost changes in the liquids pipeline industry.

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

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System has been granted permission by the FERC to utilize Market-Based Rates for all of its refined products movements other than the Little Rock, Arkansas, and the Arcadia destination within the Shreveport-Arcadia, Louisiana destination markets, which are currently subject to the PPI.

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.

Mid-America Pipeline Company, LLC ("Mid-America") and Seminole are currently involved in a rate case before the FERC. The case primarily involves shipper protests of rate increases on Mid-America's Northern System 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 Seminole and Mid-America's Rocky Mountain System in FERC Docket Nos. OR06-5-000 and IS06-520-000. A hearing before an Administrative Law Judge began on October 2, 2007 and culminated with an initial decision on September 3, 2008. On October 23, 2009, the FERC approved an uncontested settlement agreement between Mid-America and the primary parties protesting the Northern System rates, which resolved all matters involving Mid-America's Northern System 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 the Northern System, which took effect January 1, 2010. Mid-America has also paid refunds to propane shippers, as provided by the settlement agreement.

The settlement agreement did not cover the challenges to the Seminole and Mid-America Rocky Mountain System rates at issue in Docket Nos. OR06-5-000 and IS06-520-000. On February 18, 2010, the FERC ruled on those issues, affirming the Initial Decision in all respects. 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. The FERC required Seminole and Mid-America to file revised rates in compliance with its order by March 22, 2010.

On November 5, 2009, Flint Hills Resources, LP ("Flint Hills") filed a complaint against Mid-America at the FERC in Docket No. OR10-2-000. The Flint Hills complaint challenges the rates for certain movements of butane, isobutane, natural gasoline, naphtha and refinery grade butane on Mid-America's Northern System. On February 2, 2010, the FERC issued an order establishing hearing procedures but holding them in abeyance subject to settlement discussions. We are unable to predict the outcome of this litigation.

The Lou-Tex Propylene 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.

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 and storage facilities 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

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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 includes: (i) certification, 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 employees function independently of marketing employees. 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 $1.0 million per day per violation.

In March 2009, we submitted to the FERC a general rate change application under Section 4 of the NGA proposing, among other things, an increase in the firm and interruptible transportation rates for High Island Offshore System, LLC. On April 23, 2009, the FERC issued an order accepting the rates subject to refund, conditions and the outcome of an evidentiary hearing. The rates went into effect subject to refund in October 2009. In February 2010, the FERC's Staff and the active intervenors reached an agreement in principle that, if filed as a formal settlement and approved by the FERC, will resolve all outstanding issues in the proceeding. Pending the FERC's action on the proposed settlement, the hearing procedures will be held in abeyance.

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, 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.

Natural Gas Pipelines. Our intrastate natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas. 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, 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.

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In September 2007, the FERC approved an uncontested settlement establishing our maximum firm and interruptible transportation rates for NGPA Section 311 service on the Enterprise Texas Pipeline. In June and July 2008, we filed to amend our Statement of Operating Conditions ("SOC") for our transportation and storage services, respectively. In September 2008, we submitted to the FERC a new proposed Section 311 rate for service on our Sherman Extension pipeline. On November 23, 2009, we filed an uncontested settlement agreement, which, if approved, would resolve the Sherman Extension rate issues. The other issues related to the SOC are reserved under the settlement agreement for a decision by the FERC based on the pleadings. Under the settlement agreement that resulted from the September 2007 proceeding, we are required to file another rate petition on or before April 2010 to justify our current rates or establish new rates for the NGPA Section 311 service on the remainder of the system. The FERC has not acted upon the settlement agreement. The Texas Railroad Commission has the authority to regulate the rates and terms of service for our intrastate transportation service in Texas.

In September 2007, the FERC also approved an uncontested settlement establishing our maximum firm and interruptible transportation rates for NGPA Section 311 service on the Enterprise Alabama Intrastate Pipeline. We are required to file another rate petition on or before May 2010 to justify our current rates or establish new rates for NGPA Section 311 service. The Alabama Public Service Commission has the authority to regulate the rates and terms of service for our intrastate transportation service in Alabama.

In July 2009, we filed with the FERC proposed changes to our SOC and to increase our interruptible transportation rates for NGPA Section 311 service for the Acadian and Cypress pipelines, which are part of our Acadian Gas System. On December 8, 2009, the FERC issued an order extending its review period to encourage settlement discussions. Settlement negotiations are on-going.

Sales of Natural Gas

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 are 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 new 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 certain non-interstate pipelines to post daily scheduled volume information and design capacity for certain points, and has also required the annual reporting of gas sales information, in order to increase transparency in natural gas markets. Non-interstate service providers, which include NGPA Section 311 service providers, are required to begin posting the information by June 30, 2010. 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.

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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 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. The Jones Act is a federal law that restricts maritime transportation between locations in the United States to vessels built and registered in the United States and owned and manned by United States citizens. As a result of our marine transportation business acquisition on February 1, 2008, we now engage in coastwise maritime transportation between locations in the United States, and as such, we are subject to the provisions of the Jones Act. As a result, we are responsible for monitoring the ownership of our subsidiary that engages in maritime transportation and for taking any remedial action necessary to insure that no violation of the Jones Act ownership restrictions occurs. The Jones Act also requires that all United States-flag vessels be manned by United States citizens. Foreign seamen generally receive lower wages and benefits than those received by United States citizen seamen. This requirement significantly increases operating costs of United States-flag vessel operations compared to foreign-flag vessel operations. Certain foreign governments subsidize their nations' shipyards. This results in lower shipyard costs both for new vessels and repairs than those paid by United States-flag vessel owners. 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 United States-flag operators than for owners of vessels registered under foreign flags of convenience. Following Hurricane Katrina, and again after Hurricane Rita, emergency suspensions of the Jones Act were effectuated by the United States government. The last suspension ended on October 24, 2005. Future suspensions of the Jones Act or other similar actions could adversely affect our cash flow. 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 president of the United States of a national emergency or a threat to the national security, the United States Secretary of Transportation may requisition or purchase any vessel or other watercraft owned by United States citizens (including us, provided that we are considered a United States citizen for this purpose). If one of our tow boats or barges were purchased or requisitioned by the United States 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.

For additional information regarding the potential impact of federal, state or local regulatory measures on our business, please read Item 1A "Risk Factors" of this annual report.

Environmental and Safety Matters

Our pipelines and other facilities are subject to multiple environmental obligations and potential liabilities under a variety of 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"); and 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

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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 influence our financial position, results of operations and cash flows. If an accidental 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 jointly and severally 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 materially affect 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, other than certain matters discussed in Note 18 of the Notes to Consolidated Financial Statements under Item 8 of this annual report, 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 clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, and thus there can be no 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 business, financial position, results of operations and cash flows. Below is a discussion of the material environmental laws and regulations that relate to our business.

Air Emissions

Our operations are subject to the CAA and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including 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 permits and related compliance under the CAA, as well as recent or soon to be adopted changes to state implementation plans for controlling air emissions in regional, non-attainment areas, may require our operations to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies. In addition, some of our facilities are included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under the CAA. 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. 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.

In response to certain scientific studies suggesting that emissions of certain gases, commonly referred to as “greenhouse gases” and including carbon dioxide and methane, are contributing to the warming of the Earth’s atmosphere and other climatic changes, the U.S. Congress has been actively considering legislation to reduce such emissions. On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 (“ACESA”), which would establish an economy-wide cap-and-trade program intended to reduce U.S. emissions of “greenhouse gases” including carbon dioxide and methane that may contribute to warming of the Earth’s atmosphere and other climatic changes. ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80% reduction of such emissions by 2050. Under this legislation, the Environmental Protection Agency ("EPA") would issue a capped and steadily declining number of tradable emissions

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allowances to major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. The costs of these allowances would be expected to escalate significantly over time. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions and President Obama has indicated his support of legislation to reduce greenhouse gas emissions through an emission allowance system. Although it is not possible at this time to predict when the Senate may act on climate change legislation or how any bill passed by the Senate would be reconciled with ACESA, any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the natural gas or other hydrocarbon products that we transport, store or otherwise handle in connection with our midstream services.

In addition, on December 7, 2009, the EPA announced its finding that emissions of greenhouse gases presented an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. In late September 2009, the EPA had proposed two sets of regulations in anticipation of finalizing its endangerment finding that would require a reduction in emissions of greenhouse gases from motor vehicles and, also, could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010.

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 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 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 and 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.

Even if such legislation is not adopted at the national level, more than one-third of the states have begun taking actions to control and/or reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Although most of the state-level initiatives have to date focused on large sources of greenhouse gas emissions, such as coal-fired electric plants, it is possible that smaller sources of emissions could become subject to greenhouse gas emission limitations or allowance purchase requirements in the future. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial position and results of operations.

Other Potential Impacts of Climate Change

Over the last hundred years or so, certain instrumental temperature records have evidenced a general increase in global mean temperature. As a result, certain public advocacy groups attribute this rise to a phenomenon termed “global warming.” Proponents of this theory argue that man-made greenhouse gases have produced observable changes in the environment such as shrinkage of the Arctic ice caps, releases of terrestrial carbon from permafrost regions and increases in sea level. In addition, these individuals believe that global warming will result in a continued increase in global average temperatures over the course of this century, with a probable increase in the frequency of extreme weather events, and changes in rainfall patterns. Based on computer models promoted by these groups, certain areas of the globe might benefit from such changes, while other areas would experience costs. Severe global climate change could even result in reduced diversity of ecosystems and the extinction of certain species.

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There is considerable debate in public and private forums as to whether global warming is actually occurring and, if it is, its consequences. 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 may be at increased risk due to flooding or more frequent and severe weather events. Also, a reduction in the demand for hydrocarbon products that are deemed to contribute to greenhouse gases may reduce volumes available to us for processing, transportation, marketing and storage. Unfortunately, there is currently no public consensus regarding global warming, and the scientific community is divided on the subject. We are providing this disclosure regarding the potential physical effects of global warming based on publicly available information and opinions on the matter. As a commercial enterprise, we are not in a position to validate or repudiate the existence of global warming.

Water

The CWA and comparable state laws impose strict controls on the discharge of oil and its derivatives into navigable 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 navigable 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. These permits may require us to monitor and sample the storm water run-off. The CWA and regulations implemented thereunder further prohibit discharges of dredged and fill material in wetlands and other waters of the United States 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 operations.

The primary federal law for oil spill liability is the OPA, which addresses three principal areas of oil pollution: prevention, containment and cleanup and liability. OPA applies to vessels, offshore platforms and onshore facilities, including terminals, pipelines and transfer facilities. In order to handle, store or transport oil, shore facilities are required to file oil spill response plans with the USCG, the United States Department of Transportation Office of Pipeline Safety ("OPS") or the EPA, as appropriate. Numerous states have enacted laws similar to OPA. Under 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 as a result of past operations, we believe any such contamination could be controlled or remedied without having a material adverse effect on our financial position, 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. Amendments to RCRA required the EPA to promulgate regulations banning the land disposal of all hazardous wastes unless the wastes meet certain treatment standards or the land-disposal method meets certain waste containment criteria. In the past, although we utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons and other materials may have been disposed of or released. In the future, we may be required to remove or remediate these materials.

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Environmental Remediation

The CERCLA, also known as "Superfund," imposes liability, 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, these persons 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 also authorizes 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 generate wastes that may fall within CERCLA's definition of a "hazardous substance." In the event a disposal facility previously used by us requires clean up in the future, we may be responsible under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed.

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 Secretary of Transportation. We believe we are in material compliance with these HLPSA 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 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 must be developed by August 1, 2011 and implemented by February 2, 2012. We believe we are in material compliance with these DOT regulations.

In addition, we are subject to the DOT Integrity Management regulations, 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 buffer area around "unusually sensitive areas." We have identified our HCA pipeline segments and developed an appropriate Integrity Management Program.

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 Occupational Safety and Health Act ("OSHA") Process Safety Management ("PSM") regulations (see "Safety Matters" below) to minimize the offsite consequences of

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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.

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.

We 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 EPA 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.

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. For additional information regarding the ASA, see "EPCO ASA" in Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. As of December 31, 2009, there were approximately 4,800 EPCO personnel who spend all or a portion of their time engaged in our business. Approximately 3,300 of these individuals devote all of their time performing administrative, commercial and operating duties for us. The remaining approximate 1,500 personnel are part of EPCO's shared service organization and spend a portion of their time engaged in our business.

Available Information

As a publicly traded partnership, we electronically file certain documents with the U.S. Securities and Exchange Commission ("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, including us.

We provide electronic access to our periodic and current reports on our Internet website, www.epplp.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 document.

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Item 1A. Risk Factors.

An investment in our common units involves certain risks. If any of these risks were to occur, our business, financial position, results of operations and cash flows could be materially adversely affected. In that case, the trading price of our common units could decline and you could lose part or all of your investment.

The following section lists the key current risk factors as of the date of this filing that may have a direct and material impact on our business, financial position, results of operations and cash flows.

Risks Relating to Our Business

Changes in demand for and production of hydrocarbon products may materially adversely affect our financial position, results of operations and cash flows.

We operate predominantly in the midstream energy sector which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs, crude oil and refined products. As such, our financial position, results of operations and cash flows may be materially adversely affected by changes in the prices of hydrocarbon products and by changes in the relative price levels among hydrocarbon products. Changes in prices may impact demand for hydrocarbon products, which in turn may impact production, demand and volumes of product for which we provide services. We may also incur credit and price risk to the extent counterparties do not perform 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 2008 ranged from a high of $13.58 per MMBtu to a low of $5.29 per MMBtu. In 2009, the same index ranged from a high of $6.07 per MMBtu to a low of $2.51 per MMBtu.

Generally, the prices of hydrocarbon products are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional uncontrollable factors. Some of these factors include:

§ the level of domestic production and consumer product demand;

§ the availability of imported oil and natural gas and actions taken by foreign oil and natural gas producing nations;

§ the availability of transportation systems with adequate capacity;

§ the availability of competitive fuels;

§ fluctuating and seasonal demand for oil, natural gas and NGLs;

§ the impact of conservation efforts;

§ the extent of governmental regulation and taxation of production; and

§ the overall economic environment.

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 may materially adversely affect 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 meet their obligations to us.

With respect to our Petrochemical & Refined Products Services segment, market demand and our revenues from these businesses can also be adversely affected by different end uses of the products we transport, market or store. For example:

- § demand for gasoline depends upon market price, prevailing economic conditions, demographic changes in the markets we serve and availability of gasoline produced in refineries located in these markets;

- § demand for distillates is affected by truck and railroad freight, the price of natural gas used by utilities that use distillates as a substitute and usage for agricultural operations;

- § demand for jet fuel depends on prevailing economic conditions and military usage; and

- § propane deliveries are generally sensitive to the weather and meaningful year-to-year variances have occurred and will likely continue to occur.

A decline in the volume of natural gas, NGLs and crude oil delivered to our facilities could adversely affect our financial position, results of operations and cash flows.

Our profitability could be materially impacted by a decline in the volume of natural gas, NGLs and crude oil transported, gathered or processed at our facilities. A material decrease in natural gas or crude oil production or crude oil refining, as a result of depressed commodity prices, a decrease in domestic and international exploration and development activities or otherwise, could result in a decline in the volume of natural gas, NGLs and crude oil handled by our facilities and other energy logistic assets.

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 are beyond our control and 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 offshore platforms, natural gas processing plants, natural gas, crude oil and NGL pipelines, and NGL fractionators, which would have a material adverse affect on our financial position, results of operations and cash flows.

In addition, imported liquefied natural gas ("LNG") may become a significant component of future natural gas supply to the United States. Much of this increase in LNG supplies may be imported through new LNG facilities that have currently been developed or new LNG facilities that have been announced to be developed over the next decade. We cannot predict which, if any, of these announced, but as yet unbuilt, projects will be constructed. In addition, anticipated increases in future natural gas supplies may not be made available to our facilities and pipelines if (i) a significant number of these new projects fail to be developed with their announced capacity, (ii) there are significant delays in such development, (iii) they are built in locations where they are not connected to our assets or (iv) they do not influence sources of supply on our systems. If the expected increase in natural gas supply through imported LNG is not realized, projected natural gas throughput on our pipelines would decline, 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 materially adversely affect our financial position, results of operations and cash flows.

A decrease in demand for NGL products by the petrochemical, refining or heating industries could materially adversely affect our financial position, results of operations and cash flows. Decreases in such demand may be caused by general 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 or the content of motor gasoline or other reasons. For example:

Ethane. Ethane is primarily used in the petrochemical industry as feedstock for 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 by NGL producers falls), it may be more profitable for natural gas producers to leave the ethane in the natural gas stream to be burned as fuel than to extract the ethane from the mixed NGL stream for sale as an ethylene feedstock.

Propane. 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.

Isobutane. A reduction in demand for motor gasoline additives may reduce demand for isobutane. During periods in which the difference in market prices between isobutane and normal butane is low or inventory values are high relative to current prices for normal butane or isobutane, our operating margin from selling isobutane could be reduced.

Propylene. 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 transport.

We face competition from third parties in our midstream businesses.

Even if crude oil and natural gas reserves exist in the areas accessed by our facilities and are ultimately produced, we may not be chosen by the producers in these areas to gather, transport, process, fractionate, store or otherwise handle the hydrocarbons that are produced. We compete with others, 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 compete with other pipelines and marine transportation companies in the areas they serve. We also compete with trucks and railroads in some of the areas we serve. Substantial new construction of inland marine vessels could create an oversupply and intensify competition for our marine transportation business. Competitive pressures may adversely affect our tariff rates or volumes shipped.

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 has intensified 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 and NGLs.

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 price 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. If production delivered to our gathering system declines, our revenues from such operations will decline.

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

As of December 31, 2009, we had approximately $9.76 billion of consolidated senior long-term debt principal outstanding and approximately $1.53 billion of junior subordinated debt principal outstanding. This amount includes $1.95 billion of new EPO notes issued in connection with the TEPPCO Merger (exchanged for TEPPCO's previously tendered notes) and $457.3 million outstanding under Duncan Energy Partners' revolving credit facility and term loan. The amount of our future debt could have significant effects on our operations, including, among other things:

§ a substantial portion of our cash flow, including that of Duncan Energy Partners, 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 view our consolidated debt level negatively;

§ covenants contained in our existing and future credit and debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business, 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 create, 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 credit facilities, see Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our credit agreements and each of our indentures for our public debt contain conventional 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, the amount of our debt maturing in the next several years and current maturities, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, then we could experience an increase in our borrowing costs, difficulty assessing capital markets and/or a reduction in the market price of our common units. 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 securities 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

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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 to enhance our ability to compete effectively and diversifying our asset portfolio, thereby providing more stable cash flow. We regularly consider and pursue potential joint ventures, standalone projects or other transactions that we believe may present opportunities to realize synergies, expand our role in the energy infrastructure business and increase our market position.

We will require substantial new capital to finance the future development and acquisition of assets and businesses. 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 necessary funds on satisfactory terms, if at all.

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

We also compete for the types of assets and businesses we have historically purchased or acquired. Increased competition for a limited pool of assets could result in our losing to other bidders more often or acquiring assets at less attractive prices. Either occurrence would 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 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 materially adversely affect our business, financial position, results of operation and cash flows.

As of December 31, 2009, we had outstanding $11.35 billion of consolidated debt. Of this amount, approximately $1.34 billion, or 11.8%, 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. We have $54.0 million of 8.70% fixed-rate debt that matured on March 1, 2010, and $500.0 million of 4.95% fixed-rate senior notes maturing in June 2010. In 2011, 2012 and 2013, we have $450.0 million, $1.0 billion and $1.2 billion, respectively, of senior notes maturing. In addition, our $1.75 billion revolving credit facility matures in 2012 and Duncan Energy Partners' revolving credit facility and term loan totaling $582.3 million mature in 2011.

The rate on our June 2009 issuance of $500.0 million of Senior Notes due August 2012 was 4.6%. The rate on our September 2009 issuance of $500.0 million of Senior Notes due 2020 was 5.25%, and the rate on our September 2009 issuance of $600.0 million of Senior Notes due 2039 was 6.125%. Should interest rates increase significantly, the amount of cash required to service our debt would increase. As a result, our financial position, results of operations and cash flows, could be materially adversely affected.

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, our financial position, results of operations and cash flows could be materially adversely affected by significant increases in interest rates.

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An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular, for yield-based equity investments such as our common units. Any such reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

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

We have announced and are engaged in several construction projects involving existing and new facilities for which we have expended or will expend significant capital, and our operating cash flow from a particular project may not increase until a period of time after its completion. For instance, if we build a new pipeline or platform or expand an existing facility, the design, construction, development and installation may occur over an extended period of time, and we may not receive any material increase in operating cash flow from that 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 (either ourselves or Duncan Energy Partners may do so) that we believe complement our existing operations. We may be unable to successfully integrate and manage 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 negatively impact our financial position, results of operations and cash flows.

Moreover, acquisitions and business expansions involve numerous risks, including but not limited to:

§ difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments;

§ establishing the internal controls and procedures that 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 an 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, may not be fully realized, if at all.

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

Even if we make acquisitions that we believe will increase our cash from operations, these acquisitions may nevertheless reduce our cash from operations on a per unit basis. Any acquisition involves assumptions that may not materialize and potential risks that may occur. These risks include our inability to achieve our 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 you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

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

We have significant expenditures for the development and construction of midstream energy infrastructure assets, including construction and development projects with 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 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 Gulf Coast may cause delays, shortages of skilled labor and additional expenses for these construction and development projects, as were experienced with Hurricanes Gustav and Ike in 2008.

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 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 increases in revenues 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 growth in production 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;

§ where we do rely on third-party estimates of reserves in making a decision to construct facilities, these estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating reserves;

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§ the completion or success of our project may depend on the completion of a project that we do not control, such as a refinery, 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.

A significant amount of our common units and all of our Class B units that are owned by EPCO and certain of its affiliates are pledged as security under the credit facility of an affiliate of EPCO. Additionally, all of the member interests in our general partner and substantially all of our common units that are owned by Enterprise GP Holdings are pledged under its credit facility. Upon an event of default under either of these credit facilities, a change in ownership or control of us could ultimately result.

An affiliate of EPCO has pledged a significant amount of its common units and all of its Class B units in us as security under its credit facility. This credit facility contains customary and other events of default relating to defaults 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 us. In addition, the 100% membership interest in our general partner and 20,242,179 of our common units that are owned by Enterprise GP Holdings are pledged under Enterprise GP Holdings' credit facility. Enterprise GP Holdings' credit facility contains customary and other events of default. Upon an event of default, the lenders under Enterprise GP Holdings' credit facility could foreclose on Enterprise GP Holdings' assets, which could ultimately result in a change in control of our general partner and a change in the ownership of our common units held by Enterprise GP Holdings.

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

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 and Enterprise GP Holdings to service such indebtedness. Any distributions by us and Enterprise GP Holdings 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.

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.

We are a holding company with no business operations, and our operating subsidiaries conduct all of our operations and own all of our operating assets. Our only significant assets are the ownership interests we own in our operating subsidiary, EPO. As a result, we depend upon the earnings and cash flow 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

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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. For example, all cash flows from Evangeline are currently used to service its debt.

As of December 31, 2009, EPO also owned 33,783,587 common units of Duncan Energy Partners, representing approximately 58.6% of its outstanding common units and 100% of its general partner. EPO also owned noncontrolling interests in subsidiaries of Duncan Energy Partners that held total assets of approximately $4.7 billion as of December 31, 2009. With respect to three subsidiaries of Duncan Energy Partners acquired from us on December 8, 2008 that held approximately $3.7 billion of total assets as of December 31, 2009, Duncan Energy Partners has effective priority rights to specified quarterly distribution amounts ahead of distributions on our retained equity interests in these subsidiaries.

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. Three 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.

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 that joint venture. These participation and protective features customarily include a corporate governance structure that requires at least a majority-in-interest vote to authorize many basic activities 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 and transactions not in the ordinary course of 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.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow and, accordingly, affect the market price of our common units.

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 lbs 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 risk.

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If one or more facilities that are owned by us or that deliver crude oil, natural gas or other products to us are damaged by severe weather or any other disaster, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our control. These interruptions might involve significant damage to people, property or the environment, and repairs might 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' natural gas 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 common units.

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, change in the insurance markets subsequent to the hurricanes in 2005 and 2008 have made it more difficult for us to obtain certain types of coverage. As a result, EPCO may not be able to renew existing insurance policies on behalf of us 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, 2009, our balance sheet reflected $2.02 billion of goodwill and $1.06 billion of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. Generally accepted accounting principles in the United States ("GAAP") 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 charge to earnings with a correlative effect on partners' equity and balance sheet leverage as measured by debt to total capitalization.

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

We historically have sought to limit a portion of the adverse effects resulting from changes in energy commodity prices and interest rates by using financial derivative instruments and other hedging mechanisms from time to time. 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. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is imperfect, or hedging 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.

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 for 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 United States. 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. During 2009, our largest non-affiliated customer based on revenues was Shell, which accounted for 9.8% of our revenues. During 2008 and 2007, our largest non-affiliated customer based on revenues was Valero, which accounted for 11.2% and 8.9%, respectively, of our revenues.

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.

To enhance utilization of certain assets and our operating income, we purchase petroleum products. Generally, it is our policy to maintain a position that is substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Through these transactions, we seek to establish 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.

Our pipeline integrity program and periodic tank maintenance requirements may impose significant costs and liabilities on us.

The DOT issued final rules (effective March 2001 with respect to hazardous liquid pipelines and February 2004 with respect to natural gas pipelines) requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in HCAs. The final rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. At this time, we cannot predict the ultimate costs of compliance with this rule because those costs will depend on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing that is required by the rule. 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.

In June 2008, the DOT issued a Final Rule extending 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." The issuance of these new 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.

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.

Environmental costs and liabilities and changing environmental regulation, including climate change regulation, could affect our results of operations, cash flows and financial condition.

Our operations are subject to extensive federal, state and local regulatory requirements relating to environmental affairs, health and safety, waste management and chemical and petroleum products. 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, impose strict, joint and several liability for costs required to cleanup 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.

We will make expenditures in connection with environmental matters as part of normal capital expenditure programs. However, future environmental law developments, such as stricter laws, regulations, permits or enforcement policies, could significantly increase some costs of our operations, including the handling, manufacture, use, emission or disposal of substances and wastes.

Climate change regulation is one area of potential future environmental law development. Certain studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases," may be contributing to warming of the Earth's atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases. The U.S. Congress is considering legislation to reduce emissions of greenhouse gases. In addition, at least nine states in the Northeast and five states in the West have developed initiatives to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs.

On December 7, 2009, the EPA announced its findings that emissions of "greenhouse gases" present an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. In late September 2009, the EPA had proposed two sets of CAA regulations in anticipation of finalizing its endangerment findings that would require a reduction in emissions of greenhouse gases from motor vehicles and, also, could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, on September 22, 2009, the EPA issued a final CAA rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. These regulations will require reporting for some of our facilities, and additional EPA regulations expected to be adopted in 2010 will require other of our facilities to report their greenhouse gas emissions, possibly beginning in 2012 for emissions occurring in 2011.

Also, on June 26, 2009, the U.S. House of Representatives passed the ACESA, which would establish an economy-wide cap-and-trade program intended to reduce U.S. emissions of “greenhouse gases.” ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. The cost of these allowances would be expected to escalate significantly over time. The net effect of ACESA would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions and the Obama Administration has indicated its support of legislation to reduce greenhouse gas emissions through an emission allowance system.

Although it is not possible at this time to predict when the Senate may act on climate change legislation or how any bill passed by the Senate would be reconciled with ACESA, the adoption and implementation of any CAA regulations, and any future federal, state or local laws or implementing regulations that may be adopted to address greenhouse gas emissions, could require us to incur increased operating costs and could adversely affect demand for the crude oil, natural gas and other hydrocarbon products that we transport, store or otherwise handle in connection with our midstream services. The effect on our operations could include increased costs to operate and maintain our facilities, measure and report our emissions, 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. 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.

Our marine transportation operations are also subject to state and local laws and regulations that control the discharge of pollutants into the environment or otherwise relate to environmental protection. Compliance with such laws, regulations and standards may require installation of costly equipment or operational changes. Failure to comply with applicable laws and regulations may result in administrative and civil penalties, criminal sanctions or the suspension or termination of our marine operations. Some environmental laws often impose strict liability for remediation of spills and releases of oil and hazardous substances, which could subject us to liability without regard to whether we were negligent or at fault. Under the OPA, owners, operators and bareboat charterers are jointly and severally strictly liable for the discharge of oil within the internal and territorial waters of, and the 200-mile exclusive economic zone around, the United States. Additionally, an oil spill from one of our vessels could result in significant liability, including fines, penalties, criminal liability and costs for natural resource damages. The potential for these releases could increase if we increase our fleet capacity. In addition, most states bordering on a navigable waterway have enacted legislation providing for potentially unlimited liability for the discharge of pollutants within their waters.

Global warming, if occurring, may also impact our operations directly, including increased maintenance costs for our facilities, increased flooding and severe weather risks for our facilities that are located in low-lying areas and coastal regions, and reduced demand for hydrocarbon products that may reduce demand and volumes of the products that we process, transport, market and store.

Federal, state or local regulatory measures could materially adversely affect our business, results of operations, cash flows and financial condition.

The FERC regulates our interstate natural gas pipelines and natural gas storage facilities under the NGA, and 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 the services, terms and condition of service and certification and construction of new facilities. The FERC requires that our services are provided on a non-discriminatory basis so that all shippers have open access to our pipelines and storage. Pursuant to the

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FERC's jurisdiction over interstate 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 interests in natural gas pipeline facilities offshore from Texas and Louisiana. These facilities are subject to regulation by the FERC and other federal agencies, including the Department of Interior, under the Outer Continental Shelf Lands Act, and by the DOT's OPS under the Natural Gas Pipeline Safety Act.

Our intrastate NGL and natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas, and by the FERC pursuant to Section 311 of the NGPA. We also have natural gas underground storage facilities in Louisiana, Mississippi and Texas. Although state regulation is typically less onerous than at the FERC, proposed and existing rates subject to state regulation and the provision of services on a non-discriminatory 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, FERC regulation still significantly affects our natural gas gathering business. In recent years, the FERC has pursued pro-competition policies in its regulation of interstate natural gas pipelines. If the FERC does not continue this approach, it could have an adverse effect on the rates we are able to charge in the future. In addition, our natural gas gathering operations could be adversely affected in the future should they become subject to the application of federal regulation of rates and services or if the states in which we operate adopt policies imposing more onerous regulation on gathering. 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 manning, construction and operation of marine vessels may significantly affect our marine transportation operations. Many aspects of the marine industry are subject to extensive governmental regulation by the USCG, the DOT, the Department of Homeland Security, the National Transportation Safety Board and the U.S. Customs and Border Protection, and to regulation by private industry organizations such as the ABS. The USCG and the National Transportation Safety Board 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 Items 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.

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 have a material adverse effect on our business, financial position, results of operations and ability to make distributions to unitholders.

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Our rates are subject to review and possible adjustment by federal and state regulators, which could have a material adverse effect on our financial condition and results of operations.

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. The FERC and interested parties can also challenge tariff rates that have become final and effective. The FERC also can order reparations for overcharges effective 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 producer price index for finished goods. 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 owner of its interests has 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 16, 2005 order were appealed to the United States 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.

In December 2006, the FERC issued a new order addressing rates on another pipeline. In the new order, 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.

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In April 2008, the FERC issued a Policy Statement in which it declared that it would permit master limited partnerships ("MLPs") to be included in rate of return proxy groups for determining rates for services by natural gas and 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.

The ultimate outcome of these proceedings is not certain and could result in changes to the FERC's treatment of income tax allowances in cost of service as well as rates of return, particularly with respect to pipelines organized as partnerships. The outcome of these ongoing proceedings could adversely affect our revenues for any of our rates that are calculated using cost of service rate methodologies.

Our marine transportation business would be adversely affected if we failed to comply with the Jones Act provisions on coastwise trade, or if those provisions were modified, repealed or waived.

We are subject to the Jones Act and other federal laws that restrict maritime transportation between points in the United States to vessels built and registered in the United States 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 the past, interest groups have lobbied Congress to repeal the Jones Act to facilitate foreign flag competition for trades and cargoes currently reserved for U.S.-flag vessels under the Jones Act and cargo preference laws. We believe that interest groups may continue efforts to modify or repeal the Jones Act and cargo preference laws currently benefiting U.S.-flag vessels. If these efforts are successful, it could result in increased competition, which could reduce our revenues and cash available for distribution.

The Secretary of the Department of Homeland Security is vested with the authority and discretion to waive the coastwise laws to such extent and upon such terms as he may prescribe whenever he deems that such action is necessary in the interest of national defense. For example, in response to the effects of Hurricanes Katrina and Rita, the Secretary of the Department of Homeland Security waived the coastwise laws generally for the transportation of petroleum products from September 1 to September 19, 2005 and from September 26, 2005 to October 24, 2005. In the past, the Secretary of the Department of Homeland Security has waived the coastwise laws generally for the transportation of petroleum released from the Strategic Petroleum Reserve undertaken in response to circumstances arising from major natural disasters. Any waiver of the coastwise laws, whether in response to natural disasters or otherwise, could result in increased competition from foreign marine vessel operators, which could reduce our revenues and cash available for distribution.

We depend on the leadership and involvement of key personnel for the success of our businesses.

We depend on the leadership, involvement and services of key personnel. The loss of leadership and involvement or the services of certain key members of our senior management team, including Dan L. Duncan, could have a material adverse effect on our business, financial position, results of operations, cash flows and market price of our securities.

EPCO's employees may be subjected to conflicts in managing our business and the allocation of 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 officers are also officers of EPCO and other affiliates of EPCO. These relationships may create conflicts of interest regarding corporate opportunities and other matters, and the resolution of any such conflicts may not always be in our or our unitholders' best interests. In addition,

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these overlapping officers and employees allocate their time among us, EPCO and other affiliates of EPCO. These officers and employees face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations and financial condition.

We have entered into an ASA that governs business opportunities among entities controlled by EPCO, which includes us and our general partner, Enterprise GP Holdings and its general partner and Duncan Energy Partners and its general partner. For detailed information regarding how business opportunities are handled within the EPCO group of companies, see Item 13 of this annual report.

We do not have a separate compensation committee, and aspects of the compensation of our executive officers and other key employees, including base salary, are not reviewed or approved by our independent directors. 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.

The global financial crisis and its ongoing effects may have impacts on our business and financial condition that we currently cannot predict.

We may face significant challenges if conditions in the financial markets revert to those that existed in the fourth quarter of 2008 and during 2009. Our ability to access the capital markets may be severely restricted at a time when we would like, or need, to do so, which could have an adverse impact on our ability to meet capital commitments and achieve the flexibility needed to react to changing economic and business conditions. The credit crisis could have a negative impact on our lenders or customers, causing them to fail to meet their obligations to us. Additionally, demand for our services and products depends on activity and expenditure levels in the energy industry, which are directly and negatively impacted by depressed oil and gas prices. Also, a decrease in demand for NGLs by the petrochemical and refining industries due to a decrease in demand for their products as a result of general economic conditions would likely impact demand for our services and products. Any of these factors could lead to reduced usage of our pipelines and energy logistics services, which could have a material negative impact on our revenues and prospects.

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:

§ the ownership interest of a unitholder immediately prior to the issuance will decrease;

§ the amount of cash available for distributions on each common unit may decrease;

§ the ratio of taxable income to distributions may increase;

§ the relative voting strength of each previously outstanding common unit may be diminished; and

§ the market price of our common units may decline.

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We may not have sufficient cash from operations to pay cash distributions at the current level following establishment of cash reserves and payments of fees and expenses, including payments to EPGP.

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 EPGP. These factors include but are not limited to the following:

§ the volume of the products that we handle and the prices we receive for our services;

§ the level of our operating costs;

§ the level of competition in our business segments and marketing areas;

§ prevailing economic conditions, including the price of and demand for oil, natural gas and other products we transport, store and market;

§ the level of capital expenditures we make;

§ the amount and cost of capital we can raise compared to the amount of our capital expenditures and debt maturities;

§ the restrictions contained in our debt agreements and our debt service requirements;

§ fluctuations in our working capital needs;

§ the weather in our operating areas;

§ cash outlays for acquisitions, if any; and

§ the amount, if any, of cash reserves required by EPGP in its sole discretion.

In addition, you should be aware that the amount of cash we have available for distribution depends primarily on our cash flow, including cash flow from financial reserves and working capital borrowings, not solely on profitability, which is affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and we may not make distributions during periods when we record net income.

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 reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units and other limited partner interests may decrease in correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

Cost reimbursements and fees due to EPCO and its affiliates, including our general partner may be substantial and will reduce our cash available for distribution to holders of our units.

Prior to making any distribution on our units, we will reimburse EPCO and its affiliates, including officers and directors of EPGP, for all expenses they incur on our behalf, including allocated overhead. These amounts will include all costs incurred in managing and operating us, including costs for rendering administrative staff and support services to us, and overhead allocated to us by EPCO. The payment of these amounts could adversely affect our ability to pay cash distributions to holders of our units. 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.

EPGP 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 EPGP and its affiliates have duties to manage EPGP in a manner that is beneficial to its members. At the same time, EPGP has duties to manage our partnership in a manner that is beneficial to us. Therefore, EPGP'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 EPGP or EPCO to pursue a business strategy that favors us;

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

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

§ EPGP is allowed to resolve any conflicts of interest involving us and EPGP and its affiliates;

§ EPGP is allowed to 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 unitholders;

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

§ affiliates of EPGP may compete with us in certain circumstances;

§ EPGP 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, EPGP may cause us to borrow funds in order to permit the payment of distributions, even if the purpose or effect of the borrowing is to make incentive distributions;

§ our partnership agreement does not restrict EPGP from causing 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;

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

- § EPGP controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- § EPGP decides whether to retain separate counsel, accountants or others to perform services for us.

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We have significant business relationships with entities controlled by Dan L. Duncan, including EPCO. For detailed information on these relationships and related transactions with these entities, see Item 13 of this annual report.

Unitholders have limited voting rights and are not entitled to elect our general partner or its directors, which could lower the trading price of our common units. 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 EPGP or its directors and will have no right to elect our general partner or its directors on an annual or other continuing basis. The Board of Directors of our general partner, including the independent directors, is chosen by the owners of the general partner and not by the unitholders.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have no practical ability to remove EPGP or its officers or directors. EPGP 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. Because affiliates of EPGP currently own approximately 31% of our outstanding common units, the removal of EPGP as our general partner is highly unlikely without the consent of both EPGP 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 or reduction 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 the manner or direction of 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 or reduction of a takeover premium in the trading price.

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

If at any time EPGP and its affiliates own 85% or more of the common units then outstanding, EPGP 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 a sale of their 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:

- § we were conducting business in a state, but had not complied with that particular state's partnership statute; or
- § 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 Enterprise GP Holdings or its affiliates to transfer their 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 or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution to our common unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. 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 a maximum of 35%. Distributions to our unitholders would generally be taxed again as corporate distributions, 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 common unitholders would be substantially

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reduced. Thus, treatment of us as a corporation would result in a material reduction in the after-tax return to our common 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 common 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 U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. 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 exception, which we refer to as the qualifying income exception, for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation, 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 adversely affect an investment in our common units. For example, in response to recent public offerings of interests in the management operations of private equity funds and hedge funds, members of Congress are considering substantive changes to the definition of qualifying income under Section 7704 of the Internal Revenue Code and changing the treatment of certain types of income earned from profits or "carried" interests. It is possible that these legislative efforts could result in changes to the existing U.S. tax laws that affect publicly traded partnerships, including us. Although we are unable to predict whether any of these changes or other proposals will ultimately be enacted, and if so, whether any such changes would be applied retroactively, the enactment of any such changes could negatively impact the value of an investment in our common units.

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 our items of income, gain, loss and deduction between transferors and transferees of the 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 are 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 costs of any contests will be borne by our unitholders and our general partner.

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 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 and our general partner and thus will be borne indirectly by our unitholders and our general partner.

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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.

Common 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 its common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized 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, 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.

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

Investments in common units by tax-exempt entities, such as individual retirement accounts (known as 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 United States 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 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 with all aspects of applicable 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 common 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, including 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. 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.

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

We will be considered to have terminated 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 termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between EPGP and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional common units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and EPGP. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and EPGP, which may be unfavorable to such unitholders. Moreover, under this methodology, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our intangible assets and a lesser portion allocated to our tangible assets. The IRS may challenge our methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between EPGP and certain of our unitholders.

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

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, he would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because 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 he 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.

On occasion, we or our unconsolidated affiliates are named as defendants in legal proceedings relating to our normal business activities, including 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

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and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. We are not aware of any litigation, pending or threatened, that we believe is reasonably likely to have a significant adverse effect on our financial position, results of operations or cash flows. For detailed information regarding our legal proceedings, see Note 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report, which is incorporated by reference into this Item 3.

Item 4. [Reserved]

PART II

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

Market Information and Cash Distributions

Our common units are listed on the NYSE under the ticker symbol "EPD." As of February 1, 2010, there were approximately 1,772 unitholders of record of our common units. The following table presents the high and low sales prices for our common units during the periods indicated (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.

| | Price Ranges | | Cash Distribution History | | |
|---|---|---|---|---|---|
| | High | Low | Per Unit | Record Date | Payment Date |
| 2008 | | | | | |
| 1st Quarter | $32.630 | $26.750 | $0.5075 | Apr. 30, 2008 | May 7, 2008 |
| 2nd Quarter | $32.640 | $29.040 | $0.5150 | Jul. 31, 2008 | Aug. 7, 2008 |
| 3rd Quarter | $30.070 | $22.580 | $0.5225 | Oct. 31, 2008 | Nov. 12, 2008 |
| 4th Quarter | $26.300 | $16.000 | $0.5300 | Jan. 30, 2009 | Feb. 9, 2009 |
| 2009 | | | | | |
| 1st Quarter | $24.200 | $17.710 | $0.5375 | Apr. 30, 2009 | May 8, 2009 |
| 2nd Quarter | $26.550 | $21.100 | $0.5450 | Jul. 31, 2009 | Aug. 7, 2009 |
| 3rd Quarter | $29.450 | $24.500 | $0.5525 | Oct. 30, 2009 | Nov. 5, 2009 |
| 4th Quarter | $32.240 | $27.250 | $0.5600 | Jan. 29, 2010 | Feb. 4, 2010 |

The quarterly cash distributions shown in the table above correspond to cash flows for the quarters indicated. The actual cash distributions (i.e., the payments made to our common unitholders) occur within 45 days after the end of such quarter. We expect to fund our quarterly cash distributions to common unitholders primarily with cash provided by operating activities. For additional information regarding our cash flows from operating activities, see "Liquidity and Capital Resources" included under Item 7 of this annual report. Although the payment of cash distributions is not guaranteed, we expect to continue to pay comparable cash distributions in the future.

Recent Sales of Unregistered Securities

On September 4, 2009, we agreed to issue 5,940,594 common units in a private placement to EPCO Holdings, Inc., a privately held affiliate controlled by Dan L. Duncan, for $150.0 million. The private placement was exempt from the registration requirements of the Securities Act pursuant to Section 4(2) thereof, as a transaction by an issuer not involving any public offering. In accordance with the terms of the private placement, as approved by the Audit, Conflicts and Governance ("ACG") Committee of EPGP's Board of Directors on September 1, 2009, the per unit purchase price of $25.25 was calculated based on a 5% discount to the five-day volume weighted-average price of our common units, as reported by the NYSE at the close of business on September 4, 2009. The common units were issued September 8, 2009.

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Other than as described above, there were no sales of unregistered equity securities during 2009.

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 since 2002 under this program. As of February 1, 2010, we and our affiliates could repurchase up to 618,400 additional common units under this repurchase program.

The following table summarizes our repurchase activity during 2009 in connection with other arrangements:

| Period | Total Number of Units Purchased | Average Price Paid per Unit | Total Number of of Units Purchased as Part of Publicly Announced Plans | Maximum Number of Units That May Yet Be Purchased Under the Plans |
|---|---|---|---|---|
| February 2009 | 1,357 (1) | $ 22.64 | -- | -- |
| May 2009 | 419 (2) | $ 24.69 | -- | -- |
| July 2009 | 610 (3) | $ 28.10 | -- | -- |
| August 2009 | 61,837 (4) | $ 28.00 | -- | -- |
| November 2009 | 9,477 (5) | $ 28.36 | -- | -- |
| December 2009 | 1,657 (6) | $ 29.73 | -- | -- |

(1) Of the 11,000 restricted unit awards that vested in February 2009 and converted to common units, 1,357 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
(2) Of the 1,500 restricted unit awards that vested in May 2009 and converted to common units, 419 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
(3) Of the 2,300 restricted unit awards that vested in July 2009 and converted to common units, 610 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
(4) Of the 229,500 restricted unit awards that vested in August 2009 and converted to common units, 61,837 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
(5) Of the 31,000 restricted unit awards that vested in November 2009 and converted to common units, 9,477 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
(6) Of the 6,200 restricted unit awards that vested in December 2009 and converted to common units, 1,657 of these units were sold back to the partnership 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. This information has been derived from and should be read in conjunction with the audited financial statements. Our results of operations for the years ended December 31, 2008, 2007, 2006 and 2005 and financial position at December 31, 2008, 2007, 2006 and 2005 have been recast to reflect the TEPPCO Merger. The inclusion of TEPPCO and TEPPCO GP in our consolidated financial statements was effective January 1, 2005 because an affiliate of EPCO under common control with us originally acquired ownership interests in TEPPCO GP in February 2005. 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, | | | | |
|---|---|---|---|---|---|
| | 2009 | 2008 | 2007 | 2006 | 2005 |
| Operating results data: (1) | | | | | |
| Revenues | $ 25,510.9 | $ 35,469.6 | $ 26,713.8 | $ 23,612.1 | $ 20,858.3 |
| Income from continuing operations (2) | $ 1,155.1 | $ 1,188.9 | $ 838.0 | $ 786.1 | $ 581.6 |
| Net income | $ 1,155.1 | $ 1,188.9 | $ 838.0 | $ 787.6 | $ 577.4 |
| Net income attributable to Enterprise Products Partners L.P. | $ 1,030.9 | $ 954.0 | $ 533.6 | $ 601.1 | $ 419.5 |
| Earnings per unit: | | | | | |
| Basic and diluted | $ 1.73 | $ 1.84 | $ 0.95 | $ 1.20 | $ 0.90 |
| Other financial data: | | | | | |
| Distributions per common unit (3) | $ 2.1950 | $ 2.0750 | $ 1.9475 | $ 1.8250 | $ 1.6975 |

| | As of December 31, | | | | |
|---|---|---|---|---|---|
| | 2009 | 2008 | 2007 | 2006 | 2005 |
| Financial position data: (1) | | | | | |
| Total assets | $ 26,151.6 | $ 24,211.6 | $ 22,515.5 | $ 19,109.2 | $ 17,486.7 |
| Long-term and current maturities of debt (4) | $ 11,346.4 | $ 11,637.9 | $ 8,771.1 | $ 6,898.9 | $ 6,358.8 |
| Equity (5) | $ 10,042.3 | $ 9,295.9 | $ 9,016.5 | $ 9,124.9 | $ 8,203.8 |
| Total common units outstanding (5) | 605.9 | 441.4 | 435.3 | 432.4 | 389.9 |

(1) In general, our historical operating results and financial position have been affected by numerous transactions, including the TEPPCO Merger, which was completed on October 26, 2009.
(2) Amounts presented for the years ended December 31, 2006 and 2005 are before the cumulative effect of accounting changes.
(3) Distributions per common unit represent declared cash distributions with respect to the four fiscal quarters of each period presented.
(4) In general, the balances of our long-term and current maturities of debt have increased over time as a result of financing all or a portion of acquisitions and other capital spending.

(5) We regularly issue common units through underwritten public offerings and, less frequently, in connection with acquisitions or other transactions. For additional information regarding our equity and unit history, see Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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

For the years ended December 31, 2009, 2008 and 2007.

The following information should be read in conjunction with our consolidated financial statements and our accompanying notes included in this annual report. Our discussion and analysis includes the following:

§ Cautionary Note Regarding Forward-Looking Statements.

§ Overview of Business.

§ Basis of Financial Statement Presentation.

§ Significant Recent Developments – Discusses significant developments during the year ended December 31, 2009 and through the date of this filing.

§ General Outlook for 2010.

§ Results of Operations – Discusses material year-to-year variances in our Statements of Consolidated Operations.

§ Liquidity and Capital Resources – Addresses available sources of liquidity and capital resources and includes a discussion of our capital spending program.

§ Critical Accounting Policies and Estimates.

§ Other Items – Includes information related to contractual obligations, off-balance sheet arrangements and other matters.

Our financial statements have been prepared in accordance with U.S. GAAP.

Cautionary Note Regarding Forward-Looking Statements

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 such 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. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in 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 the 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 North American midstream energy company providing a wide range of 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, Canada and the Gulf of Mexico with domestic consumers and international markets. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the NYSE under the ticker symbol "EPD." We conduct substantially all of our business through EPO. We are owned 98% by our limited partners and 2% by our general partner, EPGP. EPGP is owned 100% by Enterprise GP Holdings.

In connection with the TEPPCO Merger, we revised our business segments. Our reorganized business segments reflect the manner in which these businesses are managed and reviewed by the chief executive officer of our general partner. Under our new business segment structure, we have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

Basis of Financial Statement Presentation

Since Enterprise Products Partners, TEPPCO and TEPPCO GP are under common control of EPCO and its affiliates, the TEPPCO Merger was accounted for at historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. The inclusion of TEPPCO and TEPPCO GP in our consolidated financial statements was effective January 1, 2005 because an affiliate of EPCO under common control with Enterprise Products Partners originally acquired ownership interests in TEPPCO GP in February 2005.

Our consolidated financial statements prior to the TEPPCO Merger reflect the combined financial information of Enterprise Products Partners, TEPPCO and TEPPCO GP on a 100% basis. Third-party and related party ownership interests in TEPPCO and TEPPCO GP are reflected as "Former owners of TEPPCO," a component of noncontrolling interest.

The financial statements of TEPPCO and TEPPCO GP were prepared from the separate accounting records maintained by TEPPCO and TEPPCO GP. All intercompany balances and transactions have been eliminated in consolidation.

There was no change in net income attributable to Enterprise Products Partners L.P. for periods prior to the merger since net income attributable to TEPPCO and TEPPCO GP was allocated to noncontrolling interests. Additionally, there was no change in our reported earnings per unit for such periods. See "Other Items" included within this Item 7 for information regarding total segment gross operating margin, which is a non-generally accepted accounting principle ("non-GAAP") financial measure of segment performance.

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The following information is provided to reconcile total revenues and total gross operating margin for the years ended December 31, 2008 and 2007, as currently presented, with those we previously presented (dollars in millions):

| | For Year Ended December 31, 2008 | For Year Ended December 31, 2007 |
|---|---|---|
| Total revenues, as previously reported | $21,905.6 | $16,950.1 |
| Revenues from TEPPCO | 13,532.9 | 9,658.1 |
| Revenues from Jonah Gas Gathering Company ("Jonah") (1) | 232.8 | 204.1 |
| Eliminations (2) | (201.7) | (98.5) |
| Total revenues, as currently reported | $35,469.6 | $26,713.8 |
| | | |
| Total segment gross operating margin, as previously reported | $2,057.4 | $1,492.1 |
| Gross operating margin from TEPPCO | 501.0 | 434.8 |
| Gross operating margin from Jonah | 157.6 | 125.4 |
| Eliminations (3) | (107.0) | (87.9) |
| Total segment gross operating margin, as currently reported | $2,609.0 | $1,964.4 |

(1) Prior to the TEPPCO Merger, we and TEPPCO were joint venture partners in Jonah. As a result of the merger, Jonah became a consolidated subsidiary.
(2) Represents the eliminations of revenues between Enterprise Products Partners, TEPPCO and Jonah.
(3) Represents equity earnings from Jonah recorded by Enterprise Products Partners and TEPPCO prior to the merger.

Significant Recent Developments

Merger of TEPPCO and TEPPCO GP with Enterprise Products Partners

On October 26, 2009, the related mergers of our wholly owned subsidiaries with TEPPCO and TEPPCO GP were completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of ours and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, were entitled to receive 1.24 of our common units for each TEPPCO unit. In total, we issued an aggregate of 126,932,318 common units and 4,520,431 Class B units (described below) as consideration in the TEPPCO Merger for both TEPPCO units and the TEPPCO GP membership interests. TEPPCO's units, which had been trading on the NYSE under the ticker symbol "TPP," have been delisted and are no longer publicly traded. On October 27, 2009, our TEPPCO and TEPPCO GP equity interests were contributed to EPO, and TEPPCO and TEPPCO GP became wholly owned subsidiaries of EPO.

A privately held affiliate of EPCO exchanged a portion of its TEPPCO units, based on the 1.24 exchange rate, for 4,520,431 of our Class B units in lieu of common units. The Class B units are not entitled to regular quarterly cash distributions for the first sixteen quarters following the closing date of the merger. The Class B units automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth quarterly distribution following the closing date of the merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as our common units.

In connection with the TEPPCO Merger, EPO commenced offers in September 2009 to exchange all of TEPPCO's outstanding notes (a combined principal amount of $2 billion) for a corresponding series of new EPO notes. The purpose of the exchange offer was to simplify our capital structure following the TEPPCO Merger. The exchanges for tendered TEPPCO notes were completed on October 27, 2009. The new EPO notes are guaranteed by Enterprise

Products Partners L.P. The EPO notes issued in the exchange were recorded at the same carrying value as the TEPPCO notes being replaced. Accordingly, we recognized no gain or loss for accounting purposes related to this exchange. All note exchange direct costs paid to third parties have been expensed. In addition to the debt exchange, we gained approval from the requisite TEPPCO noteholders to eliminate substantially all of the restrictive covenants and reporting requirements associated with the remaining TEPPCO notes. Upon the consummation of the TEPPCO Merger, EPO repaid and terminated indebtedness under TEPPCO's revolving credit facility.

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Enterprise Products Partners and Duncan Energy Partners Announce Extension of
Acadian Gas System into Haynesville Shale Supply Basin

In October 2009, we and our affiliate, Duncan Energy Partners, announced plans for our jointly owned Acadian Gas System to extend its Louisiana intrastate natural gas pipeline system into northwest Louisiana to provide producers in the rapidly expanding Haynesville Shale natural gas supply basin with access to additional markets through connections with the Acadian Gas System in south Louisiana and nine major interstate natural gas pipelines ("Haynesville Extension"). The Haynesville Shale producing area is believed to cover approximately 2 million acres in northwest Louisiana, almost all of which is under lease. Production from the approximately 200 wells drilled to date is estimated at more than 1 Bcf/d. Over 400 locations are in various stages of drilling and completion with approximately 150 rigs now working in the region.

As currently designed, the Haynesville Extension will have the potential capacity to transport up to 2.1 Bcf/d of natural gas from the Haynesville area through a 249-mile pipeline that will connect with the existing Acadian Gas System. The pipeline is expected to be in service during the third quarter of 2011.

The Acadian Gas System serves major natural gas markets along the Mississippi River corridor between Baton Rouge and New Orleans and has the ability to make physical deliveries into the Henry Hub. The Haynesville Extension will also have interconnects with major interstate pipelines including Florida Gas, Texas Eastern, Transco, Sonat, Columbia Gulf, Trunkline, ANR, Tennessee Gas and Texas Gas. Together with the capacity of the existing Acadian Gas System, the extension project will provide approximately 6.2 Bcf/d of redelivery capacity into an estimated 12 Bcf/d of available downstream pipeline takeaway capacity. Initially, the project will connect to nine Haynesville Shale producer locations in DeSoto and Red River parishes.

Along with providing much needed natural gas takeaway capacity for growing Haynesville production, the Haynesville Extension is expected to provide shippers the opportunity to benefit from additional pricing points and diverse service options and access to the south Louisiana marketplace. For producers, the more flexible contracting options associated with an intrastate pipeline environment is expected to help facilitate a seamless transaction for the producer from the field to the end user.

Currently, Duncan Energy Partners owns a 66% equity interest in the entities that own the Acadian Gas System, with EPO owning the remaining 34% equity interest. Duncan Energy Partners and EPO are in discussions regarding the funding and related aspects of the Haynesville Extension project.

Enterprise Products Partners and TEPPCO Exit Texas Offshore Port System Partnership

In August 2008, our wholly owned subsidiaries together with Oiltanking formed TOPS. Effective April 16, 2009, our wholly owned subsidiaries dissociated (exited) from TOPS. As a result, operating costs and expenses and net income for the year ended December 31, 2009 reflect a non-cash charge of $68.4 million. This loss represented the forfeiture of our cumulative investment in TOPS through the date of dissociation and reflected our capital contributions to TOPS for construction in progress amounts. On September 17, 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 an additional $66.9 million of expense during 2009 in connection with the payment of this cash settlement. The aggregate $135.3 million of charges recorded during 2009 were classified within the Offshore Pipelines & Services business segment.

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General Outlook for 2010

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 services include global and U.S. economic conditions, the demand for energy, the market price of 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 drilling activities.

The global economic contraction that began in late 2007 appeared to show signs of stabilizing in the second half of 2009 with most of the twenty largest developed economies ("G20") reporting quarter-over-quarter growth in real gross domestic product ("GDP") beginning in the third quarter of 2009. However, approximately 65% of the G20 were still reporting year-over-year contraction in real GDP in 2009. The United States reported quarter-over-quarter real GDP growth of 2.2% and 5.7% for the third and fourth quarters of 2009, respectively, after five quarters of contraction in real GDP since the beginning of 2008. Real GDP growth for 2009 compared to 2008 was 0.1%.

Impacted by general economic conditions and price shock-induced conservation by consumers, U.S. demand for petroleum products and natural gas (as reported by the U.S. Energy Information Administration) for the first ten months of 2009 decreased approximately 5.4% and 2.1%, respectively, from the same periods in 2008 and by approximately 11% and 1.5%, respectively, from the first ten months of 2007. Likewise, U.S. demand for petroleum products for transportation purposes (e.g., motor gasoline, distillate and jet fuel) for the first ten months of 2009 declined by 2.7% and 6.3% compared to the first ten months of 2008 and 2007, respectively. The rate of decline in U.S. demand for petroleum products since mid-2009 appears to be moderating and demand for natural gas since mid-2009 has increased by 1.5% compared to the same period in 2008.

Energy prices have generally rebounded with the recovery in demand, economic growth and stability in the capital markets. The average prices for West Texas Intermediate crude oil and Mont Belvieu ethane for December 2009 increased by approximately 82% and 120%, respectively, from December 2008; while natural gas at the Henry Hub in December 2009 decreased by 8% from December 2008. Notably, there has been a substantial change in the price relationship between natural gas and crude oil. In December 2008, natural gas was priced at 81% of crude oil on an energy equivalent basis compared to 41% in December 2009. We believe changes in the price relationships of crude oil and crude oil derivatives to natural gas and NGLs in the past year could lead to a long-term structural change in feedstock selection by the petrochemical industry.

During 2009 and the beginning of 2010, natural gas and NGLs have a significant price advantage over more costly crude oil and crude oil derivatives (such as naphtha). This has been primarily driven by (i) a decline in global crude oil production; (ii) more government-held acreage being off limits to non-sovereign energy companies; (iii) geopolitical risk; (iv) growing demand for crude oil by China and other developing countries; (v) the globalization of natural gas prices with more LNG facilities becoming operational; and (vi) the technological breakthroughs around the development of natural gas shale resource basins that have decreased finding and development costs.

For ethylene producers, the largest consumers of NGLs, this has meant that ethane and propane were their most consistently profitable feedstocks in 2009 and are forecasted to be so in 2010. This feedstock cost advantage and a weak U.S. dollar provided U.S. ethylene producers with a competitive advantage globally, especially relative to naphtha crackers in Europe and Asia. Per industry publications, approximately 24% of 2009 aggregate domestic production of high density polyethylene ("HDPE"), low density polyethylene ("LDPE") and polyvinyl chloride ("PVC") were for the export market.

U.S. ethylene producers responded by maximizing the use of NGLs as a feedstock, rationalizing some of their facilities and investing capital to modify their furnaces to crack more NGLs. The U.S. ethylene industry consumed almost 1.3 MMBbls/d of NGL feedstocks in December 2009, an 81% increase over 700 MBPD of NGLs consumed in December 2008. We estimate domestic crackers are in the process of adding approximately 100 MBPD of new capacity to crack ethane and propane through modifications to their existing facilities. Certain international ethylene crackers have reacted to the NGL feedstock cost advantage by importing propane to displace crude oil derivatives to feed their heavy crackers, including propane produced in the U.S.

Export ethylene derivative demand remains strong in early 2010, but is expected to moderate as Middle East production increases later this year. Chemical margins in the U.S. are also forecasted to compress due to increased competition, but overall demand for domestically produced ethylene is expected to decline only by approximately 1.5% to 48.3 billion lbs/year in 2010 and then increase 2.3% to 49.4 billion lbs/year in 2011. With the global recession abating, domestic demand is expected to increase, consuming the production that was sold into the export markets in 2008 and 2009.

Strong end user demand for NGLs and increases in NGL-rich natural gas production are expected to (i) keep our natural gas processing plants and NGL fractionators, pipelines and storage facilities operating at high utilization rates; (ii) provide attractive natural gas processing margins for our equity NGL production; and (iii) provide us with opportunities to invest capital to build new natural gas processing, NGL fractionation and pipeline facilities.

At the beginning of 2009, we had opportunities to purchase NGLs and sell them forward for delivery in late 2009 and early 2010 at attractive sales margins. To facilitate this activity, we utilized our NGL storage facilities and pipelines. At the beginning of 2010, these opportunities have largely diminished.

Natural gas prices have significantly declined from a peak of over $13.00 per MMBtu in mid-2008 to $5.35 per MMBtu in December 2009. This price decrease coupled with the residual impact of a higher cost of capital for certain energy companies has generally resulted in energy companies reducing their drilling capital expenditure budgets. This has led to a substantial decrease in the number of rigs drilling for natural gas in the U.S., declining from a peak of 1,606 rigs in August 2008 to a low of 665 rigs in July 2009 as natural gas prices approached a low of $1.88 per MMBtu in September 2009. The natural gas rig count has since rebounded to 878 rigs at the beginning of February 2010. Even though the total natural gas rig count has dropped by almost half, the substantial efficiencies of horizontal drilling in the non-conventional and shale supply 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. The rig count has increased in the developing Haynesville Shale, Marcellus Shale and Eagle Ford Shale area where producers are drilling to hold recently executed leases. Generally, rig counts remain significantly below peak levels in areas with conventional natural gas reserves and areas where producers have leases held by production.

Certain of the large natural gas and NGL producing basins we serve have seen a significant decrease in rig count. In Wyoming, Colorado and New Mexico, rig counts at the end of 2009 had declined 52%, 66% and 49%, respectively, from peak levels during 2008. Given the number of wells waiting to be connected to our pipeline systems, the respective production decline curves and the decline in drilling activity, we believe the aggregate natural gas pipeline volumes transported on our Jonah Gas Gathering, Piceance Basin Gathering and San Juan Gathering systems for 2010 could range from an increase of 5% to a decrease of 5% compared to volumes transported in 2009. Since the end of 2009, the rig counts in Wyoming and New Mexico have increased by 14% and 12%, respectively. These areas have substantial, undeveloped non-conventional natural gas reserves 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 as U.S. natural gas supply and demand becomes more balanced and natural gas prices become less volatile these areas will have an increase in drilling activity to support, and potentially increase, current production levels.

In Texas, the rig count at the end of 2009 was 50% below peak levels during 2008. Since the end of 2009, the rig count in Texas has increased 13%. The rig count in the Barnett Shale area at the end of 2009 was approximately 55% below peak levels. While the Barnett Shale has a significant amount of

undeveloped natural gas reserves at relatively low finding costs, much of the acreage under lease is held by production. Certain energy companies that were active in the Barnett Shale have elected to reallocate a portion of their capital resources in the near term to drill wells in the Haynesville Shale in Louisiana, the Marcellus Shale in Pennsylvania and West Virginia, and the Eagle Ford Shale in South Texas to secure recently acquired leases that are not held by production. Despite the lower rig count in the Barnett Shale and certain other areas of Texas, we expect transportation volumes on our Texas Intrastate System to increase by up to 10% in 2010 with volume growth principally attributable to a full year of operations for the Sherman Extension pipeline and the commencement of operations on the Trinity River Lateral during the third quarter of 2010. Both of these pipelines serve the Barnett Shale region.

South Texas has seen an increase in drilling activity attributable to the development of the Eagle Ford Shale, which runs parallel to the Texas Gulf Coast and adjacent to our Texas Intrastate System. We have completed several small pipeline projects that enable us to gather, transport and process up to 300 MMcf/d of new natural gas production from the Eagle Ford Shale. Generally, energy companies have had early success in the Eagle Ford Shale and several have indicated they plan to accelerate their drilling programs. Production associated with this region includes crude oil, NGL-rich natural gas and lean natural gas. We believe there may be opportunities for us to invest capital to incrementally expand 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.

The rig count in Louisiana has increased 14% since the end of 2008 primarily due to development activities in the Haynesville Shale area of northwest Louisiana. Based on industry success, natural gas production from this region is expected to grow rapidly over the next several years. In the fourth quarter of 2009, we announced that seven energy companies had executed long-term agreements to support the Haynesville Extension expansion of our Acadian Gas System. The Haynesville Extension is a 249-mile, 42-inch pipeline designed to transport up to 2.1 Bcf/d. Construction of the pipeline will begin in 2010 and is scheduled to be completed by the end of the third quarter of 2011.

With respect to our offshore Gulf of Mexico assets, we expect natural gas volumes handled by our Independence Hub platform and Trail pipeline to range from 700 BBtus/d to 800 BBtus/d. Our major crude oil pipelines are expected to transport up to an aggregate 20% increase in volumes as the result of a full year of operations from our Shenzi pipeline and additional volumes from many offshore production facilities that were either idle or in limited service for at least half of 2009 due to repairs to infrastructure damaged by Hurricanes Gustav and Ike in 2008.

Our refined products pipeline generally serves the Petroleum Administration for Defense District (“PADD”) 2 of the U.S. Demand for refined products in this region for 2009 decreased by approximately 8% and 19% from 2008 and 2007, respectively. Commensurately, refined products transportation volumes on our pipelines in 2009 declined by 6.7% and 15.3% compared to 2008 and 2007, respectively. We do not expect any significant improvement in refined product demand in 2010 in this region due to soft economic conditions and ongoing conservation.

We completed the TEPPCO Merger on October 26, 2009. Our commercial, engineering and operating teams have had early success in identifying opportunities to increase revenues and/or lower operating costs by incorporating the former TEPPCO assets into our integrated midstream system. We believe we will find additional opportunities in 2010.

Liquidity Outlook

The debt and equity capital markets have significantly improved since the beginning of 2009. The cost of our term debt and equity capital has generally declined to pre-financial crisis levels. The availability of term debt and equity capital has also improved. The availability of credit commitments from most banks has also improved from a year ago; however, the cost of new bank debt is significantly higher than pre-crisis levels (by approximately 2% on borrowed money) and the term of bank capital is generally limited to no more than three years.



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In January 2010, we completed a public offering of 10,925,000 of our common units, which resulted in net proceeds of $343.1 million. Upon completion of that offering, we had liquidity, unrestricted cash and capacity under our multi-year credit facility, of approximately $2 billion. Based on information currently available, we estimate that our capital expenditures for 2010 will approximate $1.75 billion, which includes approximately $1.5 billion for growth capital projects and $250 million for sustaining capital expenditures. Sustaining capital expenditures in 2010 are expected to be higher than prior years primarily due to pipeline integrity projects on certain of our pipelines. We estimate sustaining capital expenditures for 2011 will be in the range of $210 million to $220 million.

In 2010, we have two notes maturing totaling $554.0 million. A $54.0 million 8.70% note matured on March 1, 2010, and a $500.0 million 4.95% senior note matures on June 1, 2010. We believe we will have sufficient liquidity and access to capital markets to refinance these maturities.

We expect our proactive approach to funding capital spending and other partnership needs, combined with sufficient trade credit to operate our businesses efficiently, and available borrowing capacity under our credit facilities, to provide us with a foundation to meet our anticipated liquidity and capital requirements in 2010. We also believe we will be able to access the capital markets in 2010 to maintain financial flexibility. Based on information currently available to us, we believe we will maintain our investment grade credit ratings and meet our loan covenant obligations in 2010.

We have approximately $3.2 billion of senior notes maturing in the period beginning 2010 through the end of 2013. In addition, we have a $282.3 million bank term loan and bank credit facilities with commitments totaling approximately $2.0 billion maturing during this time period. The U.S. government is expected to run substantial annual budget deficits, exceeding a trillion dollars that will require a corresponding issuance of debt by the U.S. Treasury from 2010 through 2013. 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 large issuance of U.S. Treasury debt and the prevailing economic and capital market conditions will have on the cost and availability of capital. To date, we have executed approximately $550.0 million of interest rate swaps to hedge a portion of our future debt issuance costs to refinance our debt that matures during the 2010 through 2013 time period. We will continue to monitor and evaluate the condition of the capital market and interest rate risk with respect to refinancing these maturities and funding our capital expenditures.

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Results of Operations

Selected Price and Volumetric Data

The following table illustrates 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) | Crude Oil, $/barrel (2) | Ethane, $/gallon (1) | Propane, $/gallon (1) | Normal Butane, $/gallon (1) | Isobutane, $/gallon (1) | Natural Gasoline, $/gallon (1) | Polymer Grade Propylene, $/pound (1) | Refinery Grade Propylene, $/pound (1) |
|---|---|---|---|---|---|---|---|---|---|
| 2007 Averages | $6.86 | $72.24 | $0.79 | $1.21 | $1.42 | $1.49 | $1.68 | $0.52 | $0.47 |
| | | | | | | | | | |
| 2008 | | | | | | | | | |
| 1st Quarter | $8.03 | $97.82 | $1.01 | $1.47 | $1.80 | $1.87 | $2.12 | $0.61 | $0.54 |
| 2nd Quarter | $10.94 | $123.80 | $1.05 | $1.70 | $2.05 | $2.08 | $2.64 | $0.70 | $0.67 |
| 3rd Quarter | $10.25 | $118.22 | $1.09 | $1.68 | $1.97 | $1.99 | $2.52 | $0.78 | $0.66 |
| 4th Quarter | $6.95 | $59.08 | $0.42 | $0.80 | $0.90 | $0.96 | $1.09 | $0.37 | $0.22 |
| 2008 Averages | $9.04 | $99.73 | $0.89 | $1.41 | $1.68 | $1.72 | $2.09 | $0.62 | $0.52 |
| | | | | | | | | | |
| 2009 | | | | | | | | | |
| 1st Quarter | $4.91 | $43.31 | $0.36 | $0.68 | $0.87 | $0.97 | $0.96 | $0.26 | $0.20 |
| 2nd Quarter | $3.51 | $59.79 | $0.43 | $0.73 | $0.93 | $1.11 | $1.21 | $0.34 | $0.28 |
| 3rd Quarter | $3.39 | $68.24 | $0.47 | $0.87 | $1.12 | $1.19 | $1.42 | $0.48 | $0.43 |
| 4th Quarter | $4.16 | $76.19 | $0.67 | $1.09 | $1.39 | $1.49 | $1.64 | $0.50 | $0.44 |
| 2009 Averages | $3.99 | $61.88 | $0.48 | $0.84 | $1.08 | $1.19 | $1.31 | $0.39 | $0.34 |

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including Oil Price Information Service and Chemical Marketing Associates, Inc. ("CMAI"). Natural gas price is representative of Henry-Hub I-FERC. NGL prices are representative of Mont Belvieu Non-TET pricing. Refinery grade propylene represents a weighted-average of CMAI spot prices. Polymer-grade propylene represents average CMAI contract pricing.
(2) Crude oil price is representative of an index price 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. 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 include volumes for newly constructed assets since the dates such assets were placed into service and for recently purchased assets since the date of acquisition.

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2009 | 2008 | 2007 |
| NGL Pipelines & Services, net: | | | |
| NGL transportation volumes (MBPD) | 2,196 | 2,021 | 1,877 |
| NGL fractionation volumes (MBPD) | 461 | 441 | 405 |
| Equity NGL production (MBPD) | 117 | 108 | 88 |
| Fee-based natural gas processing (MMcf/d) | 2,650 | 2,524 | 2,565 |
| Onshore Natural Gas Pipelines & Services, net: | | | |
| Natural gas transportation volumes (BBtus/d) | 10,435 | 9,612 | 8,465 |
| Onshore Crude Oil Pipelines & Services, net: | | | |
| Crude oil transportation volumes (MBPD) | 680 | 696 | 652 |
| Offshore Pipelines & Services, net: | | | |
| Natural gas transportation volumes (BBtus/d) | 1,420 | 1,408 | 1,641 |
| Crude oil transportation volumes (MBPD) | 308 | 169 | 163 |
| Platform natural gas processing (MMcf/d) | 700 | 632 | 494 |
| Platform crude oil processing (MBPD) | 12 | 15 | 24 |
| Petrochemical & Refined Products Services, net: | | | |
| Butane isomerization volumes (MBPD) | 97 | 86 | 90 |
| Propylene fractionation volumes (MBPD) | 68 | 58 | 68 |
| Octane enhancement production volumes (MBPD) | 10 | 9 | 9 |
| Transportation volumes, primarily refined products and petrochemicals (MBPD) | 806 | 818 | 882 |
| Total, net: | | | |
| NGL, crude oil, refined products and petrochemical transportation volumes (MBPD) | 3,990 | 3,704 | 3,574 |
| Natural gas transportation volumes (BBtus/d) | 11,855 | 11,020 | 10,106 |
| Equivalent transportation volumes (MBPD) (1) | 7,110 | 6,604 | 6,233 |

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

Comparison of Results of Operations

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

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2009 | 2008 | 2007 |
| Revenues | $25,510.9 | $35,469.6 | $26,713.8 |
| Operating costs and expenses | 23,565.8 | 33,618.9 | 25,402.1 |
| General and administrative costs | 172.3 | 137.2 | 127.2 |
| Equity in income of unconsolidated affiliates | 51.2 | 34.9 | 10.5 |
| Operating income | 1,824.0 | 1,748.4 | 1,195.0 |
| Interest expense | 641.8 | 540.7 | 413.0 |
| Provision for income taxes | 25.3 | 31.0 | 15.7 |

| | | | |
|---|---|---|---|
| Net income | 1,155.1 | 1,188.9 | 838.0 |
| Net income attributable to noncontrolling interest | 124.2 | 234.9 | 304.4 |
| Net income attributable to Enterprise Products Partners L.P. | 1,030.9 | 954.0 | 533.6 |

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

| | For Year Ended December 31, 2009 | 2008 | 2007 |
|---|---|---|---|
| Gross operating margin by segment: | | | |
| NGL Pipelines & Services | $1,628.7 | $1,325.0 | $848.0 |
| Onshore Natural Gas Pipelines & Services | 501.5 | 589.9 | 493.2 |
| Onshore Crude Oil Pipelines & Services | 164.4 | 132.2 | 109.6 |
| Offshore Pipeline & Services | 180.5 | 187.0 | 171.6 |
| Petrochemical & Refined Products Services | 364.7 | 374.9 | 342.0 |
| Total segment gross operating margin | $2,839.8 | $2,609.0 | $1,964.4 |

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.

The following table summarizes the contribution to revenues from each business segment (including the effects of eliminations and adjustments) during the periods indicated (dollars in millions):

| | For Year Ended December 31, 2009 | 2008 | 2007 |
|---|---|---|---|
| NGL Pipelines & Services: | | | |
| Sales of NGLs | $11,598.9 | $14,573.5 | $11,701.3 |
| Sales of other petroleum and related products | 1.8 | 2.4 | 3.0 |
| Midstream services | 708.3 | 737.9 | 746.4 |
| Total | 12,309.0 | 15,313.8 | 12,450.7 |
| Onshore Natural Gas Pipelines & Services: | | | |
| Sales of natural gas | 2,410.5 | 3,083.1 | 1,676.7 |
| Midstream services | 739.4 | 733.3 | 649.2 |
| Total | 3,149.9 | 3,816.4 | 2,325.9 |
| Onshore Crude Oil Pipelines & Services: | | | |
| Sales of crude oil | 7,110.6 | 12,696.2 | 9,048.5 |
| Midstream services | 80.4 | 67.6 | 55.3 |
| Total | 7,191.0 | 12,763.8 | 9,103.8 |
| Offshore Pipelines & Services: | | | |
| Sales of natural gas | 1.2 | 2.8 | 3.2 |
| Sales of crude oil | 5.3 | 11.1 | 12.1 |
| Midstream services | 333.4 | 254.5 | 208.5 |
| Total | 339.9 | 268.4 | 223.8 |
| Petrochemical & Refined Products Services: | | | |
| Sales of other petroleum and related products | 1,991.8 | 2,757.6 | 2,207.2 |
| Midstream services | 529.3 | 549.6 | 402.4 |
| Total | 2,521.1 | 3,307.2 | 2,609.6 |
| Total consolidated revenues | $25,510.9 | $35,469.6 | $26,713.8 |

Our consolidated revenues are derived from a wide customer base. During 2009, our largest non-affiliated customer based on revenues was Shell, which accounted for 9.8% of our revenues. During 2008 and 2007, our largest non-affiliated customer based on revenues was Valero, which accounted for 11.2% and 8.9%, respectively, of our revenues.

Comparison of 2009 with 2008

Revenues for 2009 were $25.51 billion compared to $35.47 billion for 2008. The $9.96 billion year-to-year decrease in consolidated revenues is primarily due to lower energy commodity sales prices during 2009 relative to 2008. This factor accounted for a $10.01 billion year-to-year decrease in consolidated revenues associated with our NGL, natural gas, crude oil, petrochemical and refined products

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marketing activities. Collectively, the remainder of our consolidated revenues increased $47.9 million year-to-year primarily due to improved results from our offshore activities. Revenues from our Offshore Pipelines & Services business segment for 2009 include aggregate property damage and business interruption insurance proceeds of $31.0 million.

Operating costs and expenses were $23.57 billion for 2009 compared to $33.62 billion for 2008, a $10.05 billion year-to-year decrease. The cost of sales of our marketing activities decreased $9.59 billion year-to-year primarily due to lower energy commodity sales prices. Likewise, the operating costs and expenses of our natural gas processing plants decreased $700.0 million year-to-year primarily due to lower plant thermal reduction ("PTR") costs attributable to the decline in energy commodity prices. Consolidated operating costs and expenses for 2009 include $68.4 million of expenses related to the forfeiture of our interest in TOPS and $66.9 million of expenses related to the settlement of litigation involving TOPS. Collectively, the remainder of our consolidated operating costs and expenses increased $105.1 million year-to-year primarily due to higher depreciation expense and non-cash impairment charges recorded during 2009. General and administrative costs increased $35.1 million year-to-year primarily due to expenses we incurred during 2009 in connection with the TEPPCO Merger.

Changes in our revenues and costs and expenses year-to-year are primarily explained by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $0.85 per gallon during 2009 versus $1.40 per gallon during 2008 – a 39% decrease year-to-year. 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 $3.99 per MMBtu during 2009 versus $9.04 per MMBtu during 2008 – a 56% decrease year-to-year. The market price of crude oil (as measured on the NYMEX) averaged $61.88 per barrel during 2009 compared to $99.73 per barrel during 2008 – a 38% decrease year-to-year. See "Selected Price and Volumetric Data" included within this Item 7 for additional historical energy commodity pricing information.

Equity in income of our unconsolidated affiliates was $51.2 million for 2009 compared to $34.9 million for 2008, a $16.3 million year-to-year increase. Collectively, equity in income from our investments in Cameron Highway and Poseidon increased $13.8 million year-to-year due to higher crude oil transportation volumes. Equity in income from our investments in White River Hub, LLC ("White River Hub") and Skelly-Belvieu increased $3.1 million and $1.9 million year-to-year, respectively. The assets owned by White River Hub began commercial operations in December 2008. We acquired a 49% equity interest in Skelly-Belvieu during December 2008. Equity in income from our Marco Polo platform decreased $13.3 million year-to-year primarily due to the expiration of demand fee revenues during March 2009. The Marco Polo platform is owned through our investment in Deepwater Gateway. Collectively, equity in income of our other investments increased $10.8 million year-to-year largely due to improved results from our investments in south Louisiana.

Operating income for 2009 was $1.82 billion compared to $1.75 billion for 2008. Collectively, the aforementioned changes in revenues, costs and expenses and equity in income of unconsolidated affiliates contributed to the $75.6 million year-to-year increase in operating income.

Interest expense increased to $641.8 million for 2009 from $540.7 million for 2008. The $101.1 million year-to-year increase in interest expense is primarily due to our issuance of Senior Notes M and N in the second quarter of 2008, Senior Notes O in the fourth quarter of 2008 and a $37.6 million decrease in capitalized interest during 2009 relative to 2008. Average debt principal outstanding increased to $11.92 billion during 2009 from $10.17 billion during 2008 primarily due to debt incurred to fund growth capital investments.

Provision for income taxes decreased $5.7 million year-to-year primarily due to lower expenses associated with the Texas Margin Tax, partially offset by a one-time charge of $6.6 million associated with taxable gains arising from

Dixie Pipeline Company's ("Dixie") sale of certain assets during 2009.

As a result of items noted in the previous paragraphs, our consolidated net income decreased $33.8 million year-to-year to $1.16 billion for 2009 compared to $1.19 billion for 2008. Net income attributable to noncontrolling interests was $124.2 million for 2009 compared to $234.9 million for 2008. Such amounts reflect $66.5 million and $193.6 million of net income for 2009 and 2008, respectively, attributable to former owners of TEPPCO. Net income attributable to Enterprise Products Partners increased $76.9 million year-to-year to $1.03 billion for 2009 compared to $954.0 million for 2008.

In general, Hurricanes Gustav and Ike had an adverse effect across our operations in the Gulf of Mexico and along the U.S. Gulf Coast during 2008. Storm-related disruptions in natural gas, NGL and crude oil production in these regions resulted in reduced volumes available to our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which in turn caused a decrease in gross operating margin for certain operations. In addition, property damage caused by Hurricanes Gustav and Ike resulted in lower revenues due to facility downtime as well as higher operating costs and expenses at certain of our plants and pipelines. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, gross operating margin for 2008 includes $49.1 million of repair expenses for property damage sustained by our assets as a result of the hurricanes.

We estimate that gross operating margin was reduced by approximately $81.0 million during 2008 due to the effects of Hurricanes Gustav and Ike as a result of supply interruptions and facility downtime. For more information regarding our insurance program and claims related to these storms, see Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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 $1.63 billion for 2009 compared to $1.33 billion for 2008, a $303.7 million year-to-year increase. Results for 2009 include $4.4 million of proceeds from business interruption insurance claims compared to $1.1 million of proceeds for 2008. The following paragraphs provide a discussion of segment results excluding the effect of cash proceeds from business interruption insurance.

Gross operating margin from our natural gas processing and related NGL marketing business was $948.8 million for 2009 compared to $815.3 million for 2008, a $133.5 million year-to-year increase. Equity NGL production increased to 117 MBPD during 2009 from 108 MBPD during 2008. The recently completed Meeker and Pioneer facilities and related hedging program contributed $104.7 million of the year-to-year increase in gross operating margin due to higher volumes and improved processing margins. These Rocky Mountain natural gas processing plants produced 60 MBPD of equity NGLs during 2009 compared to 49 MBPD during 2008. During 2009, we significantly increased the volume of forward sales transactions in connection with our NGL marketing activities resulting in higher sales margins and increased utilization of certain of our pipeline and storage facilities. Our NGL marketing activities contributed $95.7 million of the year-to-year increase in gross operating margin. Collectively, gross operating margin from the remainder of this business decreased $66.9 million year-to-year primarily due to lower NGL sales margins and equity NGL production volumes in Texas and New Mexico.

Gross operating margin from our NGL pipelines and related storage business was $539.5 million for 2009 compared to $397.4 million for 2008, a $142.1 million year-to-year increase. Total NGL transportation volumes increased to 2,196 MBPD during 2009 from 2,021 MBPD during 2008. Gross operating margin from our Mid-America and Seminole Pipeline Systems increased $85.7 million year-to-year due to a $26.4 million benefit in 2009 related to the Mid-America Pipeline System rate case settlement, an increase in the system-wide tariff, higher volumes and lower fuel costs. Gross operating margin from our NGL import/export terminal and related pipeline increased $20.3 million year-to-year primarily due to higher export volumes. Our Mont Belvieu storage complex contributed $14.9 million of the year-to-year increase in gross operating margin due to higher volumes and fees. Collectively, gross operating margin from the remainder of our NGL pipelines and related storage assets increased $21.2 million year-to-year primarily due to improved results from our south Louisiana assets.

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Gross operating margin from our NGL fractionation business was $136.0 million for 2009 compared to $111.2 million for 2008. Gross operating margin from this business increased $24.8 million year-to-year primarily due to lower fuel costs and higher NGL fractionation volumes at our Mont Belvieu and South Louisiana fractionators during 2009 compared to 2008. Fractionation volumes were 461 MBPD during 2009 compared to 441 MBPD during 2008.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $501.5 million for 2009 compared to $589.9 million for 2008, an $88.4 million year-to-year decrease. Our onshore natural gas transportation volumes were 10,435 BBtus/d during 2009 compared to 9,612 BBtus/d during 2008.

Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business was $448.5 million for 2009 compared to $550.5 million for 2008, a $102.0 million year-to-year decrease. Gross operating margin from our San Juan gathering system decreased $106.4 million year-to-year primarily due to lower fees indexed to regional natural gas prices and condensate sales revenues as a result of the year-to-year decrease in commodity prices. Gross operating margin from our Texas Intrastate System decreased $14.4 million year-to-year. Contributions from the Sherman Extension pipeline of our Texas Intrastate System during 2009 were more than offset by a year-to-year increase in operating costs and expenses and lower revenues from the sale of pipeline condensate. Our Jonah gathering system contributed a $17.0 million year-to-year increase in gross operating margin primarily due to higher natural gas gathering volumes. Collectively, gross operating margin from the remainder of the businesses classified within this segment increased $1.8 million year-to-year primarily due to improved results from natural gas marketing during 2009 compared to 2008.

Gross operating margin from our natural gas storage business was $53.0 million for 2009 compared to $39.4 million for 2008. The $13.6 million year-to-year increase in gross operating margin is primarily due to increased storage activity at our Petal natural gas storage facility and improved results at our Wilson facility. We placed an additional natural gas storage cavern in operation during the third quarter of 2008 at our Petal facility, which provided an additional 4.2 Bcf of subscribed capacity.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $164.4 million for 2009 compared to $132.2 million for 2008, a $32.2 million year-to-year increase. Total onshore crude oil transportation volumes were 680 MBPD during 2009 compared to 696 MBPD during 2008. Gross operating margin from crude oil marketing activities increased $36.4 million year-to-year primarily due to higher sales volumes and margins during 2009 relative to 2008. Collectively, gross operating margin from our crude oil terminals in Cushing, Oklahoma and Midland, Texas increased $3.8 million year-to-year primarily due to higher storage revenues and throughput volumes. Gross operating margin from the remainder of the assets within this business segment decreased $8.0 million year-to-year primarily due to lower volumes and higher operating expenses on our South Texas System and lower equity in income from our investment in Seaway. The pipeline assets owned by Seaway experienced lower volumes and average fees during 2009 compared to 2008.

Offshore Pipelines & Services. Gross operating margin from this business segment was $180.5 million for 2009 compared to $187.0 million for 2008, a $6.5 million year-to-year decrease. Results for 2009 include $28.9 million of proceeds from business interruption insurance claims compared to $0.2 million of such proceeds in 2008. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance proceeds.

Gross operating margin from our offshore crude oil pipeline business was a loss of $56.1 million for 2009 versus $35.1 million of earnings for 2008, a $91.2 million year-to-year decrease. Excluding $135.3 million of expenses related to TOPS recorded during 2009, gross operating margin from our offshore crude oil pipelines increased $44.1 million year-to-year primarily due to the start-up of our Shenzi crude oil pipeline in April 2009 and higher transportation volumes on our Poseidon crude oil pipeline. Total offshore crude oil transportation volumes were 308

MBPD during 2009 versus 169 MBPD during 2008.

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Gross operating margin from our offshore natural gas pipeline business was $65.1 million for 2009 compared to $6.9 million for 2008, a $58.2 million year-to-year increase. Offshore natural gas transportation volumes were 1,420 BBtus/d during 2009 versus 1,408 BBtus/d during 2008. Gross operating margin from our Independence Trail pipeline increased $39.8 million year-to-year. Results for 2008 were negatively impacted by expenses and downtime associated with flex joint repairs on the Independence Trail pipeline; whereas, results for 2009 include $8.7 million of insurance proceeds related to the flex joint repairs. Collectively, gross operating margin from our other offshore natural gas pipelines increased $18.4 million year-to-year primarily due to hurricane-related property damage repair expenses during 2008.

Gross operating margin from our offshore platform services business was $142.6 million for 2009 compared to $144.8 million for 2008, a $2.2 million year-to-year decrease. Gross operating margin from our Independence Hub platform increased $12.1 million year-to-year primarily due to an increase in natural gas processing volumes. Our Independence Hub platform experienced reduced volumes and downtime during 2008 in connection with the pipeline flex joint repairs. Collectively, gross operating margin from our other offshore platforms and related assets decreased $14.3 million year-to-year primarily due to lower natural gas and crude oil processing volumes at our Marco Polo platform as a result of prolonged hurricane-related disruptions and the expiration of demand fee revenues at our Marco Polo and Falcon platforms. Our net platform natural gas processing volumes increased to 700 MMcf/d during 2009 compared to 632 MMcf/d during 2008. Our net platform crude oil processing volumes decreased to 12 MBPD during 2009 compared to 15 MBPD during 2008.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was $364.7 million for 2009 compared to $374.9 million for 2008, a $10.2 million year-to-year decrease.

Gross operating margin from octane enhancement was $11.5 million for 2009 compared to a loss of $11.3 million for 2008, a $22.8 million year-to-year increase. Gross operating margin for 2008 was negatively impacted by downtime, reduced volumes and higher operating expenses as a result of operational issues and the effects of Hurricane Ike.

Gross operating margin from propylene fractionation and related activities was $89.6 million for 2009 compared to $87.2 million for 2008. The $2.4 million year-to-year increase in gross operating margin is largely due to higher propylene sales volumes during 2009 relative to 2008. Propylene fractionation volumes increased to 68 MBPD during 2009 from 58 MBPD during 2008.

Gross operating margin from butane isomerization was $76.2 million for 2009 compared to $95.9 million for 2008. The $19.7 million year-to-year decrease in gross operating margin is primarily due to lower proceeds from the sale of plant by-products as a result of lower commodity prices. Butane isomerization volumes increased to 97 MBPD during 2009 from 86 MBPD during 2008.

Gross operating margin from refined products pipelines and related activities was $124.7 million for 2009 compared to $132.9 million for 2008, an $8.2 million year-to-year decrease. Gross operating margin for 2009 includes $28.7 million of expenses to accrue a liability for pipeline transportation deficiency fees owed to a third-party. Gross operating margin from the remainder of this business increased $20.5 primarily due to increased revenue from product sales, lower operating expenses and higher average fees on our Products Pipeline System during 2009 relative to 2008. Transportation volumes on our refined products pipelines were 682 MBPD during 2009 compared to 702 MBPD during 2008.

Gross operating margin from marine transportation and other services was $62.7 million for 2009 compared to $70.2 million for 2008, a $7.5 million year-to-year decrease. Gross operating margin from marine transportation decreased $4.8 million year-to-year due to higher operating expenses and lower day rates during 2009 relative to 2008. These factors more than offset gross operating margin generated by the acquisition of 19 push boats and 28 barges in June

2009. The utilization of our marine services fleet averaged 87% and 93% during 2009 and 2008, respectively. Gross operating margin from the distribution of lubrication oils and specialty chemicals decreased $2.7 million year-to-year primarily due to lower margins from the sale of specialty chemicals and higher operating expense during 2009 compared to 2008.

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Comparison of 2008 with 2007

Revenues for 2008 were $35.47 billion compared to $26.71 billion for 2007. The $8.76 billion year-to-year increase in consolidated revenues is primarily due to higher energy commodity sales volumes and prices during 2008 relative to 2007. These factors accounted for $8.47 billion of the year-to-year increase in consolidated revenues associated with our NGL, natural gas, crude oil, petrochemical and refined products marketing activities. Equity NGLs we produced at our newly constructed Meeker and Pioneer natural gas plants and sold in connection with our NGL marketing activities contributed $731.3 million of the year-to-year increase in marketing activity revenues. Collectively, the remainder of our consolidated revenues increased $281.1 million year-to-year primarily due to newly constructed assets we placed into service and recently acquired businesses, principally our Independence project and the marine transportation businesses.

Operating costs and expenses were $33.62 billion for 2008 versus $25.4 billion for 2007, an $8.22 billion year-to-year increase. The cost of sales of our marketing activities increased $7.11 billion year-to-year primarily due to higher energy commodity sales volumes and prices. Likewise, the operating costs and expenses of our natural gas processing plants increased $300.4 million year-to-year primarily due to higher energy commodity prices. Collectively, the remainder of our consolidated operating costs and expenses increased $808.7 million year-to-year primarily due to assets we constructed and placed into service or acquired since January 1, 2007. General and administrative costs increased $10.0 million year-to-year largely due to our acquisition of marine transportation businesses during 2008.

Changes in our revenues and costs and expenses year-to-year are primarily explained by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.40 per gallon during 2008 versus $1.19 per gallon during 2007. The Henry Hub market price of natural gas averaged $9.04 per MMBtu during 2008 versus $6.86 per MMBtu during 2007. The NYMEX market price of crude oil averaged $99.73 per barrel during 2008 compared to $72.24 per barrel during 2007. See “Selected Price and Volumetric Data” included within this Item 7 for additional historical energy commodity pricing information.

Equity in income of our unconsolidated affiliates was $34.9 million for 2008 compared to $10.5 million for 2007, a $24.4 million year-to-year increase. Equity in income of our investment in Cameron Highway increased $27.6 million year-to-year due to higher transportation volumes and lower interest expense. Equity in income of our investment in Seaway increased $9.1 million year-to-year due to higher transportation fees. A non-cash impairment charge of $7.0 million associated with our investment in Nemo reduced equity in income for 2007. Collectively, equity in income of our other investments decreased $19.3 million year-to-year primarily due to higher repair and maintenance expenses during 2008 relative to 2007 as well as the effects of downtime and reduced volumes attributable to Hurricanes Gustav and Ike.

Operating income for 2008 was $1.75 billion compared to $1.2 billion for 2007. Collectively, the aforementioned changes in revenues, costs and expenses and equity in income of unconsolidated affiliates contributed to the $553.4 million year-to-year increase in operating income.

Interest expense increased to $540.7 million for 2008 from $413.0 million for 2007. The $127.7 million year-to-year increase in interest expense is primarily due to our issuance of senior and junior notes during 2008 and 2007 to fund our capital growth projects and business combinations. Our average debt principal outstanding during 2008 was $10.17 billion compared to $7.82 billion during 2007. Other income for 2007 includes a $59.6 million gain on the sale of our interests in Mont Belvieu Storage Partners, L.P. and its general partner (collectively, “MB Storage”). See Note 9 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our sale of these equity method investments.

Provision for income taxes increased $15.3 million year-to-year primarily due to higher expenses associated with the Texas Margin Tax.  The increase in expenses for the Texas Margin Tax primarily reflects a higher taxable margin in the State of Texas during 2008 relative to 2007.  In addition, we recognized a $5.1 million benefit with respect to the Texas Margin Tax during 2007 due to the reorganization of certain of our entities from partnerships to limited liability companies.

As a result of items noted in the previous paragraphs, our consolidated net income increased $350.9 million year-to-year to $1.19 billion for 2008 compared to $838.0 million for 2007. Net income attributable to noncontrolling interests was $234.9 million for 2008 compared to $304.4 million for 2007. Such amounts reflect $193.6 million and $273.8 million of net income for 2008 and 2007, respectively, attributable to former owners of TEPPCO. Net income attributable to Enterprise Products Partners increased $420.4 million year-to-year to $954.0 million for 2008 compared to $533.6 million for 2007.

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 $1.33 billion for 2008 compared to $848.0 million for 2007. The $477.0 million year-to-year increase in segment gross operating margin is due to strong natural gas processing margins and petrochemical demand for NGLs as well as an increase in equity NGL production attributable to our Meeker and Pioneer natural gas processing facilities. Results for 2007 include $32.7 million of proceeds from business interruption insurance claims compared to $1.1 million of proceeds for 2008. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $815.3 million for 2008 compared to $389.1 million for 2007. Equity NGL production increased to 108 MBPD during 2008 from 88 MBPD during 2007. The $426.2 million year-to-year increase in gross operating margin is largely due to contributions from our Meeker and Pioneer cryogenic natural gas processing facilities, which commenced commercial operations during October 2007 and February 2008, respectively. These facilities contributed $274.5 million of the year-to-year increase in gross operating margin and produced 49 MBPD of equity NGLs during 2008 compared to 23 MBPD during 2007. Collectively, gross operating margin from the remainder of this business increased $151.7 million year-to-year primarily due to improved results from our NGL marketing activities attributable to higher NGL sales margins and volumes in 2008 relative to 2007. Results for 2008 include $6.8 million of hurricane-related property damage repair expenses associated with our natural gas processing plants in south Louisiana.

Gross operating margin from our NGL pipelines and related storage business was $397.4 million for 2008 compared to $331.1 million for 2007, a $66.3 million year-to-year increase. Total NGL transportation volumes increased to 2,021 MBPD during 2008 from 1,877 MBPD during 2007. Gross operating margin from our Mid-America and Seminole Pipeline Systems increased $43.6 million year-to-year due to higher transportation volumes and an increase in the system-wide tariff. These pipeline systems contributed 116 MBPD of the year-to-year increase in NGL transportation volumes. Gross operating margin from our Mont Belvieu storage complex increased $15.5 million as a result of higher storage revenues during 2008 relative to 2007. Collectively, gross operating margin from the remainder of our NGL pipelines and storage business increased $7.2 million year-to-year attributable to higher transportation volumes on our Dixie and Lou-Tex NGL Pipeline Systems and lower maintenance and pipeline integrity expenses on our Dixie and South Louisiana Pipeline Systems. In general, the improved results from our NGL pipeline and storage assets were partially offset by downtime and reduced volumes as a result of Hurricanes Gustav and Ike during 2008. Results for 2008 include $0.9 million of hurricane-related property damage repair expenses.

Gross operating margin from our NGL fractionation business was $111.2 million for 2008 compared to $95.1 million for 2007, a $16.1 million year-to-year increase. Fractionation volumes increased from 405 MBPD during 2007 to 441 MBPD during 2008. The increase in gross operating margin and fractionation volumes is primarily due to our Hobbs fractionator, which we placed into service during August 2007. Results for 2008 include $0.9 million of hurricane-related property damage repair expenses.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $589.9 million for 2008 compared to $493.2 million for 2007, a $96.7 million year-to-year increase. Our onshore natural gas transportation volumes were 9,612 BBtus/d during 2008 compared to 8,465 BBtus/d during 2007. Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business increased to $550.5 million for 2008 from $464.8 million for 2007. The $85.7 million year-to-year increase in gross operating margin is primarily due to (i) higher revenues from our San Juan Gathering System, (ii) higher transportation activity on our Texas Intrastate System, (iii) higher natural gas sales margins on our Acadian Gas System, and (iv) an increase in gathering volumes on our Jonah System as a result of system expansion projects. Results for 2008 include $1.3 million of hurricane-related property damage repair expenses attributable to Hurricanes Gustav and Ike.

Gross operating margin from our natural gas storage business was $39.4 million for 2008 compared to $28.4 million for 2007. The $11.0 million year-to-year increase in gross operating margin is primarily due to increased storage activity at our Petal natural gas storage facility and improved results at our Wilson facility. We placed additional natural gas storage caverns in operation during the third quarters of 2007 and 2008 at our Petal facility, which provided an additional 1.6 Bcf and 4.2 Bcf of subscribed capacity, respectively.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $132.2 million for 2008 compared to $109.6 million for 2007. Total onshore crude oil transportation volumes were 696 MBPD during 2008 compared to 652 MBPD during 2007. The $22.6 million year-to-year increase in segment gross operating margin is primarily due to an increase in crude oil transportation volumes and fees during 2008 relative to 2007. Completion of system expansions in south and west Texas contributed 42 MBPD of the year-to-year increase in crude oil transportation volumes. Average transportation fees on the pipeline system owned by Seaway were higher during 2008 compared to 2007 as a result of an increase in volumes transported on a spot basis and higher long-haul volumes, both of which are subject to higher tariffs.

Offshore Pipelines & Services. Gross operating margin from this business segment was $187.0 million for 2008 compared to $171.6 million for 2007, a $15.4 million year-to-year increase. Results for 2008 include $0.2 million of proceeds from business interruption insurance claims compared to $3.4 million of proceeds during 2007. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance.

Gross operating margin from our offshore platform services business was $144.8 million for 2008 compared to $111.7 million for 2007, a $33.1 million year-to-year increase. Our Independence Hub platform, which was completed in March 2007, provided a $49.5 million year-to-year increase in gross operating margin. Gross operating margin increased year-to-year despite the platform being shut-in for 66 days during the second quarter of 2008 due to a leak on the Independence Trail export pipeline. While the Independence Hub platform did not earn volumetric fees during the period of suspended operations, the platform continued to earn its fixed demand revenues of approximately $4.6 million per month. Gross operating margin from the remainder of this business decreased $16.4 million year-to-year primarily due to the effects of Hurricanes Gustav and Ike and upstream supply disruptions. Results for our offshore platform services business include $5.0 million of hurricane-related property damage repair expenses in 2008. Our net platform natural gas processing volumes increased to 632 MMcf/d during 2008 compared to 494 MMcf/d during 2007.

Gross operating margin from our offshore crude oil pipeline business was $35.1 million for 2008 versus $21.1 million for 2007, a $14.0 million year-to-year increase. Gross operating margin increased $27.6 million year-to-year due to increased equity in income of Cameron Highway, which benefited from higher crude oil transportation volumes and no interest expense in 2008 relative to 2007. Net to our ownership interest, crude oil transportation volumes on the Cameron Highway Oil Pipeline System were 80 MBPD in 2008 compared to 44 MBPD in 2007. Gross operating margin from the remainder of this business decreased $13.6 million year-to-year due to the effects of Hurricanes

Gustav and Ike, which include (i) downtime resulting from damage sustained by our pipelines as well as downstream assets owned by third-parties and (ii) reduced volumes available to our pipelines as a result of upstream supply disruptions. Results for our offshore crude oil pipeline business include $2.3 million of hurricane-related property damage repair expenses in 2008. Total offshore crude oil transportation volumes were 169 MBPD during 2008 versus 163 MBPD during 2007.

Gross operating margin from our offshore natural gas pipeline business was $6.9 million for 2008 compared to $35.4 million for 2007, a $28.5 million year-to-year decrease. Offshore natural gas transportation volumes were 1,408 BBtus/d during 2008 versus 1,641 BBtus/d during 2007. Gross operating margin from our Independence Trail pipeline, which first received production in July 2007, increased $28.4 million year-to-year on a 241 BBtus/d increase in transportation volumes. Collectively, gross operating margin from our other offshore natural gas pipelines decreased $56.9 million year-to-year primarily due to the effects of Hurricanes Gustav and Ike. Results for 2008 include $29.9 million of hurricane-related property damage repair expenses.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was $374.9 million for 2008 compared to $342.0 million for 2007.

Gross operating margin from propylene fractionation and related activities was $87.2 million for 2008 compared to $66.3 million for 2007. The $20.9 million year-to-year increase in gross operating margin is largely due to higher propylene sales margins during 2008 relative to 2007. Results for our propylene fractionation and related pipeline business for 2008 include $0.8 million of hurricane-related property damage repair expenses.

Gross operating margin from butane isomerization was $95.9 million for 2008 compared to $91.4 million for 2007. The $4.5 million year-to-year increase in gross operating margin is primarily due to strong demand for high-purity isobutane and increased by-product sales revenues as a result of higher NGL prices during 2008 relative to 2007. Butane isomerization volumes decreased to 86 MBPD during 2008 compared to 90 MBPD during 2007 due to production interruptions resulting from Hurricane Ike and operational issues at our octane enhancement facility during 2008. Gross operating margin from octane enhancement was a loss of $11.3 million for 2008 compared to $18.3 million of earnings for 2007. The $29.6 million year-to-year decrease in gross operating margin is primarily due to downtime, reduced volumes and higher operating expenses as a result of operational issues during 2008 and the effects of Hurricane Ike.

Gross operating margin from refined products pipelines and related activities was $132.9 million for 2008 compared to $162.7 million for 2007. The $29.8 million year-to-year decrease in gross operating margin is primarily due to higher expenses on our Products Pipeline System during 2008 relative to 2007 for storage tank and pipeline maintenance and the effects of lower transportation volumes during 2008. Transportation volumes on our refined products pipelines decreased to 702 MBPD during 2008 from 768 MBPD during 2007 due in part to the effects of Hurricanes Gustav and Ike. Results for 2008 include $0.9 million of hurricane-related property damage repair expenses.

Gross operating margin from marine transportation and other services was $70.2 million for 2008 compared to $3.3 million for 2007. The $66.9 million year-to-year increase in gross operating margin is primarily attributable to the marine transportation businesses we acquired during 2008 from Cenac and Horizon. At December 31, 2008, our fleet of marine vessels consisted of 51 tow boats and 113 barges. The utilization of our marine services fleet averaged 93% during 2008.

Liquidity and Capital Resources

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business combinations and distributions to partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and revolving credit arrangements. Capital expenditures for long-term needs resulting from business expansion projects and acquisitions are expected to be funded by a variety of sources (either separately or in combination) including operating cash flows, borrowings under credit facilities, the issuance of additional equity and debt securities and proceeds from divestitures of ownership interests in assets to affiliates or third parties. 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.

At December 31, 2009, we had $54.7 million of unrestricted cash on hand and approximately $1.66 billion of available credit under our revolving credit facilities, which includes the available borrowing capacity of our consolidated subsidiaries such as Duncan Energy Partners. We had approximately $11.3 billion in principal outstanding under consolidated debt agreements at December 31, 2009. In total, our consolidated liquidity at December 31, 2009 was approximately $1.72 billion.

Registration Statements

We may issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. Duncan Energy Partners may do likewise in meeting its liquidity and capital spending requirements. We have a universal shelf registration statement on file with the SEC that would allow us to issue an unlimited amount of debt and equity securities for general partnership purposes.

The following tables present information regarding equity and debt offerings made under our universal shelf registration statement since January 1, 2009 through the date of this filing. In addition, an exchange offer we made in connection with the TEPPCO Merger for certain TEPPCO notes was completed under a Form S-4 registration statement in October 2009. Dollar amounts presented in the tables are in millions, except offering price amounts.

| Underwritten Equity Offering | Number of Common Units Issued | Offering Price | Net Cash Proceeds (1) |
|---|---|---|---|
| January 2009 underwritten offering | 10,590,000 | $22.20 | $225.6 |
| September 2009 underwritten offering | 8,337,500 | 28.00 | 226.4 |
| January 2010 underwritten offering | 10,925,000 | 32.42 | 343.1 |
| Total | 29,852,500 | | $795.1 |

(1) Net cash proceeds from these equity offerings were used to temporarily reduce borrowings outstanding under EPO’s Multi-Year Revolving Credit Facility and for general partnership purposes.

| Note Series | Issued | Principal Amount |
|---|---|---|
| Senior Notes P (1) | June 2009 | $500.0 |
| Senior Notes Q & R (2) | October 2009 | 1,100.0 |
| Senior Notes S - W (3) | October 2009 | 1,659.9 |
| Junior Subordinated Notes C (3) | October 2009 | 285.8 |
| Total | | $3,545.7 |

(1) Net proceeds from this senior note offering were used to repay a $200.0 million term loan, temporarily reduce borrowings outstanding under EPO’s Multi-Year Revolving Credit Facility and for general partnership purposes.
(2) Net proceeds from these senior note offerings were used to repay $500.0 million in aggregate principal amount of Senior Notes F that matured in October 2009, temporarily reduce borrowings outstanding under EPO’s Multi-Year Revolving Credit Facility and for general partnership purposes.
(3) In connection with the TEPPCO Merger, substantially all of TEPPCO’s notes were exchanged for a corresponding series of new EPO notes. The EPO notes issued in the exchange were recorded at the same carrying value as the TEPPCO notes being replaced. These notes were issued under a Form S-4 registration statement.

During 2008, Duncan Energy Partners filed a universal shelf registration statement with the SEC that allows it to issue up to $1 billion of debt and equity securities.  In 2009, Duncan Energy Partners completed an offering of 8,943,400 of its common units, which generated net cash proceeds of approximately $137.4 million.  Duncan Energy Partners used the aggregate net cash proceeds from this

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offering to repurchase an equal number of its common units that were beneficially owned by EPO. Duncan Energy Partners subsequently cancelled the common units it repurchased from EPO. At December 31, 2009, Duncan Energy Partners can issue approximately $856.4 million of additional equity or debt securities under its registration statement.

We have filed registration statements with the SEC authorizing the issuance of up to an aggregate 40,000,000 common units in connection with our distribution reinvestment plan ("DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units of our partnership. During the year ended December 31, 2009, we issued 11,909,083 common units in connection with our DRIP, which generated proceeds of $286.2 million from plan participants. Affiliates of EPCO reinvested $246.3 million in connection with the DRIP during the year ended December 31, 2009.

In addition, we have a registration statement on file related to our employee unit purchase plan, under which we can issue up to 1,200,000 common units. Under this plan, employees of EPCO can purchase our common units at a 10% discount through payroll deductions. During the year ended December 31, 2009, we issued 180,837 common units to employees under this plan, which generated proceeds of $4.6 million.

For information regarding our public debt obligations or partnership equity, see Notes 12 and 13, respectively, of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Letter of Credit Facilities

At December 31, 2009, EPO had outstanding a $50.0 million letter of credit related to its commodity derivative instruments and a $58.3 million letter of credit related to its Petal GO Zone Bonds. These letter of credit facilities do not reduce the amount available for borrowing under EPO's credit facilities.

Credit Ratings

At March 1, 2010, the investment-grade credit ratings of EPO's senior unsecured debt securities remain unchanged from December 31, 2009 at Baa3 by Moody's Investor Services; BBB- by Fitch Ratings; and BBB- by Standard and Poor's. Such ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any security. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it determines that the circumstances warrant such a change and should be evaluated independently of any other rating.

Based on the characteristics of the $1.53 billion of fixed/floating unsecured junior subordinated notes, the rating agencies assigned partial equity treatment to the notes. Moody's Investor Services and Standard and Poor's each assigned 50% equity treatment and Fitch Ratings assigned 75% equity treatment.

A downgrade of our credit ratings could result in our being required to post financial collateral up to the amount of our guaranty of indebtedness of our Centennial joint venture, which was $60.0 million at December 31, 2009. Furthermore, from time to time we enter into contracts in connection with our commodity and interest rate hedging activities that may require the posting of financial collateral, which may be substantial, if our credit were to be downgraded below investment grade.

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Cash Flows from Operating, Investing and Financing Activities

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

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2009 | 2008 | 2007 |
| Net cash flows provided by operating activities | $2,377.2 | $1,567.1 | $1,953.6 |
| Cash used in investing activities | 1,546.9 | 3,246.9 | 2,871.8 |
| Cash provided by (used in) financing activities | (837.1 ) | 1,690.7 | 946.3 |

Net cash flows provided by operating activities are largely dependent on earnings from our business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide services for producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; as feedstock 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 "Risk Factors" under Item 1A of this annual report.

Our Statements of Consolidated Cash Flows are prepared using the indirect method. The indirect method derives net cash flows from operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and similar transactions, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, (iii) other non-cash amounts such as depreciation, amortization, operating lease expenses paid by EPCO, changes in the fair market value of derivative instruments and equity in earnings from unconsolidated affiliates (net cash flows provided by operating activities reflect the actual cash distributions we receive from such investees), and (iv) the effects of all items classified as investing or financing cash flows, such as proceeds from asset sales and related transactions or extinguishment of debt.

In general, the net effect of changes in operating accounts results from the timing of cash receipts from sales and cash payments for purchases and other expenses during each period. Increases or decreases in inventory are influenced by the quantity of products held in connection with our marketing activities and changes in energy commodity prices.

Cash used in investing activities primarily represents expenditures for additions to property, plant and equipment, business combinations and investments in unconsolidated affiliates. Cash provided by financing activities generally consists of borrowings and repayments of debt, distributions to partners and proceeds from the issuance of equity securities. Amounts presented in our Statements of Consolidated Cash Flows for borrowings and repayments under debt agreements are influenced by the magnitude of cash receipts and payments under our revolving credit facilities.

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The following information highlights the significant year-to-year variances in our cash flow amounts:

Comparison of 2009 with 2008

Operating Activities. The $810.1 million increase in net cash flows provided by operating activities was primarily due to the following:

§ Net cash flows from consolidated operations (excluding distributions received from unconsolidated affiliates, cash payments for interest and cash payments for income taxes) increased $908.8 million year-to-year. The increase in operating cash flow is generally due to increased profitability and the timing of related cash receipts and disbursements. The total year-to-year increase also reflects a $68.9 million increase in operating cash proceeds we received from insurance claims related to certain named storms. For information regarding cash proceeds from business interruption and property damage claims, see Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

§ Cash payments for interest increased $81.8 million year-to-year primarily due to increased borrowings to finance our capital spending program. Our average debt principal outstanding for 2009 was $11.92 billion compared to $10.17 billion for 2008.

§ Cash payments for income taxes increased $22.7 million year-to-year primarily due to higher payments made for the Texas Margin tax and a taxable gain incurred in 2009 arising from Dixie's sale of certain assets.

Investing Activities. The $1.7 billion decrease in cash used for investing activities was primarily due to the following:

§ Capital spending for property, plant and equipment, net of contributions in aid of construction costs, decreased $945.9 million year-to-year. For additional information related to our capital spending program, see "Liquidity and Capital Resources – Capital Spending" included within this Item 7.

§ Cash used for business combinations decreased $446.2 million year-to-year. Our 2009 business combinations primarily consisted of the acquisition of certain rail and truck terminal facilities located in Mont Belvieu, Texas, a pipeline system in Texas, and the acquisition of tow boats and tank barges primarily based in Miami, Florida, with additional assets located in Mobile, Alabama and Houston, Texas. In 2008, our most significant business combinations consisted of our acquisition of marine transportation businesses. In addition, during 2008 we acquired 100% of the membership interest in Great Divide Gathering LLC ("Great Divide") and additional interests in consolidated subsidiaries. For additional information regarding our business combinations, see Note 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

§ Restricted cash related to our hedging activities decreased $140.2 million (a cash inflow) during 2009 primarily due to the reduction of margin requirements related to derivative instruments we utilized. For 2008, restricted cash related to our hedging activities increased $132.8 million (a cash outflow). See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our interest rate and commodity risk hedging portfolios.

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Financing Activities. Cash used in financing activities was $837.1 million for 2009 compared to cash provided by financing activities of $1,690.7 million in 2008. The $2.53 billion change in financing activities was primarily due to the following:

§ Net repayments under our consolidated debt agreements of $276.9 million in 2009 compared to net borrowings under our consolidated debt agreements of $2.75 billion in 2008. During 2008, EPO and TEPPCO issued a combined $2.6 billion in principal amount of senior notes. 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.

§ Cash distributions paid to our partners increased $217.4 million year-to-year primarily due to increases in our common units outstanding and quarterly distribution rates.

§ Distributions paid to noncontrolling interests decreased $43.9 million year-to-year primarily due to the cessation of TEPPCO's cash distributions following the TEPPCO Merger.

§ Net cash proceeds from the issuance of our common units increased $769.9 million year-to-year due to underwritten and private equity offerings in 2009 along with increased participation in our DRIP.

§ Contributions from noncontrolling interests decreased $172.8 million year-to-year primarily due to the $137.4 million of net cash proceeds that Duncan Energy Partners received from the issuance of its common units in June and July 2009 compared to net cash proceeds of $271.3 million received from unit offerings of TEPPCO during 2008.

Comparison of 2008 with 2007

Operating Activities. The $386.5 million decrease in net cash flows provided by operating activities was primarily due to the following:

§ Net cash flows from consolidated operations (excluding distributions received from unconsolidated affiliates and cash payments for interest) decreased $240.1 million year-to-year. Although our gross operating margin increased year-to-year (see "Results of Operations" within this Item 7), the reduction in operating cash flow is generally due to the timing of related cash receipts and disbursements. The $240.1 million total year-to-year decrease also reflects a $127.3 million decrease in cash proceeds we received from insurance claims related to certain named storms. For information regarding cash proceeds from business interruption and property damage claims, see Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

§ Cash payments for interest increased $140.2 million year-to-year primarily due to increased borrowings to finance our capital spending program. Our average debt balance for 2008 was $10.17 billion compared to $7.82 billion for 2007.

Investing Activities. The $375.1 million increase in cash used for investing activities was primarily due to the following:

§ Cash used for business combinations increased $517.5 million year-to-year, primarily due to approximately $346.0 million in business combinations related to our marine transportation businesses. In addition, during 2008 we acquired 100% of the membership interest in Great Divide and additional interest in consolidated subsidiaries.

§

Capital spending for property, plant and equipment, net of contributions in aid of construction costs, decreased $194.0 million year-to-year. For additional information related to our capital spending program, see "Liquidity and Capital Resources – Capital Spending" included within this Item 7.

§ Proceeds from the sale of assets and related transactions decreased $146.9 million year-to-year primarily due to the sale of certain equity interests and related storage assets located in Mont Belvieu, Texas during 2007.

§ Cash outlays for investments in unconsolidated affiliates decreased by $172.1 million year-to-year. Expenditures for 2007 include the $216.5 million we contributed to Cameron Highway during the second quarter of 2007. Cameron Highway used these funds, along with an equal contribution from our 50% joint venture partner in Cameron Highway, to repay approximately $430.0 million of its outstanding debt. Expenditures for 2008 include (i) $22.5 million in contributions to White River Hub, (ii) $11.1 million in contributions to Centennial and (iii) $36.0 million to acquire a 49% interest in Skelly-Belvieu.

§ An $85.5 million increase in restricted cash (a cash outflow) due to margin requirements related to our hedging activities. See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our interest rate and commodity risk hedging portfolios.

Financing Activities. The $744.4 million increase in cash provided by financing activities was primarily due to the following:

§ Net borrowings under our consolidated debt agreements increased $923.8 million year-to-year. During 2008, we and TEPPCO issued a combined $2.6 billion in principal amount of senior notes. 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.

§ Net cash proceeds from the issuance of our common units increased $73.6 million year-to-year due to increased participation in our DRIP.

§ Cash distributions paid to our partners increased $79.7 million year-to-year primarily due to increases in our common units outstanding and quarterly distribution rates.

§ Distributions paid to noncontrolling interests increased $57.1 million year-to-year primarily due to increases in the quarterly distribution rates of Duncan Energy Partners and TEPPCO, along with an increase in TEPPCO's units outstanding.

§ The early termination and settlement of interest rate hedging derivative instruments during 2008 resulted in net cash payments of $66.5 million compared to net cash receipts of $49.1 million during the same period in 2007, which resulted in a $115.6 million decrease in financing cash flows between years.

Capital Spending

An integral part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. We believe that we are positioned to continue to grow our system of assets through the construction of new facilities and to capitalize on expected increases in natural gas and/or crude oil production from resource basins in the Rocky Mountains, Midcontinent, Northeast and U.S. Gulf Coast regions, including the Barnett Shale, Haynesville Shale, Eagle Ford Shale, Marcellus Shale and deepwater Gulf of Mexico producing regions.

Management continues to analyze potential acquisitions, 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 forecast that 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 by activity for the periods indicated (dollars in millions):

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2009 | 2008 | 2007 |
| Capital spending for business combinations: | | | |
| Great Divide Gathering System acquisition | $-- | $125.2 | $-- |
| South Monco Pipeline System acquisition | 0.8 | -- | 35.0 |
| Cenac and Horizon acquisitions | -- | 345.7 | -- |
| Other business combinations | 106.5 | 82.6 | 0.9 |
| Total | 107.3 | 553.5 | 35.9 |
| Capital spending for property, plant and equipment, net: (1) | | | |
| Growth capital projects (2) | 1,373.9 | 2,249.5 | 2,464.7 |
| Sustaining capital projects (3) | 192.6 | 262.9 | 241.7 |
| Total | 1,566.5 | 2,512.4 | 2,706.4 |
| Capital spending for intangible assets: | | | |
| Acquisition of intangible assets | 1.4 | 5.8 | 14.5 |
| Capital spending attributable to unconsolidated affiliates: | | | |
| Investments in unconsolidated affiliates | 18.8 | 64.7 | 236.8 |
| Total capital spending | $1,694.0 | $3,136.4 | $2,993.6 |

(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 $17.8 million, $27.2 million and $57.6 million for the years ended December 31, 2009, 2008 and 2007, respectively.
(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.

Based on information currently available, we estimate our consolidated capital spending for 2010 will approximate $1.75 billion, which includes estimated expenditures of $1.5 billion for growth capital projects and acquisitions and $250.0 million for sustaining capital expenditures.

Our forecast of consolidated capital expenditures is based on our current announced strategic operating and growth plans, which are dependent upon our ability to generate the required funds from either operating cash flows or from other means, including borrowings under debt agreements, issuance of equity, and potential divestitures of certain assets to third and/or related parties. Our forecast of capital expenditures may change due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast may change as a result of decisions made by management at a later date, which may include acquisitions or decisions to take on additional partners.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be a principal factor that determines how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future operating growth needs, and although we currently intend to make the forecasted expenditures discussed above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

At December 31, 2009, we had approximately $497.5 million in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction at our Mont Belvieu complex and our Barnett Shale, Haynesville Shale and Piceance Basin natural gas pipeline projects.

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Pipeline Integrity Costs

Our NGL, crude oil, refined products, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the DOT. This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (which include 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.

In April 2002, a subsidiary of ours acquired several midstream energy assets located in Texas and New Mexico from El Paso Corporation ("El Paso"). These assets included the Texas Intrastate System and the Carlsbad Gathering Systems. With respect to such assets, El Paso agreed to indemnify our subsidiary for any pipeline integrity costs it incurred (whether paid or payable) for five years following the acquisition date. The indemnity provisions did not take effect until such costs exceeded $3.3 million annually; however, the amount reimbursable by El Paso was capped at $50.2 million in the aggregate. In 2007, we recovered $31.1 million from El Paso related to our 2006 expenditures. During 2007, we received a final amount of $5.4 million from El Paso related to this indemnity.

The following table summarizes our pipeline integrity costs, net of indemnity payments from El Paso, for the periods indicated (dollars in millions):

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2009 | 2008 | 2007 |
| Expensed | $44.9 | $55.4 | $51.9 |
| Capitalized | 37.7 | 86.2 | 78.9 |
| Total | $82.6 | $141.6 | $130.8 |

We expect our cash outlay for the pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $116.3 million in 2010.

Critical Accounting Policies and Estimates

In our financial reporting process, 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 during the 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 the assets. Our estimate of depreciation incorporates 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:

- changes in laws and regulations that limit the estimated economic life of an asset;
- changes in technology that render an asset obsolete;
- changes in expected salvage values; or

§ changes in the forecast life of applicable resource basins, if any.

At December 31, 2009 and 2008, the net book value of our property, plant and equipment was $17.69 billion and $16.73 billion, respectively. We recorded $678.1 million, $595.9 million and $515.7 million in depreciation expense for the years ended December 31, 2009, 2008 and 2007, respectively.

For additional information regarding our property, plant and equipment, see Notes 2 and 8 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Measuring Recoverability of Long-Lived Assets and Equity Method Investments

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) 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. Long-lived assets with carrying values that are not expected to be recovered through forecast future cash flows are written down to their estimated fair values. 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. Our estimates of such 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. An impairment charge would be recorded for the excess of a long-lived asset's carrying value over its estimated fair value, which is based on a series of assumptions similar to those used to derive undiscounted cash flows. Those assumptions also include usage of probabilities for a range of possible outcomes, market values and replacement cost estimates.

An equity method investment is evaluated for impairment whenever events or changes in circumstances indicate that there is a possible loss in value of the investment 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. Equity method investments with carrying values that are not expected to be recovered through expected future cash flows are written down to their estimated fair values. 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. This estimate of discounted cash flows is 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. A significant change in these underlying assumptions could result in our recording an impairment charge.

During 2009, we recognized non-cash asset impairment charges related to property, plant and equipment of $29.4 million, which is reflected as a component of operating costs and expenses. No such asset impairment charges were recorded in 2008 or 2007.

During 2007, we evaluated our equity method investment in Nemo for impairment. As a result of this evaluation, we recorded a $7.0 million non-cash impairment charge that is a component of equity in earnings from unconsolidated affiliates for the year ended December 31, 2007. During 2009 and 2008 there were no such impairment charges.

For additional information regarding impairment charges associated with our long-lived assets and equity method investments, see Notes 6 and 9 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Amortization Methods and Estimated Useful Lives of Qualifying Intangible Assets

The specific, identifiable intangible assets of a business enterprise depend largely upon the nature of its operations. Potential intangible assets include intellectual property, such as technology, patents, trademarks and trade names, customer contracts and relationships, and non-compete agreements, as well as other intangible assets. The method used to value each intangible asset will vary depending upon a number

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of factors, including the nature of the asset and the economic returns it is generating or is expected to generate.

Our customer relationship intangible assets primarily represent customer bases we acquired in connection with business combinations. The value we assigned to these customer relationships is being amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying oil and natural gas resource bases from which the customers produce are estimated to be consumed or otherwise used. Our estimate of the useful life of each resource base 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 the rights we own arising from discrete contractual agreements, such as the long-term rights we possess under the Shell natural gas processing agreement or the natural gas transportation contracts of our Val Verde and Jonah systems. A contract-based intangible asset with a finite life is amortized over its estimated useful life (or term), which is the period over which the asset is expected to contribute directly or indirectly to the cash flows of an entity. Our estimates of useful life are based on a number of factors, including:

§ the expected useful life of the related tangible assets (e.g., fractionation facility, pipeline or other asset);

§ any legal or regulatory developments that would impact such contractual rights; and

§ any contractual provisions that enable us to renew or extend such agreements.

If our underlying assumptions regarding the estimated useful life of an intangible asset 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 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, 2009 and 2008, the carrying value of our intangible asset portfolio was $1.06 billion and $1.18 billion, respectively. We recorded $119.9 million, $130.0 million and $125.2 million in amortization expense associated with our intangible assets for the years ended December 31, 2009, 2008 and 2007, respectively.

For additional information regarding our intangible assets, see Notes 2 and 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 prices we paid for certain businesses over their respective fair values. We do not amortize goodwill; however, we test our goodwill for impairment at the beginning of each fiscal year, and more frequently, if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. Our goodwill testing involves the determination of a reporting unit's fair value, which is predicated on our assumptions regarding the future economic prospects of the reporting unit.

Such assumptions include:

§ discrete financial forecasts for the assets classified within the reporting unit, which rely on management's estimates of operating margins and transportation volumes;

§ long-term growth rates for cash flows beyond the discrete forecast period; and

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§ appropriate discount rates.

If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings is required to reduce the carrying value of the goodwill to its implied fair value. Based on our most recent goodwill impairment testing, each reporting unit's fair value was substantially in excess (a minimum of 10%) of its carrying value.

At December 31, 2009 and 2008, the carrying value of our goodwill was $2.02 billion. We recorded goodwill impairment charges of $1.3 million during 2009. No such impairment charges were recorded in 2008 or 2007. For additional information regarding our goodwill, see Notes 2 and 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our 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:

§ persuasive evidence of an exchange arrangement exists;

§ delivery has occurred or services have been rendered;

§ the buyer's price is fixed or determinable; and

§ collectability 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 such 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 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.

Reserves for Environmental Matters

Our business activities are subject to various federal, state and local laws and regulations governing environmental quality and pollution control. Such laws and regulations may, in certain instances, require us to remediate current or former operating sites where specified substances have been released or disposed of. We accrue reserves for environmental matters when our assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Our assessments are based on studies, as well as site surveys, to determine the extent of any environmental damage and the necessary requirements to remediate this damage. Future environmental developments, such as increasingly strict environmental laws and additional claims for damages to property, employees and other persons

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resulting from current or past operations, could result in substantial additional costs beyond our current reserves. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2009, none of our estimated environmental remediation liabilities were discounted to present value since the ultimate amount and timing of cash payments for such liabilities were not readily determinable.

At December 31, 2009 and 2008, we had a liability for environmental remediation of $16.7 million and $22.3 million, respectively, which was derived from a range of reasonable estimates based upon studies and site surveys. We have recorded our best estimate of the cost of remediation activities. See Notes 2 and 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding environmental matters.

Natural Gas Imbalances

In the natural gas pipeline transportation business, imbalances frequently result from differences in natural gas volumes received from and delivered to our customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. The vast majority of our settlements are through in-kind arrangements whereby incremental volumes are delivered to a customer (in the case of an imbalance payable) or received from a customer (in the case of an imbalance receivable). Such in-kind deliveries are ongoing and take place over several months. In some cases, settlements of imbalances accumulated over a period of time are ultimately cashed out and are generally negotiated at values which approximate average market prices over a period of time. As a result, for gas imbalances that are ultimately settled over future periods, we estimate the value of such current assets and liabilities using average market prices, which we believe is representative of the value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

The following table presents our natural gas imbalance receivables/payables at the dates indicated:

| | December 31, | |
|---|---|---|
| | 2009 | 2008 |
| Natural gas imbalance receivables (1) | $24.1 | $63.4 |
| Natural gas imbalance payables (2) | 19.0 | 50.8 |

(1) Reflected as a component of “Accounts and notes receivable – trade” on our Consolidated Balance Sheets included under Item 8 of this annual report.
(2) Reflected as a component of “Accrued product payables” on our Consolidated Balance Sheets included under Item 8 of this annual report.

Other Items

Duncan Energy Partners

For information regarding our relationship with Duncan Energy Partners, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Insurance Matters

We participate as a named insured in EPCO’s insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which are customary and sufficient for the nature and extent of our operations. In light of recent hurricane and other weather-related events, the renewal of policies for weather-related risks resulted in significant increases in premiums and certain deductibles, as well as changes in the scope of coverage.  For additional information regarding insurance matters, see Note 19 of the Notes Consolidated Financial Statements included under Item 8 of this annual report.

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Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2009 (dollars in millions).

| Contractual Obligations | Total | Payment or Settlement due by Period Less than 1 year | 1-3 years | 4-5 years | More than 5 years |
|---|---|---|---|---|---|
| Scheduled maturities of long-term debt (1) | $ 11,297.0 | $ 554.0 | $ 2,102.8 | $ 2,350.0 | $ 6,290.2 |
| Estimated cash payments for interest (2) | 12,372.2 | 667.4 | 1,190.2 | 939.4 | 9,575.2 |
| Operating lease obligations (3) | 343.9 | 37.6 | 68.0 | 48.8 | 189.5 |
| Purchase obligations: (4) | | | | | |
| Product purchase commitments: | | | | | |
| Estimated payment obligations: | | | | | |
| Natural gas | 5,697.6 | 1,308.9 | 1,381.8 | 959.3 | 2,047.6 |
| NGLs | 2,943.0 | 997.0 | 669.1 | 659.4 | 617.5 |
| Crude oil | 237.3 | 237.3 | -- | -- | -- |
| Petrochemicals & refined products | 2,642.2 | 1,486.6 | 824.5 | 186.3 | 144.8 |
| Other | 114.1 | 21.2 | 24.1 | 22.8 | 46.0 |
| Underlying major volume commitments: | | | | | |
| Natural gas (in BBtus) | 969,180 | 221,530 | 230,450 | 165,008 | 352,192 |
| NGLs (in MBbls) | 49,300 | 19,048 | 10,496 | 10,316 | 9,440 |
| Crude oil (in MBbls) | 2,985 | 2,985 | -- | -- | -- |
| Petrochemicals & refined products (in MBbls) | 35,034 | 19,523 | 11,122 | 2,469 | 1,920 |
| Service payment commitments (5) | 575.6 | 72.0 | 113.7 | 110.1 | 279.8 |
| Capital expenditure commitments (6) | 497.5 | 497.5 | -- | -- | -- |
| Other long-term liabilities (7) | 155.2 | -- | 30.2 | 15.2 | 109.8 |
| Total | $ 36,875.6 | $ 5,879.5 | $ 6,404.4 | $ 5,291.3 | $ 19,300.4 |

(1) Represents our scheduled future maturities of consolidated debt principal obligations. 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.
(2) Our estimated cash payments for interest are based on the principal amount of consolidated debt obligations outstanding at December 31, 2009. With respect to variable-rate debt obligations, we applied the weighted-average interest rate paid during 2009 associated with such debt. 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 2009 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, 2009. 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 $550.0 million

Junior Subordinated Notes A (due August 2066), $682.7 million Junior Subordinated Notes B (due January 2068), $300.0 million Junior Subordinated Notes C (due June 2067) and TEPPCO Junior Subordinated Notes (due June 2067). Our estimated cash payments for interest assume that these subordinated notes are not called prior to their respective maturity dates.
(3) Primarily represents operating leases for (i) underground caverns for the storage of natural gas and NGLs, (ii) leased office space with an affiliate of EPCO and (iii) land held pursuant to right-of-way agreements.
(4) Represents enforceable and legally binding agreements to purchase goods or services under the terms of each agreement at December 31, 2009. The estimated payment obligations are based on contractual prices in effect at December 31, 2009 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery.
(5) Represents future payment commitments for services provided by third-parties.
(6) Represents short-term unconditional payment obligations relating to our capital projects, including our share of those of our unconsolidated affiliates, for services rendered or products purchased.
(7) As reflected on our Consolidated Balance Sheet at December 31, 2009, other long-term liabilities primarily represent noncurrent portions of asset retirement obligations, reserves for environmental remediation costs, accrued pipeline transportation deficiency fees, deferred revenues and the Centennial guarantee.

For additional information regarding our significant contractual obligations involving operating leases and purchase 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

Except for the following information regarding debt obligations of certain unconsolidated affiliates, we have no off-balance sheet arrangements, as described in Item 303(a)(4)(ii) of Regulation S-K, 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. The following information summarizes the significant terms of such unconsolidated debt obligations.

Poseidon. At December 31, 2009, Poseidon's debt obligations consisted of $92.0 million outstanding under its $150.0 million variable-rate revolving credit facility. Amounts borrowed under this facility mature in May 2011 and are secured by substantially all of Poseidon's assets. Poseidon expects to fund the repayment of its revolving credit facility (including accrued interest) with a variety of sources (either separately or in combination) including operating cash flows, refinancing agreements or cash contributions from its joint venture partners.

Evangeline. At December 31, 2009, Evangeline's debt obligations consisted of (i) $3.2 million in principal amount of 9.90% fixed rate Series B senior secured notes due December 2010 and (ii) a $7.5 million subordinated note payable due in 2011. Evangeline expects to fund the repayment of its debt obligations (including accrued interest) using operating cash flows.

Centennial. At December 31, 2009, Centennial's debt obligations consisted of $120.0 million borrowed under a master shelf loan agreement through two private placements, with interest rates ranging from 7.99% to 8.09%. Borrowings under the master shelf agreement mature in May 2024 and are collateralized by substantially all of Centennial's assets and severally guaranteed by Centennial's owners. Specifically, we and our joint venture partner in Centennial have each guaranteed one-half of Centennial's debt obligations. If Centennial were to default on its debt obligations, our estimated payment obligation would be $60.0 million based on amounts outstanding at December 31, 2009.

Related Party Transactions

For 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 our non-GAAP measure of total segment gross operating margin to GAAP operating income and income before provision for income taxes for the periods indicated (dollars in millions):

| | For Year Ended December 31, | | |
|---|---|---|---|
| | 2009 | 2008 | 2007 |
| Total segment gross operating margin | $2,839.8 | $2,609.0 | $1,964.4 |
| Adjustments to reconcile total segment gross operating margin to operating income: | | | |
| Depreciation, amortization and accretion in operating costs and expenses | (809.3) | (725.4) | (647.9) |
| Impairment charges in operating costs and expenses | (33.5) | -- | -- |
| Operating lease expenses paid by EPCO | (0.7) | (2.0) | (2.1) |
| Gain from asset sales and related transactions in operating costs and expenses | -- | 4.0 | 7.8 |
| General and administrative costs | (172.3) | (137.2) | (127.2) |
| Operating income | 1,824.0 | 1,748.4 | 1,195.0 |
| Other expense, net | (643.6) | (528.5) | (341.3) |

| | | | |
|---|---|---|---|
| Income before provision for income taxes | $1,180.4 | $1,219.9 | $853.7 |

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Recent Accounting Developments

The accounting standard setting bodies have recently issued the following guidance that will or may affect our future financial statements:

§ Fair Value Measurements; and

§ Consolidation of Variable Interest Entities.

For additional information regarding recent accounting developments, see Note 3 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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

In the course of our normal business operations, we are exposed to certain risks, including changes in interest rates, commodity prices and, to a limited extent, foreign exchange rates. In order to manage risks associated with certain identifiable and anticipated transactions, we use derivative instruments. Derivatives are instruments whose fair value is determined by changes in a specified benchmark such as interest rates, commodity prices or currency values. Typical derivative instruments include futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

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 outstanding and related hedging activities, including associated fair value measurements. See Note 13 of the Notes to Consolidated Financial Statements for information regarding the impact of derivative instruments on accumulated other comprehensive loss as reported on our Consolidated Balance Sheets.

Interest Rate Derivative Instruments

We utilize interest rate swaps, treasury locks and similar derivative instruments to manage our exposure to changes in the interest rates of certain consolidated debt agreements. This strategy is a component in controlling our cost of capital associated with such borrowings.

The following tables show the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value ("FV") of our interest rate swap portfolios at the dates presented (dollars in millions):

| Enterprise Products Partners (excluding Duncan Energy Partners) | | Swap Fair Value at | | |
|---|---|---|---|---|
| Scenario | Resulting Classification | December 31, 2008 | December 31, 2009 | January 31, 2010 |
| FV assuming no change in underlying interest rates | Asset | $46.7 | $41.3 | $53.2 |
| FV assuming 10% increase in underlying interest rates | Asset | 42.4 | 35.0 | 47.9 |
| FV assuming 10% decrease in underlying interest rates | Asset | 51.1 | 47.8 | 58.5 |

Duncan Energy Partners

| Scenario | Resulting Classification | Swap Fair Value at December 31, 2008 | December 31, 2009 | January 31, 2010 |
|---|---|---|---|---|
| FV assuming no change in underlying interest rates | Liability | $(9.8) | $(5.5) | $(5.7) |
| FV assuming 10% increase in underlying interest rates | Liability | (9.4) | (5.5) | (5.7) |
| FV assuming 10% decrease in underlying interest rates | Liability | (10.2) | (5.6) | (5.7) |

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The following table shows the effect of hypothetical price movements on the estimated fair value of our forward starting swap portfolio at the dates presented (dollars in millions):

| Scenario | Resulting Classification | Swap Fair Value at December 31, 2009 | January 31, 2010 |
|---|---|---|---|
| FV assuming no change in underlying interest rates | Asset | $21.0 | $13.3 |
| FV assuming 10% increase in underlying interest rates | Asset | 31.1 | 26.1 |
| FV assuming 10% decrease in underlying interest rates | Asset (Liability) | 10.5 | (0.5) |

In January 2010, we entered into two additional forward starting interest rate swaps with a notional amount of $50.0 million each. In February 2010, we entered into three additional forward starting swaps with a notional amount of $50.0 million each. The period hedged by these five forward starting swaps is February 2012 through February 2022.

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. We may use commodity-based derivative instruments such as forward contracts, futures, swaps and options to mitigate such risks.

We assess the risk of our commodity financial instrument portfolios using a sensitivity analysis model. The sensitivity analysis applied to these portfolios measures the potential income or loss (i.e., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity derivative instruments outstanding at the date indicated within the following tables.

The following table shows the effect of hypothetical price movements on the estimated fair value of our natural gas marketing portfolio at the dates presented (dollars in millions):

| Scenario | Resulting Classification | Swap Fair Value at December 31, 2008 | December 31, 2009 | January 31, 2010 |
|---|---|---|---|---|
| FV assuming no change in underlying commodity prices | Asset (Liability) | $6.5 | $(1.5) | $(2.3) |
| FV assuming 10% increase in underlying commodity prices | Asset (Liability) | 2.7 | (7.0) | (6.3) |
| FV assuming 10% decrease in underlying commodity prices | Asset | 9.9 | 4.1 | 1.8 |

The following table shows the effect of hypothetical price movements on the estimated fair value of our NGL, refined products and petrochemical operations portfolio at the dates presented (dollars in millions):

| Scenario | Resulting Classification | Swap Fair Value at December 31, 2008 | December 31, 2009 | January 31, 2010 |
|---|---|---|---|---|
| | Asset (Liability) | $(102.1) | $(9.2) | $21.3 |

| | | | | |
|---|---|---|---|---|
| FV assuming no change in underlying commodity prices | | | | |
| FV assuming 10% increase in underlying commodity prices | Liability | (94.0 ) | (43.2 ) | (19.5 ) |
| FV assuming 10% decrease in underlying commodity prices | Asset (Liability) | (110.1 ) | 24.8 | 62.0 |

The following table shows the effect of hypothetical price movements on the estimated fair value of our crude oil marketing portfolio at the dates presented (dollars in millions):

| | | Swap Fair Value at | | |
|---|---|---|---|---|
| Scenario | Resulting Classification | December 31, 2008 | December 31, 2009 | January 31, 2010 |
| FV assuming no change in underlying commodity prices | Asset | $-- | $2.0 | $1.1 |
| FV assuming 10% increase in underlying commodity prices | Asset | -- | 2.0 | 1.1 |
| FV assuming 10% decrease in underlying commodity prices | Asset | -- | 2.1 | 1.1 |

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Our predominant hedging strategy is to hedge an amount of gross margin associated with the gas processing activities. We achieve this by using physical and financial instruments to lock in the prices of NGL sales and natural gas purchases used for PTR. This program consists of:

§ the forward sale of a portion of our expected equity NGL production at fixed prices through December 2010, achieved through the use of forward physical sales and commodity derivative instruments and

§ the purchase of commodity derivative instruments with a notional amount determined by the amount of natural gas expected to be consumed as PTR in the production of such equity NGL production.

At December 31, 2009, this program had hedged future estimated gross margins (before plant operating expenses) of $178.9 million on 6.0 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through December 2010. At February 22, 2010, this program had hedged future estimated gross margins (before plant operating expenses) of $344.0 million on 10.8 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through December 2010. 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.

Foreign Currency Derivative Instruments

We are exposed to a nominal amount of foreign currency exchange risk in connection with our NGL marketing activities in Canada. As a result, we could be adversely affected by fluctuations in currency rates between the U.S. dollar and Canadian dollar. In order to manage this risk, we may enter into foreign exchange purchase contracts to lock in the exchange rate. At December 31, 2009, we had foreign currency derivative instruments outstanding with a notional amount of $4.1 million Canadian dollars. The fair value of this instrument was an asset of $0.2 million at December 31, 2009.

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 "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") begin 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 (our principal executive officer) (the "CEO") and our general partner's chief financial officer (our principal financial officer) (the "CFO"), 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, the CEO and CFO 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 the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure; 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) or in other factors during the fourth quarter of 2009, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

The certifications of our general partner's CEO and CFO required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this annual report.

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## MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2009

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 Enterprise Products Partners' management and Board of Directors regarding the preparation and fair presentation of published financial statements. However, our management does not represent that our disclosure controls and procedures or internal controls over financial reporting will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only a reasonable, not an absolute, assurance that the objectives of the control system are met.

Our management assessed the effectiveness of Enterprise Products Partners' internal control over financial reporting as of December 31, 2009. In making this assessment, it 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, 2009, Enterprise Products Partners' internal control over financial reporting is effective based on those criteria.

Our Audit, Conflicts and Governance Committee is composed of directors who are not officers or employees of our general partner. It meets regularly with members of management, the internal auditors and the representatives of the independent registered public accounting firm to discuss the adequacy of Enterprise Products Partners' internal controls over financial reporting, financial statements and the nature, extent and results of the audit effort. Management reviews with the Audit, Conflicts and Governance Committee all of Enterprise Products Partners' significant accounting policies and assumptions affecting the results of operations. Both the independent registered public accounting firm and internal auditors have direct access to the Audit, Conflicts and Governance Committee without the presence of management.

Our independent registered public accounting firm has issued an attestation report on 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 March 1, 2010.

| | | | |
|---|---|---|---|
| /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 GP, LLC | Title: | Chief Financial Officer of our general partner, Enterprise Products GP, LLC |

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products GP, LLC and
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, 2009, 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, 2009. 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, 2009, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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, 2009 of the Company and our report dated March 1, 2010 expresses an unqualified opinion on those financial

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statements and includes an explanatory paragraph concerning the retroactive effects of the common control acquisition of TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC by the Company on October 26, 2009 and the related change in business segments described in Note 1.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2010

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 the management or operations of our business. These functions are performed by the employees of EPCO pursuant to the ASA under the direction of the Board of Directors (the "Board") and executive officers of EPGP. For a description of the ASA, see "Relationship with EPCO and Affiliates – EPCO ASA" in Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The executive officers of our general partner 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 our general partner. Dan. L. Duncan, through his indirect control of EPGP, has 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 our general partner serves until such member's death, resignation or removal. The employees of EPCO who served as directors of EPGP during 2009 were Messrs. Duncan, Creel, Fowler, Cunningham, Bachmann and Teague.

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. Accordingly, we have elected to not 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 our general partner maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Notwithstanding any contractual limitation on its obligations or duties, EPGP 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 EPGP. Whenever possible, EPGP 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

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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.

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 EPGP or us (either directly or as a partner, unitholder or officer of an organization that has a material relationship with EPGP or us). Based on the foregoing, the Board has affirmatively determined that Messrs. Ross, Rampacek and Barnett are "independent" directors under the NYSE rules.

Code of Conduct and Ethics and Corporate Governance Guidelines

EPGP 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, the reporting of compliance issues and discipline for violations of the code. The Code of Conduct also establishes policies applicable to our chief executive officer, chief financial officer, 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).

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 ACG 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.

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 and other matters, through our Internet website, www.epplp.com. You may also contact our Investor Relations department at (866) 230-0745 for printed copies of these documents free of charge.

ACG Committee

The sole committee of the Board is its ACG Committee. In accordance with NYSE rules and Section 3(a)(58)(A) of the Securities Exchange Act of 1934, the Board has named three of its members to serve on its ACG Committee. The members of the ACG Committee are independent directors, free from any relationship with us or any of our subsidiaries that would interfere with the exercise of independent judgment.

The members of the ACG Committee must have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements, and at least one member of the ACG Committee shall have accounting or related financial management expertise. The members of the ACG Committee are Messrs. Ross, Rampacek and Barnett. The Board has affirmatively determined that Mr.

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Rampacek satisfies the definition of "audit committee financial expert" as defined in Item 407(d) of Regulation S-K promulgated by the SEC.

The ACG Committee's duties are addressing audit and conflicts-related items and general corporate governance matters. From an audit and conflicts standpoint, the primary responsibilities of the ACG Committee include:

§ reviewing potential conflicts of interests, including related party transactions;

§ monitoring the integrity of our financial reporting process and related systems of internal control;

§ ensuring our legal and regulatory compliance and that of EPGP;

§ overseeing the independence and performance of our independent public accountant;

§ approving all services performed by our independent public accountant;

§ providing for an avenue of communication among the independent public accountant, management, internal audit function and the Board;

§ encouraging adherence to and continuous improvement of our policies, procedures and practices at all levels;

§ reviewing areas of potential significant financial risk to our businesses; and

§ 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 ACG 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 ACG Committee are conclusively deemed to be fair and reasonable to our business, approved by all of our partners and not a breach by EPGP or the Board of any duties they may owe us or our unitholders.

Pursuant to its formal written charter, the ACG 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 ACG 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.

From a governance standpoint, the primary duties and responsibilities of the ACG Committee are to recommend to the Board a set of governance principles applicable to us and review such guidelines from time to time, making any changes that the ACG Committee deems necessary. The ACG Committee assists the Board in fulfilling its oversight responsibilities.

A copy of the ACG Committee charter is available on our website, www.epplp.com. You may also contact our Investor Relations department at (866) 230-0745 for a printed copy of this document free of charge.

NYSE Corporate Governance Listing Standards

On March 20, 2009, Michael A. 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 20, 2009.

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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. Barnett.

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 ACG 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 EPGP

The following table sets forth the name, age and position of each of the directors and executive officers of EPGP at March 1, 2010. Each executive officer holds the same respective office shown below in the general partner of EPO.

| Name | Age | Position with EPGP |
|---|---|---|
| Dan L. Duncan (1) | 77 | Director and Chairman |
| Michael A. Creel (1) | 56 | Director, President and CEO |
| W. Randall Fowler (1) | 53 | Director, Executive Vice President and CFO |
| Richard H. Bachmann (1) | 57 | Director, Executive Vice President, Chief Legal Officer and Secretary |
| A. James Teague (1) | 64 | Director, Executive Vice President and Chief Commercial Officer |
| Dr. Ralph S. Cunningham | 69 | Director |
| E. William Barnett (2,3) | 77 | Director |
| Rex C. Ross (2) | 66 | Director |
| Charles M. Rampacek (2) | 66 | Director |
| William Ordemann (1) | 50 | Executive Vice President and Chief Operating Officer |
| Lynn L. Bourdon, III (1) | 48 | Senior Vice President |
| Bryan F. Bulawa (1) | 40 | Senior Vice President and Treasurer |
| James M. Collingsworth (1) | 55 | Senior Vice President |
| Mark Hurley (1) | 51 | Senior Vice President |
| Michael J. Knesek (1) | 55 | Senior Vice President, Controller and Principal Accounting Officer |
| Christopher Skoog (1) | 46 | Senior Vice President |
| Thomas M. Zulim (1) | 52 | Senior Vice President |

(1) Executive officer
(2) Member of ACG Committee
(3) Chairman of ACG Committee

The following information presents a brief history of the business experience of our directors and executive officers serving as of March 1, 2010:

Dan L. Duncan. Mr. Duncan was elected Chairman and a Director of EPGP in April 1998, Chairman and a Director of the general partner (now the managing member) of EPO in December 2003, Chairman and a Director of EPE

Holdings in August 2005 and Chairman and a Director of DEP GP in October 2006. Mr. Duncan served as the sole Chairman of EPCO from 1979 to December 2007. Mr. Duncan now serves as Group Co-Chairman of EPCO with his daughter, Ms. Randa Duncan Williams, who is also a Director of EPE Holdings. In December 2009, Mr. Duncan was appointed as a Director of LE GP, the general partner of Energy Transfer Equity. He also serves as an Honorary Trustee of the Board of Trustees of the Texas Heart Institute at Saint Luke's Episcopal Hospital and on the Board of Trustees of the Baylor College of Medicine.

Michael A. Creel. Mr. Creel was elected President and CEO of EPGP in August 2007. From June 2000 to August 2007, Mr. Creel served as CFO of EPGP and an Executive Vice President of EPGP from

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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.

In December 2007, Mr. Creel was elected Group Vice Chairman and CFO of EPCO. Prior to these elections in EPCO, Mr. Creel served as Chief Operating Officer from April 2005 to December 2007 and CFO from June 2000 to April 2005 for EPCO. He also serves as a Director of EPE Holdings, DEP GP and EPGP since October 2009, October 2006 and February 2006, respectively. Mr. Creel served as President, CEO and a Director of EPE Holdings from August 2005 through August 2007. From October 2006 to August 2007, Mr. Creel served as the CFO and an Executive Vice President 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.

W. Randall Fowler. Mr. Fowler was elected Executive Vice President and CFO of EPGP, EPE Holdings and DEP GP in August 2007. 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 has also served as a Director of EPGP and of EPE Holdings since February 2006 and of DEP GP since September 2006. Mr. Fowler also served as Senior Vice President and CFO of EPE Holdings from August 2005 to August 2007.

Mr. Fowler was elected President and CEO of EPCO in December 2007. Prior to these elections, he served as CFO of EPCO from April 2005 to December 2007. Mr. Fowler, a Certified Public Accountant (inactive), joined Enterprise Products Partners 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.

Richard H. Bachmann. Mr. Bachmann was elected an Executive Vice President and the Chief Legal Officer of EPGP in February 1999, was elected Secretary of EPGP in November 1999 and was elected a Director of EPGP in February 2006. He previously served as a Director of EPGP from June 2000 to January 2004. Mr. Bachmann has served as Executive Vice President, Chief Legal Officer and Secretary of EPE Holdings since April 2005.

Mr. Bachmann was elected as the Chief Legal Officer and Secretary of EPCO in May 1999 and as a Group Vice Chairman of EPCO in December 2007. In October 2006, Mr. Bachmann was elected President, CEO and a Director of DEP GP. Mr. Bachmann was also elected a Director of EPE Holdings in February 2006. Since January 1999, Mr. Bachmann has served as a Director of EPCO. 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.

A. James Teague. Mr. Teague was elected an Executive Vice President of EPGP in November 1999 and additionally as our Chief Commercial Officer and a Director in July 2008. He also serves as a Director of EPE Holdings (since October 2009) and as Director, Executive Vice President and Chief Commercial Officer of DEP GP (since July 2008). Mr. Teague joined us in connection with our purchase of certain midstream energy assets from affiliates of Shell 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.

Dr. Ralph S. Cunningham. Dr. Cunningham was elected a Director of EPGP in February 2006 having previously served as a Director of EPGP from 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. In August 2007, Dr. Cunningham was elected a Director of DEP GP and a Director, the President and CEO of EPE Holdings. He served as Chairman and a Director of TEPPCO GP from March 2005 until November 2005.

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Dr. Cunningham was elected a Group Vice Chairman of EPCO in December 2007 having previously served as a Director of EPCO from 1987 to 1997. He serves as a Director of Tetra Technologies, Inc. (a publicly traded energy services and chemical company), LE GP, the general partner of Energy Transfer Equity (a publicly traded energy services partnership) and Agrium, Inc. (a Canadian publicly traded agricultural chemicals company). In addition, Dr. Cunningham serves as a Director and the Chairman of the Safety, Health and Responsibility Committee of Cenovus Energy Inc. (a Canadian publicly traded oil company). Dr. Cunningham retired in 1997 from CITGO Petroleum Corporation, where he had served as President and CEO since 1995.

E. William Barnett. Mr. Barnett was elected a Director of EPGP in March 2005. Mr. Barnett is a member of our ACG Committee and serves as its Chairman. 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; and a Director Emeritus and former Chairman of the Houston Zoo, Inc. (the operating arm of the Houston Zoo). He is a Director of RRI Energy, Inc. (a publicly traded electric services 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. Mr. Barnett served as a Trustee of the Baylor College of Medicine from 1993 until 2004.

Rex C. Ross. Mr. Ross was elected a Director of EPGP in October 2006 and is a member of its ACG Committee. 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 United States. Prior to his executive 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 Committee.

Charles M. Rampacek. Mr. Rampacek was elected a Director of EPGP in October 2006 and is a member of its ACG Committee. Mr. Rampacek is currently a business and management consultant in the energy industry. Mr. Rampacek served as Chairman, CEO and President of Probex Corporation ("Probex"), an energy technology company that developed a proprietary used oil recovery process, from 2000 until his retirement in 2003. Prior to joining Probex, Mr. Rampacek was President and CEO of Lyondell-Citgo Refining L.P, a manufacturer of petroleum products, from 1996 through 2000. From 1982 to 1995, he held various executive positions with Tenneco Inc. and its energy-related subsidiaries, including President of Tenneco Gas Transportation Company, Executive Vice President of Tenneco Gas Operations and Senior Vice President of Refining and Supply. Mr. Rampacek also spent 16 years with Exxon Company USA, where he held various supervisory and management positions. Mr. Rampacek has been a Director of Flowserve Corporation since 1998 and is Chairman of its Corporate Governance and Nominating Committee and a member of its Organization and Compensation Committee. Mr. Rampacek also serves as a Director of Cenovus Energy Inc. (a Canadian publicly traded oil company).

In 2005, two complaints requesting recovery of certain costs were filed against former officers and directors of Probex as a result of the bankruptcy of Probex in 2003. These complaints were defended under Probex's director and officer insurance with American International Group, Inc. ("AIG") and settlement was reached and paid by AIG with bankruptcy court approval in the first half of 2006. An additional complaint was filed in 2005 against noteholders of certain Probex debt of which Mr. Rampacek was one. A settlement of $2 thousand was reached and approved by the bankruptcy court in the first half of 2006.

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William Ordemann. Mr. Ordemann was elected an Executive Vice President and the Chief Operating Officer of EPGP in August 2007. He was also elected an Executive Vice President of DEP GP in August 2007. 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 us in connection with our purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. Prior to joining us, 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 as a Senior Vice President, Supply & Marketing of EPGP in 2004 after serving as Senior Vice President and Chief Commercial Officer with Orion Refining Corporation and as a Partner in En*Vantage, Inc. Prior to that time, Mr. Bourdon was Senior Vice President of Commercial Operations for PG&E Gas Transmission and Vice President, NGL Marketing & Development at the predecessor company, Valero. Earlier in his career, Mr. Bourdon served 12 years with Dow Chemical Company in the engineering, business and commercial areas.

Bryan F. Bulawa. Mr. Bulawa was elected Senior Vice President and Treasurer of EPGP, EPE Holdings and DEP GP in October 2009, having served as Vice President and Treasurer of EPGP since July 2007. Prior to joining Enterprise, Mr. Bulawa spent 13 years at Scotia Capital, where he served as director of the firm’s U.S. Energy Corporate Finance and Distribution group.

James M. Collingsworth. Mr. Collingsworth was elected Vice President of EPGP in November 2001 and Senior Vice President in November 2002. 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.

Mark A. Hurley. Mr. Hurley joined EPGP on March 1, 2010 as Senior Vice President, Crude Oil & Offshore. Prior to joining EPGP, Mr. Hurley was a Shell employee and recently served as President of Shell Pipeline Company, a crude oil, refined products and natural gas energy 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 profitability, operations, strategy, business development and capital project development.

Michael J. Knesek. Mr. Knesek, a Certified Public Accountant, was elected a Senior Vice President of EPGP in February 2005, having served as a Vice President of EPGP since August 2000. Mr. Knesek has been the Principal Accounting Officer and Controller of EPGP since August 2000, of EPE Holdings since August 2005 and of DEP GP since September 2006. He has served as Senior Vice President of EPE Holdings since August 2005 and of DEP GP since September 2006. 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 joined the partnership in July 2007 as Senior Vice President of EPGP to develop and lead Enterprise Product Partners' Natural Gas Services and Marketing group. In July 2008, he also assumed responsibility for Enterprise Product Partners' 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 EPGP and EPCO, Inc., with responsibility for the partnership's unregulated NGL business. From March 2006 to July 2008, Mr. Zulim served as Senior Vice President, Human Resources, for both EPGP and EPCO, and served

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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 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 the following persons should serve as a director of our general partner.

Six of our directors are 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 Mr. Duncan, over 55 years of ownership and management of a number of midstream businesses, including as one of the founders of Enterprise Products Partners; for Mr. Creel, over 30 years of management experience with midstream assets, for both third parties and Enterprise Products Partners, including finance and accounting (certified public accountant) and more than six years of management experience in the financial industry; for Mr. Fowler, over ten years of experience with our midstream assets, including finance, accounting (inactive certified public accountant) and investor public relations and, for over the last six years, as a member of Enterprise Products Partners' executive management team; for Mr. Bachmann, over 28 years of experience with our midstream assets, including legal, regulatory, contract and merger and acquisitions and, for over the last ten years, as a member of Enterprise Products Partners' executive management team; 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 Products Partners' businesses; and for Dr. Cunningham, over 45 years of refined products, chemicals, and midstream businesses.

Our three 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. Barnett, legal, regulatory and management skills as a former managing partner of an international law firm; for Mr. Ross, executive management of oilfield services businesses; and for Mr. Rampacek, executive management of petroleum products refining, transportation and supply businesses.

Section 16(a) Beneficial Ownership Reporting Compliance

Under federal securities laws, EPGP, directors and executive officers of EPGP, and certain other officers, 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 2009, except that (i) on March 9, 2009, Mr. Collingsworth filed one late Form 3 reporting his new status as an executive officer of EPGP and (ii) on August 13, 2009, Mr. Collingsworth filed one late Form 4 reporting the in-kind payment of a Federal income tax obligation.

Item 11. Executive Compensation.

Executive Officer Compensation

We do not directly employ any of the persons responsible for managing our partnership. Instead, we are managed by our general partner, the executive officers of which are employees of EPCO, a privately held company controlled by Dan L. Duncan. 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 EPCO's compensation costs related to our partnership. For additional information

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regarding the ASA, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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, 2009, 2008 and 2007 for the CEO, CFO and three other most highly compensated executive officers of our general partner as of December 31, 2009. Collectively, these five individuals were our “named executive officers” for 2009.

| Name and Principal Position | Year | Cash Salary ($) | Cash Bonus ($) (1) | Unit Awards ($) (2) | Option Awards ($) (3) | All Other Comp. ($) (4) | Total ($) |
|---|---|---|---|---|---|---|---|
| Michael A. Creel | 2009 | $ 580,000 | $ 1,280,000 | $ 2,616,695 | $ 718,920 | $ 216,630 | $ 5,412,245 |
| (President and CEO) | 2008 | 563,200 | 552,000 | 3,668,620 | 171,360 | 200,241 | 5,155,421 |
| | 2007 | 361,808 | 365,370 | 1,435,901 | 94,390 | 108,017 | 2,365,486 |
| W. Randall Fowler | 2009 | 206,719 | 354,375 | 973,475 | 242,422 | 80,271 | 1,857,262 |
| (Executive Vice President and CFO) | 2008 | 190,781 | 131,250 | 1,377,456 | 53,550 | 62,646 | 1,815,683 |
| | 2007 | 213,145 | 129,720 | 1,026,528 | 57,526 | 53,425 | 1,480,344 |
| A. James Teague | 2009 | 650,000 | 950,000 | 2,445,585 | 665,400 | 233,747 | 4,944,732 |
| (Executive Vice President and | 2008 | 558,333 | 500,000 | 3,627,701 | 142,800 | 176,651 | 5,005,485 |
| Chief Commercial Officer) | 2007 | 445,660 | 300,000 | 2,175,230 | 160,800 | 110,336 | 3,192,026 |
| William Ordemann | 2009 | 395,200 | 310,000 | 1,643,242 | 565,950 | 220,470 | 3,134,862 |
| (Executive Vice President and | 2008 | 391,400 | 265,000 | 1,779,805 | 142,800 | 157,884 | 2,736,889 |
| Chief Operating Officer) | 2007 | 331,337 | 228,000 | 1,554,414 | 80,400 | 86,671 | 2,280,822 |
| Richard H. Bachmann | 2009 | 346,688 | 510,625 | 1,480,455 | 357,653 | 127,103 | 2,822,524 |
| (Executive Vice President and | 2008 | 351,313 | 233,750 | 2,140,435 | 78,540 | 129,921 | 2,933,959 |
| Chief Legal Officer) | 2007 | 306,900 | 186,000 | 1,264,670 | 83,134 | 94,752 | 1,935,456 |

(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 for 2009 were paid in February 2010).
(2) Amounts represent the aggregate grant date fair value of restricted unit and profits interests awards in the Employee Partnerships 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, which information is incorporated by reference herein.

(3) Amounts represent 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, which information is incorporated by reference herein.

(4) Amounts primarily represent (i) matching contributions under funded, qualified, defined contribution retirement plans, (ii) quarterly distributions paid on incentive plan awards and (iii) the imputed value of life insurance premiums paid on behalf of the officer.

Each of the named executive officers continues to perform services for other affiliates of EPCO. Under the ASA, the compensation costs of our named executive officers are allocated to us and our affiliates based on the estimated amount of time that each officer spends on our consolidated businesses in any fiscal year. These percentages are reassessed at least quarterly.

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The following table presents the average approximate amount of time devoted by each of our named executive officers to our consolidated businesses, which includes Duncan Energy Partners, and those of our other affiliates for each of the years presented.

| Named Executive Officer | Year | Enterprise Products Partners | EPCO and other affiliates | Total Time Allocated |
|---|---|---|---|---|
| Michael A. Creel (CEO) | 2009 | 80% | 20% | 100% |
| | 2008 | 80% | 20% | 100% |
| | 2007 | 59% | 41% | 100% |
| W. Randall Fowler (CFO) | 2009 | 40% | 60% | 100% |
| | 2008 | 38% | 62% | 100% |
| | 2007 | 48% | 52% | 100% |
| A. James Teague | 2009 | 100% | -- | 100% |
| | 2008 | 100% | -- | 100% |
| | 2007 | 100% | -- | 100% |
| William Ordemann | 2009 | 100% | -- | 100% |
| | 2008 | 100% | -- | 100% |
| | 2007 | 100% | -- | 100% |
| Richard H. Bachmann | 2009 | 54% | 46% | 100% |
| | 2008 | 55% | 45% | 100% |
| | 2007 | 52% | 48% | 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 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.  Dan L. Duncan controls EPCO and has ultimate decision-making authority with respect to the compensation of our 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 ACG Committee of our general partner.  Equity awards under EPCO's long-term incentive plans are approved by the ACG Committee of the respective issuer.  We do not have a separate compensation committee.

As discussed below, the elements of EPCO's compensation program, along with EPCO's other rewards (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 the partnership and individual levels.  With respect to the three years ended December 31, 2009, EPCO's compensation package for named executive officers did not include any elements based on targeted performance-related criteria.

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, 2009, the elements of compensation for the named executive officers consisted of the following:

§ 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 Mr. Duncan and EPCO with compensation decisions, Mr. Creel and Dr. Cunningham (both Group Vice Chairmen for EPCO) and the senior vice president of Human Resources for EPCO formulate preliminary compensation recommendations for each of the named executive officers other than our CEO. Mr. Duncan, after consulting with the senior vice president of Human Resources for EPCO, independently makes compensation decisions with respect to the named executive officers. 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.

Periodically, EPCO will engage a third-party consultant to review compensation elements provided to our executive officers. In 2009, EPCO engaged Hewitt & Associates (“Hewitt”) to review executive compensation relative to our industry. Hewitt provided comparative market data on compensation practices and programs for executive level positions based on an analysis of industry competitors and external trends. Neither we, nor EPCO, which engages the consultant, are aware of the identity of the companies whose data was used from the consultant’s proprietary data base for specific positions. EPCO uses the information provided in the Hewitt analysis to gauge whether compensation levels reported by the consultant are within the general ranges of compensation for EPCO employees in similar positions, but that comparison is only a factor taken into consideration and may or may not impact compensation of our executive officers, for which Dan L. Duncan has the ultimate decision-making authority. EPCO does not otherwise engage in benchmarking for the named executive officers’ positions.

Mr. Duncan and EPCO do not use any formula or specific performance-based criteria for our named executive officers in connection with determining compensation for services performed for us; rather, Mr. Duncan 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 Mr. Duncan 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. Mr. Duncan and EPCO also consider individual performance, levels of responsibility and value to the organization. All compensation determinations are discretionary and, as noted above, subject to Mr. Duncan’s ultimate decision-making authority, except for equity awards under EPCO’s long-term incentive plans, as discussed below.

We believe 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.

The discretionary cash bonus awards paid to each of our named executive officers were determined by consultation, as appropriate, among Mr. Duncan, Mr. Creel, Dr. Cunningham, Mr. Bachmann and the senior vice president of Human Resources for EPCO, subject to Mr. Duncan’s final determination. 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 perform services. It is EPCO’s general policy to pay these awards in February of the following year.

The awards granted under EPCO’s long-term incentive plans to our named executive officers were determined by consultation among Mr. Duncan, Mr. Creel and the senior vice president of Human Resources for EPCO, and were approved by the ACG Committee of the respective issuer.  In addition, our

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named executive officers are Class B limited partners in certain of the Employee Partnerships. Mr. Duncan approves the issuance of all limited partnership interests in the Employee Partnerships to our named executive officers. See "Summary of Long-Term Incentive Arrangements Underlying 2009 Award Grants" below for information regarding EPCO's long-term incentive plans.

EPCO generally does not pay for perquisites for any of our named executive officers, other than reimbursement of certain parking expenses, and expects to continue its policy of covering limited perquisites allocable 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, 2009.

In December 2009, EPCO and the partners of each of the Employee Partnerships amended the partnership agreement of each of the Employee Partnerships to provide that the expected liquidation date for such Employee Partnership will be in February 2016. The extensions of the expected liquidation dates were intended to align the interests of the employee partners of the Employee Partnerships with the long-term interests of EPCO and other unitholders in the relevant underlying publicly traded partnerships, which also hold indirectly a significant ownership interest in both us and our subsidiaries.

Also in December 2009, the Board implemented certain equity ownership guidelines for directors and executive officers of our general partner in order to further align their interests and actions with the interests of our partnership and its unitholders. See "Security Ownership of Management" within Item 12 of this annual report for additional information. Our compensation practices for our named executive officers are not expected to be impacted by this new policy.

We believe that each of the base salary, cash bonus awards, and long-term incentive awards fit the overall compensation objectives of us and of EPCO and are designed to avoid risks that are likely to conflict with the partnership's risk management policies.

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Grants of Plan-Based Awards in Fiscal Year 2009

The following table presents information concerning each grant of a plan-based award made to a named executive officer in 2009 for which we will be allocated by EPCO our pro rata share under the ASA. The restricted unit and unit option awards granted during 2009 were under EPCO's long-term incentive plans. See "Summary of Long-Term Incentive Arrangements Underlying 2009 Award Grants" within this discussion of compensation of directors and executive officers for additional information regarding the long-term incentive plans under which these awards were granted.

| | | Estimated Future Payouts Under Equity Incentive Plan Awards | | | Exercise or Base Price of Option Awards | Grant Date Fair Value of Unit and Option Awards |
|---|---|---|---|---|---|---|
| Name | Grant Date | Threshold (#) | Target (#) | Maximum (#) | ($/Unit) | ($) (1) |
| Restricted unit awards: (2) | | | | | | |
| Michael A. Creel (CEO) | 5/06/09 | -- | 50,600 | -- | -- | $ 1,008,762 |
| W. Randall Fowler (CFO) | 5/06/09 | -- | 34,000 | -- | -- | 333,659 |
| A. James Teague | 5/06/09 | -- | 37,400 | -- | -- | 932,008 |
| Richard H. Bachmann | 5/06/09 | -- | 37,400 | -- | -- | 500,954 |
| William Ordemann | 5/06/09 | -- | 30,000 | -- | -- | 747,600 |
| Unit option awards: (3) | | | | | | |
| Michael A. Creel (CEO) | 2/19/09 | -- | 75,000 | -- | 22.06 | 397,800 |
| | 5/06/09 | -- | 90,000 | -- | 24.92 | 321,120 |
| W. Randall Fowler (CFO) | 2/19/09 | -- | 52,500 | -- | 22.06 | 137,072 |
| | 5/06/09 | -- | 60,000 | -- | 24.92 | 105,381 |
| A. James Teague | 2/19/09 | -- | 60,000 | -- | 22.06 | 397,800 |
| | 5/06/09 | -- | 60,000 | -- | 24.92 | 267,600 |
| Richard H. Bachmann | 2/19/09 | -- | 60,000 | -- | 22.06 | 213,818 |
| | 5/06/09 | -- | 60,000 | -- | 24.92 | 143,835 |
| William Ordemann | 2/19/09 | -- | 45,000 | -- | 22.06 | 298,350 |
| | 5/06/09 | -- | 60,000 | -- | 24.92 | 267,600 |
| Profits interest awards: (4) | | | | | | |
| Michael A. Creel (CEO) | 12/02/09 | -- | -- | -- | -- | 1,607,933 |
| W. Randall Fowler (CFO) | 12/02/09 | -- | -- | -- | -- | 639,940 |
| A. James Teague | 12/02/09 | -- | -- | -- | -- | 1,513,577 |
| Richard H. Bachmann | 12/02/09 | -- | -- | -- | -- | 979,501 |
| William Ordemann | 12/02/09 | -- | -- | -- | -- | 895,642 |

(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 business activities during 2009. Based on current allocations, we estimate that the consolidated compensation expense we record for each named executive officer with respect to these awards will equal these amounts over the vesting period.
(2) Awards granted during 2009 were made under the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan").
(3) Awards granted during 2009 were made under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan").
(4) Awards represent each named executive officer's share of the aggregate incremental fair value resulting from the extension of the liquidation date (a material modification of the underlying awards) of each Employee Partnership to

February 2016.

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.

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Summary of Long-Term Incentive Arrangements Underlying 2009 Award Grants

The following information summarizes the principal types of awards granted to our named executive officers under EPCO's long-term incentive plans. 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 units, phantom units, unit appreciation rights ("UARs") and distribution equivalent rights ("DERs"). Awards granted under the 2008 Plan may be in the form of unit options, restricted units, phantom units, UARs and DERs. As of December 31, 2009, no phantom unit awards, UARs or associated DERs have been granted under the EPCO plans to the named executive officers. No awards with respect to our common units have been granted in connection with these long-term incentive plans.

As additional long-term incentive arrangements, EPCO granted its key employees who perform services on behalf of us, EPCO and other affiliated companies "profits interests" in the Employee Partnerships, which are privately held affiliates of EPCO. The employees were issued Class B limited partner interests and admitted as Class B limited partners in the Employee Partnerships without any capital contributions.

Restricted unit awards. Restricted unit awards allow recipients to acquire common units of Enterprise Products Partners (at no cost to the recipient) 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 unit grants will vest at a rate of 25% per year beginning one year after the grant date. The fair value of restricted units is based on the market price per unit of the underlying security on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures. Each recipient is also entitled to cash distributions equal to the product of the number of restricted units outstanding for the participant and the cash distribution per unit paid by the respective issuer.

Unit option awards. Under the EPCO plans, non-qualified incentive options to purchase a fixed number of common units of Enterprise Products Partners may be granted to key employees of EPCO. When issued, the exercise price of each option grant is equivalent to the market price of the underlying equity on the date of grant. In general, options granted under the EPCO plans have a vesting period of four years and remain exercisable for five to ten years, as applicable, from the date of grant.

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 options, risk-free interest rates, expected distribution yield on our common units, and expected unit 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 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 our historical unit price volatility and distribution yield over a period equal to the expected life of the option.

Profits interests awards. Profits interest awards entitle each holder to participate in the expected long-term appreciation in value of the equity securities owned by each Employee Partnership. The Employee Partnerships in which the named executive officers participate own either units of Enterprise GP Holdings or Enterprise Products Partners or a combination of both.

Each Employee Partnership has a single Class A limited partner, which is a privately held indirect subsidiary of EPCO, and a varying number of Class B limited partners. At formation, the Class A limited partner either contributes cash or limited partner units it owns to the Employee Partnership. If cash is contributed, the Employee Partnership uses these funds to acquire limited partner units on the open market.  In general, the Class A limited partner earns a preferred return (either fixed or variable depending on the

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partnership agreement) on its investment ("Capital Base") in the Employee Partnership and residual quarterly cash amounts, if any, are distributed to the Class B limited partners. Upon liquidation, Employee Partnership assets having a fair market value equal to the Class A limited partner's Capital Base, plus any preferred return for the period in which liquidation occurs, will be distributed to the Class A limited partner. Any remaining assets will be distributed to the Class B limited partner(s) as a residual profits interest.

The estimated grant date fair values of the profits interests awards were determined using a Black-Scholes option pricing model and reflect adjustments for forfeitures, regrants and other modifications. The profits interests awards are subject to forfeiture.

The following table presents each named executive officer's share of the total profits interest in the Employee Partnerships at December 31, 2009:

| | Percentage Ownership of Class B Interests | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Named Executive Officer | EPE Unit I | | EPE Unit III | | Enterprise Unit | | EPCO Unit | |
| Michael A. Creel (CEO) | 9.3 | % | 8.9 | % | 18.5 | % | 20.0 | % |
| W. Randall Fowler (CFO) | 6.2 | % | 8.9 | % | 8.2 | % | 20.0 | % |
| A. James Teague | 6.2 | % | 7.4 | % | 10.3 | % | 20.0 | % |
| Richard H. Bachmann | 9.3 | % | 8.9 | % | 10.3 | % | 20.0 | % |
| William Ordemann | 3.1 | % | 5.2 | % | 8.2 | % | -- | |

Equity Awards Outstanding at December 31, 2009

The following information summarizes each named executive officer's long-term incentive awards outstanding at December 31, 2009. We expect to be allocated our pro rata share of the expense associated with such awards under the ASA. As a result, the gross amounts listed in the tables do not represent the amount of expense we expect to recognize in connection with these awards.

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The following table presents information concerning each named executive officer's restricted unit and options awards outstanding at December 31, 2009. The referenced units in the table below are common units of Enterprise Products Partners.

| Name | Vesting Date | Option Awards: Number of Units Underlying Options Exercisable (#) | Option Awards: Number of Units Underlying Options Unexercisable (#) | Option Awards: Option Exercise Price ($/Unit) | Option Awards: Option Expiration Date | Unit Awards: Number of Units That Have Not Vested (#)(2) | Unit Awards: Market Value of Units That Have Not Vested ($)(3) |
|---|---|---|---|---|---|---|---|
| Restricted unit awards: | | | | | | | |
| Michael A. Creel (CEO) | Various (1) | -- | -- | -- | -- | 129,100 | $ 4,055,031 |
| W. Randall Fowler (CFO) | Various (1) | -- | -- | -- | -- | 91,100 | 2,861,451 |
| A. James Teague | Various (1) | -- | -- | -- | -- | 104,000 | 3,266,640 |
| Richard H. Bachmann | Various (1) | -- | -- | -- | -- | 104,000 | 3,266,640 |
| William Ordemann | Various (1) | -- | -- | -- | -- | 86,100 | 2,704,401 |
| Unit option awards: | | | | | | | |
| Michael A. Creel (CEO): | | | | | | | |
| August 4, 2005 option grant | 8/04/09 | 35,000 | -- | 26.47 | 8/04/15 | -- | -- |
| May 1, 2006 option grant | 5/01/10 | -- | 40,000 | 24.85 | 5/01/16 | -- | -- |
| May 29, 2007 option grant | 5/29/11 | -- | 60,000 | 30.96 | 12/31/12 | -- | -- |
| May 22, 2008 option grant | 5/22/12 | -- | 90,000 | 30.93 | 12/31/13 | -- | -- |
| February 19, 2009 option grant | 2/19/13 | -- | 75,000 | 22.06 | 12/31/14 | -- | -- |
| May 6, 2009 option grant | 5/06/13 | -- | 90,000 | 24.92 | 12/31/14 | -- | -- |
| W. Randall Fowler (CFO): | | | | | | | |
| August 4, 2005 option grant | 8/04/09 | 25,000 | -- | 26.47 | 8/04/15 | -- | -- |
| May 1, 2006 option grant | 5/01/10 | -- | 40,000 | 24.85 | 5/01/16 | -- | -- |
| May 29, 2007 option grant | 5/29/11 | -- | 45,000 | 30.96 | 12/31/12 | -- | -- |
| | 5/22/12 | -- | 60,000 | 30.93 | 12/31/13 | -- | -- |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| May 22, 2008 option grant | | | | | | | |
| February 19, 2009 option grant | 2/19/13 | -- | 52,500 | 22.06 | 12/31/14 | -- | -- |
| May 6, 2009 option grant | 5/06/13 | -- | 60,000 | 24.92 | 12/31/14 | -- | -- |
| A. James Teague: | | | | | | | |
| August 4, 2005 option grant | 8/04/09 | 35,000 | -- | 26.47 | 8/04/15 | -- | -- |
| May 1, 2006 option grant | 5/01/10 | -- | 40,000 | 24.85 | 5/01/16 | -- | -- |
| May 29, 2007 option grant | 5/29/11 | -- | 60,000 | 30.96 | 12/31/12 | -- | -- |
| May 22, 2008 option grant | 5/22/12 | -- | 60,000 | 30.93 | 12/31/13 | -- | -- |
| February 19, 2009 option grant | 2/19/13 | -- | 60,000 | 22.06 | 12/31/14 | -- | -- |
| May 6, 2009 option grant | 5/06/13 | -- | 60,000 | 24.92 | 12/31/14 | -- | -- |
| Richard H. Bachmann: | | | | | | | |
| August 4, 2005 option grant | 8/04/09 | 35,000 | -- | 26.47 | 8/04/15 | -- | -- |
| May 1, 2006 option grant | 5/01/10 | -- | 40,000 | 24.85 | 5/01/16 | -- | -- |
| May 29, 2007 option grant | 5/29/11 | -- | 60,000 | 30.96 | 12/31/12 | -- | -- |
| May 22, 2008 option grant | 5/22/12 | -- | 60,000 | 30.93 | 12/31/13 | -- | -- |
| February 19, 2009 option grant | 2/19/13 | -- | 60,000 | 22.06 | 12/31/14 | -- | -- |
| May 6, 2009 option grant | 5/06/13 | -- | 60,000 | 24.92 | 12/31/14 | -- | -- |
| William Ordemann: | | | | | | | |
| May 10, 2004 option grant | 5/10/08 | 25,000 | -- | 20.00 | 5/10/14 | -- | -- |
| August 4, 2005 option grant | 8/04/09 | 25,000 | -- | 26.47 | 8/04/15 | -- | -- |
| May 1, 2006 option grant | 5/01/10 | -- | 30,000 | 24.85 | 5/01/16 | -- | -- |
| May 29, 2007 option grant | 5/29/11 | -- | 30,000 | 30.96 | 12/31/12 | -- | -- |
| May 22, 2008 option grant | 5/22/12 | -- | 60,000 | 30.93 | 12/31/13 | -- | -- |
| February 19, 2009 option grant | 2/19/13 | -- | 45,000 | 22.06 | 12/31/14 | -- | -- |
| May 6, 2009 option grant | 5/06/13 | -- | 60,000 | 24.92 | 12/31/14 | -- | -- |

(1) Of the 514,300 restricted unit awards presented in the table, 55,200 vest in 2010, 117,300 vest in 2011, 152,400 vest in 2012 and 189,400 vest in 2013.
(2) Amounts represent the total number of restricted unit awards granted to each named executive officer.
(3) Amounts derived by multiplying the total number of restricted unit awards outstanding for each named executive officer by the closing price of our common units at December 31, 2009 of $31.41 per unit.

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The following table presents information concerning each named executive officer's nonvested profits interest awards at December 31, 2009:

| | | Option Awards | | | Unit Awards | |
|---|---|---|---|---|---|---|
| Name | Vesting Date (1) | Number of Units Underlying Options Unexercisable (#) | Option Exercise Price ($/Unit) | Option Expiration Date | Number of Units That Have Not Vested (#) | Market Value of Units That Have Not Vested ($) |
| EPE Unit I: | | | | | | |
| Michael A. Creel (CEO) | 8/23/10 | -- | -- | -- | -- | $1,651,767 |
| W. Randall Fowler (CFO) | 8/23/10 | -- | -- | -- | -- | 1,109,396 |
| A. James Teague | 8/23/10 | -- | -- | -- | -- | 1,109,396 |
| Richard H. Bachmann | 8/23/10 | -- | -- | -- | -- | 1,651,767 |
| William Ordemann | 8/23/10 | -- | -- | -- | -- | 554,698 |
| Enterprise Unit: | | | | | | |
| Michael A. Creel (CEO) | 2/20/14 | -- | -- | -- | -- | 1,178,753 |
| W. Randall Fowler (CFO) | 2/20/14 | -- | -- | -- | -- | 523,890 |
| A. James Teague | 2/20/14 | -- | -- | -- | -- | 654,863 |
| Richard H. Bachmann | 2/20/14 | -- | -- | -- | -- | 654,863 |
| William Ordemann | 2/20/14 | -- | -- | -- | -- | 523,890 |
| EPCO Unit: | | | | | | |
| Michael A. Creel (CEO) | 11/13/13 | -- | -- | -- | -- | 47,506 |
| W. Randall Fowler (CFO) | 11/13/13 | -- | -- | -- | -- | 47,506 |
| A. James Teague | 11/13/13 | -- | -- | -- | -- | 47,506 |
| Richard H. Bachmann | 11/13/13 | -- | -- | -- | -- | 47,506 |

(1) In December 2009, the partnership agreements of each Employee Partnership were amended to provide that the expected liquidation date for each Employee Partnership be extended to February 2016. The extensions of the expected liquidation dates are intended to align the interests of the employee partners of each Employee Partnership with the long-term interests of EPCO and other unitholders by providing an incentive to such employees to devote themselves to maximizing the value of the underlying publicly traded partnerships over an extended period of time.

The profits interest awards of the remaining Employee Partnerships had no market (or assumed liquidation) value at December 31, 2009 due to a decrease in the market value of the limited partner interests owned by each Employee Partnership since formation.

Option Exercises and Units Vested

The following table presents the exercise of unit options by and vesting of restricted units (in each case, including common units of Enterprise Products Partners, not Duncan Energy Partners) to our named executive officers during the year ended December 31, 2009 for which we were historically responsible for a share of the related expense of such awards.

| | Option Awards | | Unit Awards | |
|---|---|---|---|---|
| | Number of Units | Gross Value | Number of Units | Gross Value |

| Name | Acquired on Exercise (#) | Realized on Exercise ($) (1) | Acquired on Vesting (#) | Realized on Vesting ($) (2) |
|---|---|---|---|---|
| Michael A. Creel (CEO) | 35,000 | $330,400 | 10,000 | $280,500 |
| W. Randall Fowler (CFO) | 10,000 | 93,200 | 6,000 | 168,300 |
| A. James Teague | 35,000 | 326,200 | 10,000 | 280,500 |
| Richard H. Bachmann | 35,000 | 330,400 | 10,000 | 280,500 |
| William Ordemann | -- | -- | 16,000 | 451,900 |

(1) Amount determined by multiplying the number of units acquired on exercise of the options by the difference between the closing price of Enterprise Products Partners' common units on the date of exercise less the exercise price.
(2) Amount determined by multiplying the number of restricted unit awards that vested during 2009 by the closing price of Enterprise Products Partners' common units on the date of vesting.

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Compensation Committee Report

We do not have a separate compensation committee. In addition, we do not directly employ or compensate our named executive officers. Rather, under the ASA, we reimburse EPCO for the compensation of our executive officers. Accordingly, to the extent that decisions are made regarding the compensation policies pursuant to which our named executive officers are compensated, they are made by Mr. Duncan and EPCO alone (except for equity awards, as previously noted), and not by our Board.

In light of the foregoing, the Board has reviewed and discussed with management the Compensation Discussion and Analysis set forth above and determined that it be included in this annual report for the year ended December 31, 2009.

Submitted by: Dan L. Duncan
Michael A. Creel
E. William Barnett
Charles M. Rampacek
Rex C. Ross
Richard H. Bachmann
Ralph S. Cunningham
W. Randall Fowler
A. James Teague

Notwithstanding anything to the contrary set forth in any previous filings under the Securities Act, as amended, or the Exchange Act, as amended, that incorporate future filings, including this annual report, in whole or in part, the foregoing Compensation Committee Report shall not be incorporated by reference into any such filings.

Compensation Committee Interlocks and Insider Participation

None of the directors or executive officers of our general partner served as members of the compensation committee of another entity that has or had an executive officer who served as a member of our Board during 2009. As previously noted, we do not have a separate compensation committee. Mr. Duncan and EPCO alone make compensation policies (except for equity awards, as previously noted), and not our Board.

Director Compensation

Neither we nor EPGP provide any additional compensation to employees of EPCO who serve as directors of EPGP. The following table presents information regarding compensation to the independent directors of our general partner, Messrs. Barnett, Ross and Rampacek, during the year ended December 31, 2009.

| Name | Fees Earned or Paid in Cash ($) |
|---|---|
| E. William Barnett | $ 90,000 |
| Rex C. Ross | $ 75,000 |
| Charles M. Rampacek | $ 75,000 |

For 2009, the independent directors were compensated for their services as follows: (i) each received a $75,000 cash retainer annually and (ii) if the individual served as chairman of a committee of the Board, then he received an additional $15,000 in cash annually. Effective January 1, 2010, the annual compensation arrangements for our independent directors changed to the following:

§ Each independent director will receive $75,000 in cash annually;

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- § If the individual serves as chairman of a committee of the Board of Directors, then he will receive an additional $15,000 in cash annually;
- § Each independent director will receive a meeting fee of $1,500 in cash for each meeting of the Board attended. In addition, each independent director will receive a meeting fee of $1,500 in cash for each meeting of a duly appointed committee of the Board attended, provided that he is duly elected or appointed to the committee; and
- § Each independent director shall receive an annual grant of our common units having a fair market value, based on the closing price of our common units on the trading day immediately preceding the date of grant, of $75,000.

## Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters.

### Security Ownership of Certain Beneficial Owners

The following table sets forth certain information as of February 1, 2010, regarding each person known by our general partner to beneficially own more than 5% of our common units:

| Title of Class | Name and Address of Beneficial Owner | Amount and Nature of Beneficial Ownership | Percent of Class |
|---|---|---|---|
| Common units | Dan L. Duncan | 186,843,182 (1) | 30.8% |
| | 1100 Louisiana Street, 10th Floor | | |
| | Houston, Texas 77002 | | |
| | | | |
| Class B units | Dan L. Duncan | 4,520,431 | 100% |
| | 1100 Louisiana Street, 10th Floor | | |
| | Houston, Texas 77002 | | |

(1) For a detailed listing of ownership amounts that comprise Mr. Duncan's total beneficial ownership of our common units, see the table presented in the following section, "Security Ownership of Management," within this Item 12.

### Security Ownership of Management

Enterprise Products Partners L.P. and Enterprise GP Holdings L.P.

The following table sets forth certain information regarding the beneficial ownership of our common units and the units of Enterprise GP Holdings as of February 1, 2010 by (i) our named executive officers; (ii) the current directors of EPGP; and (iii) the current directors and executive officers of EPGP as a group. Enterprise GP Holdings owns 100% of the membership interests of our general partner, EPGP.

All information with respect to beneficial ownership has been furnished by the respective directors or officers. Each person has sole voting and dispositive power over the securities shown unless otherwise indicated below. The beneficial ownership amounts of certain individuals include options to acquire our common units that are exercisable within 60 days of the filing date of this annual report.

Mr. Duncan owns 50.4% of the voting stock of EPCO and, accordingly, exercises sole voting and dispositive power with respect to our common units beneficially owned by EPCO and its affiliates. The remaining shares of EPCO capital stock are owned primarily by trusts for the benefit of members of Mr. Duncan's family. The address of EPCO is 1100 Louisiana Street, 10th Floor, Houston, Texas 77002.

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| Name of Beneficial Owner | Enterprise Products Partners L.P. Common Units Amount and Nature of Beneficial Ownership | Percent of Class | | Enterprise GP Holdings L.P. Units Amount and Nature of Beneficial Ownership | Percent of Class | |
|---|---|---|---|---|---|---|
| Dan L. Duncan: | | | | | | |
| Units owned by EPCO: | | | | | | |
| Through DFI Delaware Holdings, L.P. | 130,506,142 | 21.5 | % | -- | -- | |
| Through Duncan Family Interests, Inc. | 6,775,839 | 1.1 | % | 71,860,405 | 51.6 | % |
| Through DFI GP Holdings L.P. | 3,100,000 | * | | 25,162,804 | 18.1 | % |
| Through Enterprise GP Holdings L.P. | 21,167,783 | 3.5 | % | -- | -- | |
| Through EPCO Holdings, Inc. | 6,182,354 | 1.0 | % | 75,865 | * | |
| Units owned by DD Securities LLC | 1,392,686 | * | | 3,745,673 | 2.7 | % |
| Units owned by Employee Partnerships (1) | 1,623,654 | * | | 7,165,315 | 5.1 | % |
| Units owned by family trusts (2) | 14,624,718 | 2.4 | % | 243,071 | * | |
| Units owned personally | 1,470,006 | * | | 250,000 | * | |
| Total for Dan L. Duncan | 186,843,182 | 30.8 | % | 108,503,133 | 78.0 | % |
| | | | | | | |
| Michael A. Creel (3,4) | 248,868 | * | | 35,000 | * | |
| W. Randall Fowler (3,5) | 153,674 | * | | 3,000 | * | |
| Richard H. Bachmann (3,6) | 233,238 | * | | 18,969 | * | |
| A. James Teague (3,7) | 295,228 | * | | 17,000 | * | |
| William Ordemann (3) | 117,119 | * | | 3,120 | * | |
| Dr. Ralph S. Cunningham | 104,739 | * | | 4,000 | * | |
| E. William Barnett | 2,154 | * | | 9,000 | * | |
| Rex C. Ross | 48,625 | * | | 6,048 | * | |
| Charles M. Rampacek | 9,615 | * | | -- | -- | |
| All current directors and executive officers of EPGP, as a group (16 individuals in total) (8) | 188,497,607 | 31.1 | % | 108,631,570 | 78.0 | % |

* The beneficial ownership of each individual is less than 1% of the registrant's common units outstanding.

(1) As a result of EPCO's ownership of the general partners of the Employee Partnerships, Mr. Duncan is deemed beneficial owner of the limited partner interests held by these entities.

(2) Mr. Duncan is deemed beneficial owner of the limited partner interests held by certain family trusts, the beneficiaries of which are shareholders of EPCO.

(3) These individuals are named executive officers for 2009.

(4) The number of Enterprise Products Partners' common units presented for Mr. Creel includes 35,000 common unit options that are exercisable within 60 days of the filing date of this report.

(5) The number of Enterprise Products Partners' common units presented for Mr. Fowler includes 25,000 common unit options that are exercisable within 60 days of the filing date of this report.

(6) The number of Enterprise Products Partners' common units presented for Mr. Bachmann includes 35,000 common unit options that are exercisable within 60 days of the filing date of this report.

(7) The number of Enterprise Products Partners' common units presented for Mr. Teague includes 35,000 common unit options that are exercisable within 60 days of the filing date of this report.

(8) Cumulatively, this group's beneficial ownership amount includes 220,000 options to acquire our common units that were issued under the 1998 Plan. These options vested in prior periods and remain exercisable within 60 days

of the filing date of this annual report.

Essentially all of the ownership interests in us and Enterprise GP Holdings that are owned or controlled by EPCO are pledged as security under the credit facility of an EPCO affiliate. This credit facility contains customary and other events of default relating to EPCO and certain of its affiliates, including Enterprise GP Holdings and us. In the event of a default under this credit facility, a change in control of Enterprise GP Holdings or us could occur, including a change in control of our respective general partners.

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Duncan Energy Partners L.P.

The following table presents the beneficial ownership of common units of Duncan Energy Partners by our directors, named executive officers and all directors and officers of our general partner (as a group) at February 1, 2010. As of February 1, 2010, Enterprise Products Partners owned 100% of the membership interests of EPO, which directly owns 100% of the membership interests of DEP GP and indirectly owns 58.6% of Duncan Energy Partners' common units through a subsidiary.

| | Duncan Energy Partners L.P. Common Units | | |
|---|---|---|---|
| Name of Beneficial Owner | Amount and Nature of Beneficial Ownership | Percent of Class | |
| Dan L. Duncan: | | | |
| Units owned by EPCO Holdings, Inc. | 99,453 | * | |
| Units owned by EPO | 33,783,587 | 58.6 | % |
| Units owned by DD Securities LLC | 103,100 | * | |
| Units owned personally | 382,500 | * | |
| Total for Dan L. Duncan | 34,368,640 | 59.6 | % |
| | | | |
| Michael A. Creel (1) | 7,500 | * | |
| W. Randall Fowler (1,2) | 2,000 | * | |
| Richard H. Bachmann (1,3) | 14,172 | * | |
| A. James Teague (1) | 6,000 | * | |
| William Ordemann (1) | 3,810 | * | |
| Dr. Ralph S. Cunningham | 3,000 | * | |
| All current directors and executive officers of EPGP, as a group (16 individuals in total) | 34,435,712 | 59.7 | % |

* The beneficial ownership of each individual is less than 1% of the registrant's units outstanding.
(1) These individuals are named executive officers for 2009.
(2) Mr. Fowler is the CFO of Duncan Energy Partners.
(3) Mr. Bachmann is the CEO of Duncan Energy Partners.

Equity Ownership Guidelines

On December 31, 2009, the ACG Committee recommended to the Board, and effective on January 1, 2010, the Board adopted and approved, new equity ownership guidelines for our general partner's directors and executive officers in order to further align their interests and actions with the interests of our general partner, us and our unitholders. Under the new guidelines:

§ each non-management director of our general partner is required to own our common units having an aggregate value (as defined in the guidelines) of three times the dollar amount of such non-management director's aggregate annual cash retainer for service on the Board paid for the most recently completed calendar year; and

§ each executive officer of our general partner is required to own our common units having an aggregate value (as defined in the guidelines) of three times the dollar amount of such executive officer's aggregate annual base salary for the most recently completed calendar year; provided, however, that the value of any units representing limited partnership interests in Duncan Energy Partners or Enterprise GP Holdings (each of which we refer to as an "Affiliated MLP"), owned by an executive officer of our general partner who is also an executive officer of the general partner of such Affiliated MLP, shall be counted toward the equity ownership requirements set forth above.

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Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2009 regarding the long-term incentive plans of EPCO under which our common units are authorized for issuance. For additional information regarding our equity-based compensation, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

| Plan Category | Number of Units to Be Issued Upon Exercise of Outstanding Common Unit Options (a) | Weighted-Average Exercise Price of Outstanding Common Unit Options (b) | Number of Units Remaining Available For Future Issuance Under Equity Compensation Plans (excluding securities reflected in column (a) (c) |
|---|---|---|---|
| Equity compensation plans approved by unitholders: | | | |
| 1998 Plan (1) | 1,572,500 | $ 27.30 | 652,543 |
| 2006 Plan (2) | 118,420 | $ 26.11 | n/a |
| 2008 Plan (3) | 2,135,000 | $ 25.97 | 7,865,000 |
| Equity compensation plans not approved by unitholders: | | | |
| None | -- | -- | -- |
| Total for equity compensation plans | 3,825,920 | $ 26.52 | 8,517,543 |

(1) Of the 1,572,500 unit options outstanding at December 31, 2009, 447,500 were immediately exercisable, an additional 410,000, 685,000 and 30,000 options are exercisable in 2010, 2012 and 2013, respectively.
(2) No additional awards are expected to be issued under the 2006 Plan.
(3) Of the 2,135,000 unit options outstanding at December 31, 2009, 705,000 are exercisable in 2013 and 1,430,000 are exercisable in 2014.

The 1998 Plan provides for awards of our common units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under the 1998 Plan may be granted in the form of unit options, restricted units, phantom units, UARs and DERs. Up to 7,000,000 of our common units may be issued as awards under the 1998 Plan.

The 2006 Plan currently provides for awards of our common units (formerly of TEPPCO units) and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under the 2006 Plan may be granted in the form of unit options, restricted units, phantom units, UARs and DERs. Effective upon the consummation of the TEPPCO Merger, we assumed the vested and unvested options, restricted units and UAR awards outstanding on October 26, 2009 under the 2006 Plan and converted them into our options, restricted units and UAR awards based on the TEPPCO Merger exchange ratio. The vesting terms of each award and other provisions of the plan remain unchanged. We do not expect to issue additional awards under the 2006 Plan in the future.

The 2008 Plan provides for awards of our common units and other rights to our non-employee directors and to consultants and employees of EPCO and its affiliates providing services to us. Awards under the 2008 Plan may be granted in the form of unit options, restricted units, phantom units, UARs and DERs. Up to 10,000,000 of our common units may be issued as awards under the 2008 Plan.

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Item 13. Certain Relationships and Related Transactions, and Director Independence.

Certain Relationships and Related Transactions

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties. Additional information regarding our related party transactions is set forth in Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report and incorporated by reference into this Item 13.

Review and Approval of Transactions with Related Parties

We generally consider transactions between us and our subsidiaries, on the one hand, and our executive officers and directors (or their immediate family members), our general partner or its affiliates (including companies owned or controlled by Mr. Duncan such as EPCO), on the other hand, to be related party transactions. As further described below, our partnership agreement sets forth procedures by which related party transactions and conflicts of interest may be approved or resolved by the general partner or the ACG Committee. In addition, our ACG Committee Charter, our general partner's written internal review and approval policies and procedures, or "management authorization policy," and the amended and restated ASA with EPCO govern specified related party transactions, as further described below.

The ACG Committee Charter provides that the ACG Committee is established to review and approve related party transactions:

§ for which Board approval is required by our management authorization policy, as such policy may be amended from time to time;

§ where an officer or director of the general partner or any of our subsidiaries is a party, without regard to the size of the transaction;

§ when requested to do so by management or the Board; or

§ pursuant to our partnership agreement or the limited liability company agreement of the general partner, as such agreements may be amended from time to time.

As discussed in more detail in "Partnership Management," "Corporate Governance" and "ACG Committee" within Item 10 of this annual report, the ACG Committee is comprised of three directors: Rex C. Ross, Charles M. Rampacek and E. William Barnett. During the year ended December 31, 2009, the ACG Committee reviewed and approved each of the following related party transactions:

§ Duncan Energy Partners' June 2009 repurchase from EPO of 8,943,400 Duncan Energy Partners common units in connection with the transactions described in "Liquidity and Capital Resources – Registration Statements" included under Item 7 of this annual report;

§ the TEPPCO Merger; and

§ our September 2009 issuance and sale of 5,940,594 of our common units in a private placement to EPCO Holdings, Inc., a privately held affiliate controlled by Dan L. Duncan, for $150.0 million (as more fully described in "Recent Sales of Unregistered Securities" included under Item 5 of this annual report).

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Our management authorization policy currently requires board approval for the following types of transactions to the extent such transactions have a value in excess of $100.0 million (thus triggering ACG Committee review under our ACG Committee Charter if such transaction is also a related party transaction):

§ asset purchase or sale transactions;

§ capital expenditures; and

§ purchase orders and operating and administrative expenses not governed by the ASA.

The ASA governs numerous day-to-day transactions between us and our subsidiaries, our general partner and EPCO and its affiliates, including the provision by EPCO of administrative and other services to us and our subsidiaries and our reimbursement of costs, without markup or discount, for those services. The ACG Committee reviewed and recommended the ASA, and the Board approved it upon receiving such recommendation. For a summary of the ASA, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Related party transactions that do not occur under the ASA and that are not reviewed by the ACG Committee, as described above, are subject to the management authorization policy. This policy, which applies to related party transactions as well as transactions with unrelated parties, specifies thresholds for our general partner's officers and chairman of the Board to authorize various categories of transactions, including purchases and sales of assets, expenditures, commercial and financial transactions and legal agreements.

Business Opportunity Agreements

The ASA also addresses potential conflicts that may arise among Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), and the EPCO Group with respect to business opportunities with third parties. The EPCO Group includes EPCO and its other affiliates, but excludes Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners and their respective general partners. With respect to potential conflicts regarding third-party business opportunities, the ASA provides, among other things, that:

§ If a business opportunity to acquire "equity securities" (as defined below) is presented to the EPCO Group, or to Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), or Duncan Energy Partners (including DEP GP), then Enterprise GP Holdings will have the first right to pursue such opportunity. The term "equity securities" is defined to include:

§ general partner interests (or securities which have characteristics similar to general partner interests) or interests in "persons" that own or control such general partner or similar interests (collectively, "GP Interests") and securities convertible, exercisable, exchangeable or otherwise representing ownership or control of such GP Interests; and

§ incentive distribution rights ("IDRs") and limited partner interests (or securities which have characteristics similar to IDRs or limited partner interests) in publicly traded partnerships or interests in "persons" that own or control such limited partner or similar interests (collectively, "non-GP Interests"); provided that such non-GP Interests are associated with GP Interests and are owned by the owners of GP Interests or their respective affiliates.

Enterprise GP Holdings will be presumed to want to acquire the equity securities until such time as EPE Holdings advises the EPCO Group, EPGP and DEP GP that it has abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to equal or exceed $100.0 million, the decision to decline the acquisition will be made by the CEO of EPE Holdings after consultation with and subject to the approval of the ACG

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Committee of EPE Holdings. If the purchase price is reasonably likely to be less than $100.0 million, the CEO of EPE Holdings may make the determination to decline the acquisition without consulting the ACG Committee of EPE Holdings.

In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group, and EPGP and DEP GP, then Enterprise Products Partners will have the second right to pursue such acquisition. Enterprise Products Partners will be presumed to want to acquire the equity securities until such time as EPGP advises the EPCO Group and DEP GP that Enterprise Products Partners has abandoned the pursuit of such acquisition. In determining whether or not to pursue the acquisition, Enterprise Products Partners will follow the same procedures applicable to Enterprise GP Holdings, as described above but utilizing EPGP's CEO and ACG Committee.

In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

§ If any business opportunity not covered by the preceding bullet point (i.e., not involving equity securities) is presented to the EPCO Group, or to Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), or Duncan Energy Partners (including DEP GP), Enterprise Products Partners will have the first right to pursue such opportunity either for itself or, if desired by Enterprise Products Partners in its sole discretion, for the benefit of Duncan Energy Partners. It will be presumed that Enterprise Products Partners will pursue the business opportunity until such time as its general partner advises the EPCO Group, EPE Holdings and DEP GP that it has abandoned the pursuit of such business opportunity.

In the event the purchase price or cost associated with the business opportunity is reasonably likely to equal or exceed $100.0 million, any decision to decline the business opportunity will be made by the CEO of EPGP after consultation with and subject to the approval of the ACG Committee of EPGP. If the purchase price or cost is reasonably likely to be less than $100.0 million, the CEO of EPGP may make the determination to decline the business opportunity without consulting EPGP's ACG Committee.

In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

In the event that Enterprise Products Partners abandons the business opportunity for itself and Duncan Energy Partners and so notifies the EPCO Group, EPE Holdings and DEP GP, Enterprise GP Holdings will have the second right to pursue such business opportunity. It will be presumed that Enterprise GP Holdings will pursue such acquisition until such time as its general partner declines such opportunity (in accordance with the procedures described above for Enterprise Products Partners) and advises the EPCO Group that it has abandoned the pursuit of such business opportunity.

Partnership Agreement Standards for ACG Committee Review

Under our partnership agreement, whenever a potential conflict of interest exists or arises between our general partner or any of its affiliates and us, any of our subsidiaries or any partner, any resolution or course of action by our general partner or its affiliates in respect to such conflict of interest is permitted and deemed approved by all of our partners, and will not constitute a breach of our partnership agreement or any agreement contemplated by such agreement, or of any duty stated or implied by law or equity, if the resolution or course of action is or, by operation of the partnership agreement is deemed to be, fair and reasonable to us; provided that, any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to us if such conflict of interest or resolution is (i) approved by a majority of the members of our general partner's ACG Committee ("Special Approval") or (ii) on terms

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objectively demonstrable to be no less favorable to us than those generally being provided to or available from unrelated third parties.

The ACG Committee (in connection with Special Approval) is authorized in connection with its resolution of any conflict of interest to consider:

§ the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;

§ the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us);

§ any customary or accepted industry practices and any customary or historical dealings with a particular person;

§ any applicable generally accepted accounting or engineering practices or principles;

§ the relative cost of capital of the parties and the consequent rates of return to the equity holders of the parties; and

§ such additional factors as the committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

The review and approval process of the ACG Committee, including factual matters that may be considered in determining whether a transaction is fair and reasonable, is generally governed by Section 7.9 of our partnership agreement. As discussed above, the ACG Committee's Special Approval is conclusively deemed fair and reasonable to us under the partnership agreement.

The review and work performed by the ACG Committee with respect to a transaction varies depending upon the nature of the transaction and the scope of the ACG Committee's charge. Examples of functions the ACG Committee may, as it deems appropriate, perform in the course of reviewing a transaction include (but are not limited to):

§ assessing the business rationale for the transaction;

§ reviewing the terms and conditions of the proposed transaction, including consideration and financing requirements, if any;

§ assessing the effect of the transaction on our earnings and distributable cash flow per unit, and on our results of operations, financial condition, properties or prospects;

§ conducting due diligence, including by interviews and discussions with management and other representatives and by reviewing transaction materials and findings of management and other representatives;

§ considering the relative advantages and disadvantages of the transactions to the parties;

§ engaging third-party financial advisors to provide financial advice and assistance, including by providing fairness opinions if requested;

§ engaging legal advisors; and

§

evaluating and negotiating the transaction and recommending for approval or approving the transaction, as the case may be.

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Nothing contained in the partnership agreement requires the ACG Committee to consider the interests of any person other than the partnership. In the absence of bad faith by the ACG Committee or our general partner, the resolution, action or terms so made, taken or provided (including granting Special Approval) by the ACG Committee or our general partner with respect to such matter are conclusive and binding on all persons (including all of our partners) and do not constitute a breach of the partnership agreement, or any other agreement contemplated thereby, or a breach of any standard of care or duty imposed in the partnership agreement or under the Delaware Revised Uniform Limited Partnership Act or any other law, rule or regulation. The partnership agreement provides that it is presumed that the resolution, action or terms made, taken or provided by the ACG Committee or our general partner were not made, taken or provided in bad faith, and in any proceeding brought by any limited partner or by or on behalf of such limited partner or any other limited partner or us challenging such resolution, action or terms, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Director Independence

Messrs. Barnett, Ross and Rampacek have been determined to be independent under the applicable NYSE listing standards and are independent under the rules of the SEC applicable to audit committees. For a discussion of independence standards applicable to the Board and factors considered by the Board in making its independence determinations, please refer to "Corporate Governance" and "ACG Committee" under Item 10 of this annual report.

## Item 14. Principal Accountant Fees and Services.

We have engaged Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, "Deloitte & Touche") as our independent registered public accounting firm and principal accountants. The following table summarizes fees we paid Deloitte & Touche for independent auditing, tax and related services for each of the last two fiscal years (dollars in millions):

| | For Year Ended December 31, | |
|---|---|---|
| | 2009 | 2008 |
| Audit Fees (1) | $5.4 | $5.4 |
| Audit-Related Fees (2) | -- | -- |
| Tax Fees (3) | -- | 0.6 |
| All Other Fees (4) | N/A | N/A |

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the audit of our annual financial statements and internal controls over financial reporting, (ii) the review of our quarterly financial statements or (iii) those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this annual report.
(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews. This category primarily includes services relating to internal control assessments and accounting-related consulting.
(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice and tax planning. This category primarily includes services relating to the preparation of unitholder annual K-1 statements and partnership tax planning. In 2008, PricewaterhouseCoopers International Limited was engaged to perform the majority of tax related services.
(4) All other fees represent amounts we were billed in each of the years presented for services not classifiable under the other categories listed in the table above. No such services were rendered by Deloitte & Touche during the last

two years.

The ACG Committee of our general partner has approved the use of Deloitte & Touche as our independent principal accountant.  In connection with its oversight responsibilities, the ACG Committee

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has adopted a pre-approval policy regarding any services proposed to be performed by Deloitte & Touche. The pre-approval policy includes four primary service categories: Audit, Audit-related, Tax and Other.

In general, as services are required, management and Deloitte & Touche submit a detailed proposal to the ACG Committee discussing the reasons for the request, the scope of work to be performed, and an estimate of the fee to be charged by Deloitte & Touche for such work. The ACG Committee discusses the request with management and Deloitte & Touche, and if the work is deemed necessary and appropriate for Deloitte & Touche to perform, approves the request subject to the fee amount presented (the initial "pre-approved" fee amount). As part of these discussions, the ACG Committee must determine whether or not the proposed services are permitted under the rules and regulations concerning auditor independence under the Sarbanes-Oxley Act of 2002 as well as rules of the American Institute of Certified Public Accountants. If at a later date, it appears that the initial pre-approved fee amount may be insufficient to complete the work, then management and Deloitte & Touche must present a request to the ACG Committee to increase the approved amount and the reasons for the increase.

Under the pre-approval policy, management cannot act upon its own to authorize an expenditure for services outside of the pre-approved amounts. On a quarterly basis, the ACG Committee is provided a schedule showing Deloitte & Touche's pre-approved amounts compared to actual fees billed for each of the primary service categories. The ACG Committee's pre-approval process helps to ensure the independence of our principal accountant from management.

In order for Deloitte & Touche to maintain its independence, we are prohibited from using them to perform general bookkeeping, management or human resource functions, and any other service not permitted by the Public Company Accounting Oversight Board. The ACG Committee's pre-approval policy also precludes Deloitte & Touche from performing any of these services for us.

## PART IV

Item 15. Exhibits and Financial Statement Schedules.

(a) The following documents are filed as a part of this annual report:

(1) Financial Statements: See Index to Consolidated Financial Statements on page F-1 of this annual report for financial statements filed as part of this annual report.

(2) Financial Statement Schedules: All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(3) Exhibits.

| Exhibit Number | Exhibit* |
|---|---|
| 2.1 | Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003). |
| 2.2 | Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and |

| | |
|---|---|
| | GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004). |
| 2.3 | Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003). |

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|---|---|
| 2.4 | Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 21, 2004). |
| 2.5 | Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003). |
| 2.6 | Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub B LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed June 29, 2009). |
| 2.7 | Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub A LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 29, 2009). |
| 3.1 | Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 9, 2007). |
| 3.2 | Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated August 8, 2005 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 10, 2005). |
| 3.3 | Amendment No. 1 to Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated December 27, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K/A filed January 3, 2008). |
| 3.4 | Amendment No. 2 to Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated April 14, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 16, 2008). |
| 3.5 | Amendment No. 3 to Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated November 6, 2008 (incorporated by reference to Exhibit 3.5 to Form 10-Q filed November 10, 2008). |
| 3.6 | Amendment No. 4 to Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated October 26, 2009 (incorporated by reference to Exhibit 3.1 to Form 8-K filed October 28, 2009). |
| 3.7 | Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated November 7, 2007 (incorporated by reference to Exhibit 3.2 to Form 10-Q filed November 9, 2007). |
| 3.8 | First Amendment to Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated November 6, 2008 (incorporated by reference to Exhibit 3.7 to Form 10-Q filed November 10, 2008). |

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| 3.9 | Company Agreement of Enterprise Products Operating LLC dated June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 8, 2007). |
| 3.10 | Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004). |
| 3.11 | Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004). |
| 4.1 | Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Form S-1A Registration Statement, Reg. No. 333-52537, filed July 21, 1998). |
| 4.2 | Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000). |
| 4.3 | First Supplemental Indenture, dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration |

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| | Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003). |
| 4.4 | Second Supplemental Indenture, dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003). |
| 4.5 | Third Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed August 8, 2007). |
| 4.6 | Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 6, 2004). |
| 4.7 | First Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 6, 2004). |
| 4.8 | Second Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 6, 2004). |
| 4.9 | Third Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 6, 2004). |
| 4.10 | Fourth Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 6, 2004). |
| 4.11 | Fifth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 3, 2005). |
| 4.12 | Sixth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 3, 2005). |
| 4.13 | Seventh Supplemental Indenture, dated as of June 1, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.46 to Form 10-Q filed November 4, 2005). |
| 4.14 | Eighth Supplemental Indenture, dated as of July 18, 2006, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006). |

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| 4.15 | Ninth Supplemental Indenture, dated as of May 24, 2007, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed May 24, 2007). |
| 4.16 | Tenth Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007). |
| 4.17 | Eleventh Supplemental Indenture, dated as of September 4, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form |

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| | 8-K filed September 5, 2007). |
| 4.18 | Twelfth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008). |
| 4.19 | Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008). |
| 4.20 | Fourteenth Supplemental Indenture, dated as of December 8, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008). |
| 4.21 | Fifteenth Supplemental Indenture, dated as of June 10, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009). |
| 4.22 | Sixteenth Supplemental Indenture, dated as of October 5, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009). |
| 4.23 | Seventeenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 28, 2009). |
| 4.24 | Eighteenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 28, 2009). |
| 4.25 | Global Note representing $350.0 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003). |
| 4.26 | Global Note representing $499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 10-K filed March 31, 2003). |
| 4.27 | Global Notes representing $450.0 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001). |
| 4.28 | Global Note representing $500.0 million principal amount of 4.00% Series B Senior Notes due 2007 with attached Guarantee (incorporated by reference to Exhibit 4.14 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005). |

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| 4.29 | Global Note representing $500.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005). |
| 4.30 | Global Note representing $150.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005). |
| 4.31 | Global Note representing $350.0 million principal amount of 6.65% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005). |
| 4.32 | Global Note representing $500.0 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.27 to Form 10-K filed March 15, 2005). |
| 4.33 | Global Note representing $250.0 million principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed November 4, 2005). |
| 4.34 | Global Note representing $250.0 million principal amount of 5.75% Series B Senior Notes due |

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| | 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed November 4, 2005). |
| 4.35 | Global Note representing $500.0 million principal amount of 4.95% Senior Notes due 2010 with attached Guarantee (incorporated by reference to Exhibit 4.47 to Form 10-Q filed November 4, 2005). |
| 4.36 | Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006). |
| 4.37 | Global Note representing $800.0 million principal amount of 6.30% Senior Notes due 2017 with attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 9, 2007). |
| 4.38 | Form of Global Note representing $400.0 million principal amount of 5.65% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008). |
| 4.39 | Form of Global Note representing $700.0 million principal amount of 6.50% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008). |
| 4.40 | Form of Global Note representing $500.0 million principal amount of 9.75% Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008). |
| 4.41 | Form of Global Note representing $500.0 million principal amount of 4.60% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009). |
| 4.42 | Form of Global Note representing $500.0 million principal amount of 5.25% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009). |
| 4.43 | Form of Global Note representing $600.0 million principal amount of 6.125% Senior Notes due 2039 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009). |
| 4.44 | Form of Global Note representing $490.5 million principal amount of 7.625% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 28, 2009). |
| 4.45 | Form of Global Note representing $182.6 million principal amount of 6.125% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 28, 2009). |
| 4.46 | Form of Global Note representing $237.6 million principal amount of 5.90% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 28, 2009). |
| 4.47 | Form of Global Note representing $349.7 million principal amount of 6.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 8-K filed October 28, 2009). |
| 4.48 | Form of Global Note representing $399.6 million principal amount of 7.55% Senior Notes due 2038 with attached Guarantee (incorporated by reference to Exhibit 4.7 to Form 8-K filed October 28, 2009). |
| 4.49 | Form of Global Note representing $285.8 million principal amount of 7.000% Junior Subordinated Notes due 2067 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 8-K filed October 28, 2009). |
| 4.50 | Replacement Capital Covenant, dated May 24, 2007, executed by Enterprise Products Operating L.P. and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to |

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| | Exhibit 99.1 to Form 8-K filed May 24, 2007). |
| 4.51 | First Amendment to Replacement Capital Covenant dated August 25, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.2 to Form 8-K filed August 25, 2006). |
| 4.52 | Purchase Agreement, dated as of July 12, 2006 between Cerrito Gathering Company, Ltd., Cerrito Gas Marketing, Ltd., Encinal Gathering, Ltd., as Sellers, Lewis Energy Group, L.P. as Guarantor, and Enterprise Products Partners L.P., as Buyer (incorporated by reference to Exhibit 4.6 to Form 10-Q filed August 8, 2006). |

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| 4.53 | Replacement Capital Covenant, dated October 27, 2009, among Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.9 to Form 8-K filed October 28, 2009). |
| 4.54 | Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.2 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002). |
| 4.55 | First Supplemental Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.3 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002). |
| 4.56 | Second Supplemental Indenture, dated June 27, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.6 to the Form 10-Q filed by TEPPCO Partners, L.P. on August 14, 2002). |
| 4.57 | Third Supplemental Indenture, dated January 20, 2003, by and among TEPPCO Partners, L.P. as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. as Subsidiary Guarantors, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.7 to the Form 10-K filed by TEPPCO Partners, L.P. on March 21, 2003). |
| 4.58 | Full Release of Guarantee, dated July 31, 2006, by Wachovia Bank, National Association, as Trustee, in favor of Jonah Gas Gathering Company (incorporated by reference to Exhibit 4.8 to the Form 10-Q filed by TEPPCO Partners, L.P. on November 7, 2006). |
| 4.59 | Fourth Supplemental Indenture, dated June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Val Verde Gas Gathering Company, L.P., TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007). |
| 4.60 | Fifth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.11 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008). |
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| | Sixth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.12 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008). |
| 4.62 | Seventh Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.13 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008). |
| 4.63 | Eighth Supplemental Indenture, dated October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009). |
| 4.64# | Full Release of Guarantee, dated November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, |

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| | L.P. by U.S. Bank National Association, as Trustee. |
| 4.65 | Indenture, dated May 14, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 99.1 of the Form 8-K filed by TEPPCO Partners, L.P. on May 15, 2007). |
| 4.66 | First Supplemental Indenture, dated May 18, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on May 18, 2007). |
| 4.67 | Replacement of Capital Covenant, dated May 18, 2007, executed by TEPPCO Partners, L.P., TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P. in favor of the covered debt holders described therein (incorporated by reference to Exhibit 99.1 to the Form 8-K of TEPPCO Partners, L.P. on May 18, 2007). |
| 4.68 | Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007). |
| 4.69 | Third Supplemental Indenture, dated as of October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009). |
| 4.70# | Full Release of Guarantee, dated as of November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by The Bank of New York Mellon Trust Company, N.A., as Trustee. |
| 10.1 | Transportation Contract between Enterprise Products Operating L.P. and Enterprise Transportation Company dated June 1, 1998 (incorporated by reference to Exhibit 10.3 to Form S-1/A Registration Statement, Reg. No. 333-52537, filed July 8, 1998). |
| 10.2*** | Enterprise Products 1998 Long-Term Incentive Plan (Amended and Restated as of February 23, 2010) (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 26, 2010). |
| 10.3*** | Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before May 7, 2008 (incorporated by reference to Exhibit 10.2 to Form 10-Q filed November 8, 2007). |
| 10.4*** | Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued on or after May 7, 2008 but before February 23, 2010 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed May 12, 2008). |
| 10.5*** | Amendment to Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.2 to Form 8-K filed February 26, 2010). |
| 10.6*** | Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed February 26, 2010). |
| 10.7*** | Form of Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.3 to Form 10-Q filed November 9, 2007). |

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| 10.8*** | Amendment to Form of Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.4 to Form 8-K filed February 26, 2010). |
| 10.9*** | Form of Employee Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Form 8-K filed February 26, 2010). |
| 10.10*** | Form of Non-Employee Director Restricted Unit Grant Award under the Enterprise Products |

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| | 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.6 to Form 8-K filed February 26, 2010). |
| 10.11*** | Enterprise Products Company 2005 EPE Long-Term Incentive Plan (amended and restated as of February 23, 2010) (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010). |
| 10.12*** | Form of Unit Appreciation Right Grant Award (Enterprise Products GP, LLC Directors) under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise GP Holdings on May 8, 2006). |
| 10.13*** | Form of Employee Restricted Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010). |
| 10.14*** | Form of Non-Employee Director Restricted Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010). |
| 10.15*** | Form of Phantom Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010). |
| 10.16*** | Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (February 23, 2010) (incorporated by reference to Exhibit 10.7 to Form 8-K filed February 26, 2010). |
| 10.17*** | Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 4.3 to Form S-8 filed May 6, 2008). |
| 10.18*** | Amendment to Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.8 to Form 8-K filed February 26, 2010). |
| 10.19*** | Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.9 to Form 8-K filed February 26, 2010). |
| 10.20*** | Form of Employee Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.10 to Form 8-K filed February 26, 2010). |
| 10.21*** | Form of Non-Employee Director Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.11 to Form 8-K filed February 26, 2010). |
| 10.22*** | 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (Amended and Restated February 23, 2010) (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Duncan Energy Partners L.P. on February 26, 2010). |
| 10.23*** | Form of Option Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Duncan Energy Partners L.P. on February 26, 2010). |
| 10.24*** | Form of Employee Restricted Unit Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Duncan Energy Partners L.P. on February 26, 2010). |
| 10.25*** | Form of Non-Employee Director Restricted Unit Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Form 8-K filed by Duncan Energy Partners L.P. on February 26, 2010). |
| 10.26*** | Agreement of Limited Partnership of EPE Unit L.P. dated August 23, 2005 (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Enterprise GP Holdings L.P. on September 1, 2005). |
| 10.27*** | First Amendment to Agreement of Limited Partnership of EPE Unit L.P. dated August 7, 2007 (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by Duncan Energy Partners L.P. on |

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| | August 8, 2007). |
| 10.28*** | Second Amendment to Agreement of Limited Partnership of EPE Unit L.P. dated July 1, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008). |
| 10.29*** | Third Amendment to Agreement of Limited Partnership of EPE Unit L.P. dated December 2, |

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| | 2009 (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise GP Holdings L.P. on December 8, 2009). |
| 10.30*** | Agreement of Limited Partnership of EPE Unit II, L.P. dated December 5, 2006 (incorporated by reference to Exhibit 10.13 to Form 10-K filed February 28, 2007). |
| 10.31*** | First Amendment to Agreement of Limited Partnership of EPE Unit II, L.P. dated August 7, 2007 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007). |
| 10.32*** | Second Amendment to Agreement of Limited Partnership of EPE Unit II, L.P. dated July 1, 2008 (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008). |
| 10.33*** | Third Amendment to Agreement of Limited Partnership of EPE Unit II, L.P. dated December 2, 2009 (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Enterprise GP Holdings L.P. on December 8, 2009). |
| 10.34*** | Agreement of Limited Partnership of EPE Unit III, L.P. dated May 7, 2007 (incorporated by reference to Exhibit 10.6 to Form 8-K filed by Enterprise GP Holdings L.P. on May 10, 2007). |
| 10.35*** | First Amendment to Agreement of Limited Partnership of EPE Unit III, L.P. dated August 7, 2007 (incorporated by reference to Exhibit 10.5 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007). |
| 10.36*** | Second Amendment to Agreement of Limited Partnership of EPE Unit III, L.P. dated July 1, 2008 (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008). |
| 10.37*** | Third Amendment to Agreement of Limited Partnership of EPE Unit III, L.P. dated December 2, 2009 (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise GP Holdings L.P. on December 8, 2009). |
| 10.38*** | Agreement of Limited Partnership of Enterprise Unit L.P. dated February 20, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 26, 2008). |
| 10.39*** | First Amendment to Agreement of Limited Partnership of Enterprise Unit L.P. dated December 2, 2009 (incorporated by reference to Exhibit 10.4 to Form 8-K filed by Enterprise GP Holdings L.P. on December 8, 2009). |
| 10.40*** | Agreement of Limited Partnership of EPCO Unit L.P. dated November 13, 2008 (incorporated by reference to Exhibit 10.5 to Form 8-K filed November 18, 2008). |
| 10.41*** | First Amendment to Agreement of Limited Partnership of EPCO Unit L.P. dated December 2, 2009 (incorporated by reference to Exhibit 10.5 to Form 8-K filed by Enterprise GP Holdings L.P. on December 8, 2009). |
| 10.42 | Fifth Amended and Restated Administrative Services Agreement, dated as of January 30, 2009, by and among EPCO, Inc., Enterprise GP Holdings L.P., EPE Holdings, LLC, Enterprise Products Partners L.P., Enterprise Products Operating LLC, Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., DEP Holdings, LLC, Duncan Energy Partners L.P., DEP Operating Partnership L.P., TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, LLC, TEPPCO Midstream Companies, LLC, TCTM, L.P. and TEPPCO GP, Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 5, 2009). |
| 10.43 | Amended and Restated Omnibus Agreement dated as of December 8, 2008 among Enterprise Products Operating LLC, DEP Holdings, LLC, Duncan Energy Partners L.P., DEP OLPGP, LLC, DEP Operating Partnership, L.P., Enterprise Lou-Tex Propylene Pipeline L.P., Sabine Propylene Pipeline L.P., Acadian Gas, LLC, Mont Belvieu Caverns, LLC, South Texas NGL Pipelines, LLC, Enterprise Holding III, L.L.C., Enterprise Texas Pipeline, LLC, Enterprise Intrastate, L.P. and Enterprise GC, LP (incorporated by reference to Exhibit 10.6 of Form 8-K filed by Duncan Energy Partners L.P. filed December 8, 2008). |
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| | Contribution, Conveyance and Assumption Agreement dated as of February 5, 2007, by and among Enterprise Products Operating L.P., DEP Holdings, LLC, Duncan Energy Partners L.P., DEP OLPGP, LLC and DEP Operating Partnership, L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Duncan Energy Partners on February 5, 2007). |
| 10.45 | Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P., dated February 5, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K filed by Duncan Energy Partners L.P. on February 5, 2007). |

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| 10.46 | Amendment No. 1 to the Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P. dated December 27, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K/A filed by Duncan Energy Partners L.P. on January 3, 2008). |
| 10.47 | Amendment No. 2 to the Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P. dated November 6, 2008 (incorporated by reference to Exhibit 3.4 to Form 10-Q filed by Duncan Energy Partners L.P. on November 10, 2008). |
| 10.48 | Third Amendment to the Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P. dated December 8, 2008 (incorporated by reference to Exhibit 3.1 to Form 8-K filed by Duncan Energy Partners L.P. on December 8, 2008). |
| 10.49 | Fourth Amendment to the Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P. dated June 15, 2009 (incorporated by reference to Exhibit 3.1 of Form 8-K filed by Duncan Energy Partners L.P. on June 15, 2009). |
| 10.50 | Amended and Restated Credit Agreement dated as of June 29, 2005, among Cameron Highway Oil Pipeline Company, the Lenders party thereto, and SunTrust Bank, as Administrative Agent and Collateral Agent (incorporated by reference to Exhibit 4.1 to Form 8-K filed July 1, 2005). |
| 10.51 | Revolving Credit Agreement, dated as of January 5, 2007, among Duncan Energy Partners L.P., as Borrower, Wachovia Bank, National Association, as Administrative Agent, The Bank of Nova Scotia and Citibank, N.A., as Co-Syndication Agents, JPMorgan Chase Bank, N.A. and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents, and Wachovia Capital Markets, LLC, The Bank of Nova Scotia and Citigroup Global Markets Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.20 to Form S-1/A Registration Statement, Reg. No. 333-138371, filed by Duncan Energy Partners L.P. on January 12, 2007). |
| 10.52 | First Amendment to Revolving Credit Agreement, dated as of June 30, 2007, among Duncan Energy Partners L.P., as Borrower, Wachovia Bank, National Association, as Administrative Agent, The Bank of Nova Scotia and Citibank, N.A., as Co-Syndication Agents, JPMorgan Chase Bank, N.A. and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents, and Wachovia Capital Markets, LLC, The Bank of Nova Scotia and Citigroup Global Markets Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 4.2 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007). |
| 10.53 | Amended and Restated Revolving Credit Agreement dated as of November 19, 2007 among Enterprise Products Operating LLC, the financial institutions party thereto as lenders, Wachovia Bank, National Association, as Administrative Agent, Issuing Bank and Swingline Lender, Citibank, N.A. and JPMorgan Chase Bank, as Co-Syndication Agents, and SunTrust Bank, Mizuho Corporate Bank, Ltd. and The Bank of Nova Scotia, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Form 8-K filed November 20, 2007). |
| 10.54 | Amended and Restated Guaranty Agreement dated as of November 19, 2007 executed by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed November 20, 2007). |
| 10.55 | Term Loan Credit Agreement dated as of November 12, 2008 among Enterprise Products Operating LLC, the financial institutions party thereto as Lenders, Mizuho Corporate Bank, Ltd., as Administrative Agent, a Lender and as Sole Lead Arranger (incorporated by reference to Exhibit 10.1 to Form 8-K filed November 18, 2008). |
| 10.56 | Guaranty Agreement dated as of November 12, 2008 executed by Enterprise Products Partners L.P. in favor of Mizuho Corporate Bank, Ltd., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed November 18, 2008). |
| 10.57 | 364-Day Revolving Credit Agreement dated as of November 17, 2008 among Enterprise Products Operating LLC, the financial institutions party thereto as Lenders, The Royal Bank of Scotland plc, as Administrative Agent, and Barclays Bank plc, The Bank of Nova Scotia, DnB NOR Bank ASA and Wachovia Bank, National Association, as Co-Arrangers (incorporated by reference to Exhibit 10.3 to |

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| | Form 8-K filed November 18, 2008). |
| 10.58 | Guaranty Agreement dated as of November 17, 2008 executed by Enterprise Products Partners L.P. in favor of The Royal Bank of Scotland plc, as Administrative Agent (incorporated by reference to Exhibit 10.4 to Form 8-K filed November 18, 2008). |
| 10.59 | Second Amended and Restated Limited Liability Company Agreement of Mont Belvieu Caverns, LLC, dated November 6, 2008 (incorporated by reference to Exhibit 10.4 to Form 10- |

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| | Q filed by Duncan Energy Partners L.P. on November 10, 2008). |
| 10.60 | Contribution, Conveyance and Assumption Agreement dated as of December 8, 2008 by and among Duncan Energy Partners L.P., DEP OLPGP, LLC, DEP Operating Partnership, L.P., Enterprise GTM Holdings L.P. and Enterprise Holding III, L.L.C. (incorporated by reference to Exhibit 10.2 of Form 8-K filed by Duncan Energy Partners L.P. on December 8, 2008). |
| 10.61 | Purchase and Sale Agreement dated as of December 8, 2008 by and among (a) Enterprise Products Operating LLC and Enterprise GTM Holdings L.P. as the Seller Parties and (b) Duncan Energy Partners L.P., DEP Holdings, LLC, DEP Operating Partnership, L.P. and DEP OLPGP, LLC as the Buyer Parties (incorporated by reference to Exhibit 10.1 of Form 8-K filed by Duncan Energy Partners L.P. on December 8, 2008). |
| 10.62 | Third Amended and Restated Agreement of Limited Partnership of Enterprise GC, L.P. dated December 8, 2008 (incorporated by reference to Exhibit 10.3 of Form 8-K filed by Duncan Energy Partners L.P. on December 8, 2008). |
| 10.63 | Fourth Amended and Restated Agreement of Limited Partnership of Enterprise Intrastate L.P. dated December 8, 2008 (incorporated by reference to Exhibit 10.4 of Form 8-K filed by Duncan Energy Partners L.P. on December 8, 2008). |
| 10.64 | Amended and Restated Company Agreement of Enterprise Texas Pipeline LLC dated December 8, 2008 (incorporated by reference to Exhibit 10.5 of Form 8-K filed by Duncan Energy Partners L.P. on December 8, 2008). |
| 10.65 | Unit Purchase Agreement, dated as of December 8, 2008, by and between Duncan Energy Partners L.P. and Enterprise Products Operating LLC (incorporated by reference to Exhibit 10.9 of Form 8-K filed by Duncan Energy Partners L.P. on December 8, 2008). |
| 10.66 | Term Loan Credit Agreement dated as of April 1, 2009 among Enterprise Products Operating LLC, the financial institutions party thereto as Lenders, Mizuho Corporate Bank, Ltd., as Administrative Agent, a Lender and as Sole Lead Arranger (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 2, 2009). |
| 10.67 | Guaranty Agreement dated as of April 1, 2009 executed by Enterprise Products Partners L.P. in favor of Mizuho Corporate Bank, Ltd., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed April 2, 2009). |
| 10.68 | Support Agreement, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise GP Holdings L.P., DD Securities LLC, DFI GP Holdings, L.P., Duncan Family Interests Inc., Duncan Family 2000 Trust and Dan L. Duncan (incorporated by reference to Exhibit 10.1 to Form 8-K filed June 29, 2009). |
| 10.69 | Memorandum of Understanding, dated June 28, 2009 (incorporated by reference to Exhibit 10.2 to Form 8-K filed June 29, 2009). |
| 10.70 | Stipulation and Agreement of Compromise, Settlement and Release, dated August 5, 2009 (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by TEPPCO Partners, L.P. on August 6, 2009). |
| 10.71 | Common Unit Purchase Agreement, dated September 3, 2009, by and between Enterprise Products Partners L.P. and EPCO Holdings, Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 4, 2009). |
| 12.1 | Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2009, 2008, 2007, 2006 and 2005. |
| 21.1# | List of subsidiaries as of February 1, 2010. |
| 23.1# | Consent of Deloitte & Touche LLP. |
| 31.1# | Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the December 31, 2009 Annual Report on Form 10-K. |
| 31.2# | Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P. for the December 31, 2009 Annual Report on Form 10-K. |

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| 32.1# | Section 1350 certification of Michael A. Creel for the December 31, 2009 Annual Report on Form 10-K. |
| 32.2# | Section 1350 certification of W. Randall Fowler for the December 31, 2009 Annual Report on Form 10-K. |
| 101.CAL# | XBRL Calculation Linkbase Document |
| 101.DEF# | XBRL Definition Linkbase Document |
| 101.INS# | XBRL Instance Document |

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| 101.LAB# | XBRL Labels Linkbase Document |
| 101.PRE# | XBRL Presentation Linkbase Document |
| 101.SCH# | XBRL Schema Document |

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file numbers for Enterprise GP Holdings L.P, Duncan Energy Partners L.P., TEPPCO Partners, L.P. and TE Products Pipeline Company, LLC are 1-32610, 1-33266, 1-10403 and 1-13603, respectively.

*** Identifies management contract and compensatory plan arrangements.

\# Filed with this report.

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## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on March 1, 2010.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)

By: Enterprise Products GP, LLC, as General Partner

| | |
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| By: | /s/ Michael J. Knesek |
| Name: | Michael J. Knesek |
| Title: | Senior Vice President, Controller and Principal Accounting Officer of the General Partner |

Pursuant to the requirements of the Securities Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on March 1, 2010.

| Signature | Title (Position with Enterprise Products GP, LLC) |
|---|---|
| /s/ Dan L. Duncan | |