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

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2013

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 ☑ 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 ☑

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

Large accelerated filer ☑	Accelerated filer o	Non-accelerated filer o	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 ☑

The aggregate market value of the partnership's common units held by non-affiliates at June 28, 2013 (the last business day of the registrant's most recently completed second fiscal quarter) was $36.0 billion based on a closing price on that date of $62.15 per common unit on the New York Stock Exchange Composite ticker tape. There were 935,668,908 common units outstanding at January 31, 2014.

ENTERPRISE PRODUCTS PARTNERS L.P.
TABLE OF CONTENTS

KEY REFERENCES USED IN THIS REPORT

Unless the context requires otherwise, references to “we,” “us,” “our,” “Enterprise” 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, and its consolidated subsidiaries, through which Enterprise Products Partners L.P. conducts its business. Enterprise is managed by its general partner, Enterprise Products Holdings LLC (“Enterprise GP”), which is a wholly owned subsidiary of Dan Duncan LLC, a Texas limited liability company.

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

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

In addition to owning our general partner, affiliates of privately held EPCO owned approximately 36.4% of our limited partner interests at December 31, 2013.

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

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

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This annual report on Form 10-K for the year ended December 31, 2013 (our “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,” “may,” “potential” and similar expressions and statements regarding our plans and objectives for future operations are intended to identify forward-looking statements. Although we and our general partner believe that our expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions as described in more detail under Part I, Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this annual report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

PART I

Item 1 and 2. *Business and Properties*.

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO and are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, petrochemicals and refined products.

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States ("U.S."), Canada and Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals (including liquefied petroleum gas or "LPG"); crude oil gathering, transportation, storage and terminals; offshore production platforms; petrochemical and refined products transportation and services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. Our assets include approximately 51,000 miles of onshore and offshore pipelines; 200 MMBbls of storage capacity for NGLs, petrochemicals, refined products and crude oil; and 14 Bcf of natural gas storage capacity. In addition, our asset portfolio includes 24 natural gas processing plants, 22 NGL and propylene fractionators, six offshore hub platforms located in the Gulf of Mexico, a butane isomerization complex, NGL import and LPG export terminals, and octane enhancement and high-purity isobutylene production facilities.

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

Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers. As of February 1, 2014, there were approximately 6,685 EPCO personnel who spend all or a substantial portion of their time engaged in our business. For additional information regarding the ASA, see "—EPCO ASA" under Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Business Strategy

Our business strategies are to:

§ capitalize on expected increases in the production of natural gas, NGLs and crude oil from development activities in various domestic production basins (e.g., the Rocky Mountains, Mid-Continent, Northeast, U.S. Gulf Coast and deepwater Gulf of Mexico), including associated shale plays such as the Barnett, Eagle Ford, Haynesville, Marcellus, Mancos and Utica Shales;

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

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

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

§ share capital costs and risks through joint ventures or alliances with strategic partners, including those that will provide processing, throughput or feedstock volumes for growth capital projects or purchase such projects' end products.

As noted above, part of our business strategy involves expansion through growth capital projects. We expect that these projects will enhance our existing asset base and provide us with new sources of cash flows in the future. See Part II, Item 7 of this annual report for information regarding our capital spending program.

Duncan Merger – September 2011

Duncan Energy Partners L.P. ("Duncan Energy Partners") was formed by Enterprise Products Partners in September 2006 and completed its initial public offering in February 2007 (NYSE: DEP). Duncan Energy Partners was under common control with Enterprise by affiliates of EPCO and its business purpose was to acquire, own and operate midstream energy assets.

In April 2011, we, our general partner, EPD MergerCo LLC ("Duncan MergerCo," our wholly owned subsidiary), Duncan Energy Partners and DEP Holdings, LLC ("DEP GP," the general partner of Duncan Energy Partners) entered into a merger agreement (the "Duncan Merger Agreement"). In September 2011, the Duncan Merger Agreement was approved by the unitholders of Duncan Energy Partners and the merger of Duncan MergerCo with and into Duncan Energy Partners and related transactions were completed, with Duncan Energy Partners surviving such merger as our wholly owned subsidiary (collectively, we refer to these transactions as the "Duncan Merger"). We believe this merger transaction streamlined and simplified our organizational structure to be more transparent to investors, removed potential conflicts of interest due to common control considerations and reduced public company overhead costs.

Each issued and outstanding common unit of Duncan Energy Partners was cancelled and converted into the right to receive our limited partner common units based on an exchange ratio of 1.01 Enterprise common units for each Duncan Energy Partners common unit. We issued 24,277,310 of our common units (net of fractional common units cashed out) to the former public unitholders of Duncan Energy Partners as consideration in the Duncan Merger. We did not issue any common units as merger consideration to our subsidiaries that owned limited partner interests in Duncan Energy Partners.

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

Major Customer Information

Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base. Our largest non-affiliated customer for 2013 and 2012 was BP p.l.c. and its affiliates, which accounted for 9.0% of our consolidated revenues in 2013 and 9.5% of our consolidated revenues in 2012. Shell Oil Company and its affiliates was our largest non-affiliated customer in 2011, accounting for 10.6% of our consolidated revenues for that year. For information regarding our revenue recognition policies, see Note 4 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

General Outlook for 2014

For information regarding our commercial and liquidity outlook for the year ending December 31, 2014, see "General Outlook for 2014" included under Part II, Item 7 of this annual report.

Business Segments

The following sections provide an overview of our business segments, including information regarding principal products produced and/or services rendered, properties owned, seasonality and competition. 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 types of services rendered (or technologies employed) and products produced and/or sold.

Each of our business segments benefits from the supporting role of our related marketing activities. The main purpose of our marketing activities is to support the utilization of assets across our midstream energy asset network by increasing the volumes handled by such assets, which results in additional fee-based earnings for each business segment. In performing these support roles, our marketing activities also seek to participate in supply and demand opportunities as another source of gross operating margin for the partnership. The financial results of our marketing efforts fluctuate period-to-period due to changes in volumes handled and overall market conditions, which may be influenced by current and forward market prices for the products bought and sold.

For detailed financial information regarding our business segments (including our consolidated revenues by segment), see Note 13 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report. Such financial information is incorporated by reference into this Item 1 and 2 discussion. In addition, we utilize derivative instruments in connection with certain of our operations. For information regarding our use of derivative instruments, see Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Our results of operations and financial condition are subject to certain significant risks. For information regarding these risks, see Part I, Item 1A of this annual report. In addition, our business activities are subject to various federal, state and local laws and regulations governing a wide variety of topics, including commercial, operational, environmental, safety and other matters. For a discussion of the principal effects of such laws and regulations on our business activities, see "Regulatory Matters" within this Part I, Item 1 and 2 discussion.

For management's discussion and analysis of our results of operations, liquidity and capital resources and capital spending program, see Part II, Item 7 of this annual report.

NGL Pipelines & Services

Our NGL Pipelines & Services business segment includes our natural gas processing plants and related NGL marketing activities; approximately 19,400 miles of NGL pipelines; NGL and related product storage facilities; and 15 NGL fractionators. This segment also includes our NGL import and LPG export terminal operations.

Purity NGL products (ethane, propane, normal butane, isobutane and natural gasoline) are used as feedstocks by the petrochemical industry, as feedstocks by refineries in the production of motor gasoline and as fuel by industrial and residential consumers. Ethane is primarily used in the petrochemical industry as a feedstock in the production of ethylene, 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. LPG, which is a mixture of propane and/or butane, is used as a feedstock in ethylene plant operations and for power generation and heating purposes.

Natural gas processing plants and related NGL marketing activities. At the core of our natural gas processing business are 24 processing plants located across Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming.

In its raw form, natural gas produced at the wellhead (especially in association with crude oil) contains varying amounts of mixed NGLs. Natural gas streams containing NGLs are usually not acceptable for transportation in natural gas pipelines or for commercial use as a fuel and must be sent to natural gas processing plants to remove the NGLs. Once the natural gas is processed and NGLs and impurities are removed, the natural gas will meet pipeline and commercial quality specifications. On an energy equivalent basis, most NGLs generally have greater economic value as feedstock for petrochemical and motor gasoline production than as components of a natural gas stream.

Once the mixed NGLs are extracted by a natural gas processing plant, they are typically transported to a centralized fractionation facility for separation into purity NGL products. The NGLs we obtain through our processing arrangements (referred to as our "equity NGL production" volumes) or purchase directly from third parties are used in our NGL marketing activities to meet contractual requirements or sold in spot and forward markets. Also, we purchase raw natural gas streams from producers in connection with our natural gas processing activities. Once processed, this natural gas is available for sale through our natural gas marketing activities.

In our natural gas processing business, we utilize contracts that are either fee-based, commodity-based or a combination of the two. When a cash fee for natural gas processing services is stipulated by a contract, we record revenue when a producer's natural gas has been processed and redelivered. In recent years, our portfolio of natural gas processing contracts has become increasingly weighted towards those with fee-based terms as producers seek to maximize the value of their production by retaining all or a portion of the NGLs extracted from their natural gas stream. We estimate that the terms of approximately 43% of our current portfolio of natural gas processing contracts are entirely fee-based, with an additional 19% of this portfolio including a combination of fee-based and commodity-based terms. The terms of the remaining 38% of our portfolio of natural gas processing contracts are entirely commodity-based.

Our commodity-based contracts include keepwhole and margin-band contracts, percent-of-liquids contracts, percent-of-proceeds contracts and contracts featuring a combination of commodity and fee-based terms. Under keepwhole and margin-band contracts, we take ownership of mixed NGLs extracted from the producer's natural gas stream while replacing the equivalent quantity of energy on a natural gas basis to producers. We recognize revenue when the extracted NGLs are delivered and sold to customers under NGL marketing sales contracts. Under percent-of-liquids contracts, we take ownership of a portion of the mixed NGLs extracted from the producer's natural gas stream (in lieu of a cash processing fee) and recognize revenue when the extracted NGLs are delivered and sold to customers under NGL marketing sales contracts. Under percent-of-proceeds contracts, we share in the proceeds generated from the sale of mixed NGLs we extract on the producer's behalf (in lieu of a cash processing fee). In certain cases, we also utilize contracts that include a combination of commodity-based terms (such as those described above) and fee-based terms.

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.

The value of natural gas lost as a result of NGL extraction (i.e., shrinkage) and consumed as plant fuel is referred to as plant thermal reduction, which is a significant cost of natural gas processing. To the extent that we are obligated under keepwhole and margin-band contracts to compensate the producer for shrinkage and plant fuel, we are exposed to fluctuations in the price of natural gas; however, margin-band contracts typically contain terms that limit our exposure to such risks. Under the terms of our other processing arrangements (i.e., those agreements with fee-based, percent-of-liquids and percent-of-proceeds terms), the producer typically bears the cost of plant thermal reduction.

If the operating and extraction costs of natural gas processing plants are higher than the incremental value of the NGL products that would be extracted, then recovery levels of certain NGL products, principally ethane, may be purposefully reduced or eliminated. This scenario is typically referred to as "ethane rejection" and leads to a reduction in NGL volumes available for subsequent transportation, fractionation, storage and marketing. In general, contracts with keepwhole or percent-of-liquids terms provide 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 equity NGL production we would obtain as consideration for processing services.

Our NGL marketing activities generate revenues from the sale and delivery of NGLs we take title to through our natural gas processing activities (i.e., our equity NGL production) and open market and contract purchases. The results of operations from our NGL marketing activities are primarily dependent upon the difference, or spread, between NGL sales prices and the associated purchase and other costs, including those costs attributable to the use of our other assets. In general, sales prices referenced in the underlying contracts are market-based and may include pricing differentials for factors such as delivery location or NGL product quality. 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 price risks through the use of commodity derivative instruments.

The following table presents selected information regarding our natural gas processing facilities at February 1, 2014:

Description of Asset	Location(s)	Our Ownership Interest		Net Gas Processing Capacity (Bcf/d) (1)	Total Gas Processing Capacity (Bcf/d)
Natural gas processing facilities:					
Meeker	Colorado	100.0%		1.80	1.80
Pioneer (two facilities)	Wyoming	100.0%		1.35	1.35
Yoakum	Texas	100.0%		1.05	1.05
Toca	Louisiana	68.0%	(2)	0.66	1.10
Chaco	New Mexico	100.0%		0.60	0.60
North Terrebonne	Louisiana	59.5%	(2)	0.57	0.95
Neptune	Louisiana	66.0%	(2)	0.43	0.65
Pascagoula	Mississippi	40.0%	(2)	0.40	1.50
Thompsonville	Texas	100.0%		0.33	0.33
Shoup	Texas	100.0%		0.29	0.29
Sea Robin	Louisiana	40.0%	(2)	0.28	0.65
Gilmore	Texas	100.0%		0.25	0.25
Armstrong	Texas	100.0%		0.25	0.25
San Martin	Texas	100.0%		0.20	0.20
Indian Basin	New Mexico	42.4%	(2)	0.18	0.18
Delmita	Texas	100.0%		0.15	0.15
Carlsbad	New Mexico	100.0%		0.13	0.13
Sonora	Texas	100.0%		0.12	0.12
Shilling	Texas	100.0%		0.11	0.11
Venice	Louisiana	13.1%	(3)	0.10	0.75
Indian Springs	Texas	75.0%	(2)	0.09	0.12
Burns Point	Louisiana	50.0%	(2)	0.08	0.16
Chaparral	New Mexico	100.0%		0.04	0.04
Total processing capacities				9.46	12.73

(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 ownership interest in the facility.
(2) We proportionately consolidate our undivided interest in these operating assets.
(3) Our ownership in the Venice plant is held indirectly through our equity method investment in Venice Energy Services Company, L.L.C. (“VESCO”).

Our natural gas processing facilities can be characterized as two distinct types: (i) straddle plants situated on mainline natural gas pipelines owned either by us or by third parties or (ii) field plants that process natural gas from gathering pipelines. We operate all of our natural gas processing facilities except for the Pascagoula, Venice and Indian Basin plants. On a weighted-average basis, utilization rates for our natural gas processing plants were 54.1%, 55.9% and 56.1% during the years ended December 31, 2013, 2012 and 2011, respectively.

In March 2013, we completed the third and final phase (or "train") at our Yoakum natural gas processing facility. In the aggregate, the three processing trains at Yoakum can process up to a combined 1.05 Bcf/d of natural gas and extract approximately 144 MBPD of mixed NGLs. The Yoakum facility processes natural gas produced primarily from the Eagle Ford Shale and is linked by pipeline to our Wilson natural gas storage facility and various downstream markets. Mixed NGLs extracted at the Yoakum plant are transported to our NGL fractionation and storage complex at Mont Belvieu, Texas.

Our NGL marketing activities utilize a fleet of approximately 670 railcars, the majority of which are leased from third parties. These railcars are used to deliver feedstocks to our facilities and to distribute NGLs throughout the U.S. and parts of Canada. We have rail loading and unloading capabilities at certain of our terminal facilities in 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.

NGL pipelines. Our NGL pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities, refineries and import terminals to fractionation plants and storage facilities; gather and distribute purity NGL products to and from fractionation plants, storage and terminal facilities, petrochemical plants, export facilities and refineries; and deliver propane to destinations along our various pipeline systems.

The results of operations from our NGL pipelines are primarily dependent upon the volume of NGLs transported and the associated fees we charge for such services. Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies, including the Federal Energy Regulatory Commission ("FERC"), or contractual arrangements. Typically, pipeline transportation revenue is recognized when volumes are delivered to customers. However, under certain NGL pipeline transportation agreements (e.g., those associated with committed shippers on our Texas Express Pipeline, Front Range Pipeline and ATEX Express pipeline), customers are required to ship a minimum volume over an agreed-upon period. These arrangements typically entail the shipper paying a transportation fee based on a minimum volume commitment, with a provision that allows the shipper to make-up any volume shortfalls over the agreed-upon period (referred to as shipper "make-up rights"). Revenue pursuant to such agreements, including that associated with make-up rights, is recognized at the earlier of when the volume is shipped, when the shipper's ability to meet the minimum volume commitment has expired, or when the pipeline is otherwise released from its performance obligation.

Excluding inventories owned 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.

The following table presents selected information regarding our NGL pipelines at February 1, 2014:

Description of Asset	Location(s)	Our Ownership Interest		Length (Miles)
NGL pipelines:				
Mid-America Pipeline System (1)	Midwest and Western U.S.	100.0%		8,109
South Texas NGL Pipeline System	Texas	100.0%		1,768
Dixie Pipeline (1)	South and Southeastern U.S.	100.0%		1,306
Appalachia-to-Texas Express (1)	Texas to Midwest and Northeast U.S.	100.0%		1,265
Seminole Pipeline (1)	Texas	100.0%		1,250
Chaparral NGL System (1)	Texas, New Mexico	100.0%		1,008
Louisiana Pipeline System	Louisiana	100.0%		951
Texas Express Pipeline (1)	Texas	35.0%	(2)	593
Skelly-Belvieu Pipeline (1)	Texas	50.0%	(3)	572
Front Range Pipeline (1)	Colorado, Oklahoma, Texas	33.3%	(4)	435
Promix NGL Gathering System	Louisiana	50.0%	(5)	351
Houston Ship Channel	Texas	100.0%		300
Rio Grande Pipeline (1)	Texas	70.0%	(6)	249
Panola Pipeline	Texas	100.0%		223
Lou-Tex NGL Pipeline (1)	Texas, Louisiana	100.0%		204
Tri-States NGL Pipeline (1)	Alabama, Mississippi, Louisiana	83.3%	(7)	167
Chunchula Pipeline (1)	Alabama, Mississippi	100.0%		144
Texas Express Gathering System	Texas, Oklahoma	45.0%	(8)	116
Others (six systems) (9)	Various	Various	(10)	422
Total miles				19,433

(1) Interstate and/or intrastate transportation services provided by these liquids pipelines are regulated by governmental agencies.
(2) Our ownership interest in the Texas Express Pipeline is held indirectly through our equity method investment in Texas Express Pipeline LLC.
(3) Our ownership interest in the Skelly-Belvieu Pipeline is held indirectly through our equity method investment in Skelly-Belvieu Pipeline Company, L.L.C.
(4) Our ownership interest in the Front Range Pipeline is held indirectly through our equity method investment in Front Range Pipeline LLC.
(5) Our ownership interest in the Promix NGL Gathering System is held indirectly through our equity method investment in K/D/S Promix, L.L.C. ("Promix").
(6) We own a 70% consolidated interest in the Rio Grande Pipeline through our majority owned subsidiary, Rio Grande Pipeline Company.
(7) We own an 83.3% consolidated interest in the Tri-States NGL Pipeline through our majority owned subsidiary, Tri-States NGL Pipeline, L.L.C.
(8) Our ownership interest in the Texas Express Gathering System is held indirectly through our equity method investment in Texas Express Gathering LLC ("Texas Express Gathering").
(9) Includes our Belle Rose and Wilprise pipelines located in the coastal regions of Louisiana and Mississippi; two Port Arthur pipelines located in southeast Texas; a pipeline in Colorado associated with our Meeker facility; and the South Dean Pipeline in Texas.
(10) We own a 74.7% consolidated interest in the 30-mile Wilprise pipeline through our majority owned subsidiary, Wilprise Pipeline Company, LLC. We proportionately consolidate our 50% undivided interest in a 45-mile segment of the Port Arthur pipelines. The remainder of these NGL pipelines are wholly owned.

As noted previously, certain of our NGL pipelines are subject to regulation. See "Regulatory Matters" within this Part I, Item 1 and 2 discussion for additional information regarding governmental oversight of liquids pipelines, including tariffs charged for transportation services.

The maximum number of barrels per day that our NGL pipelines can transport depends on the operating balance achieved at a given point in time between various segments of each system (e.g., demand levels at each delivery point and the mix of products being transported). As a result, we measure the utilization rates of our petrochemical pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 2,540 MBPD, 2,327 MBPD and 2,180 MBPD during the years ended December 31, 2013, 2012 and 2011, respectively.

The following information describes each of our principal NGL pipelines. We operate our NGL pipelines with the exception of the Texas Express Gathering System and Tri-States NGL Pipeline.

§ The *Mid-America Pipeline System* is an NGL pipeline system consisting of four primary segments: the 3,183-mile Rocky Mountain pipeline, the 2,194-mile Conway North pipeline, the 574-mile Ethane-Propane Mix pipeline and the 2,158-mile Conway South pipeline. The Mid-America Pipeline System is present in 13 states: Colorado, Illinois, Iowa, Kansas, Minnesota, Missouri, Nebraska, New Mexico, Oklahoma, Texas, Utah, Wisconsin and Wyoming. The Rocky Mountain pipeline transports mixed NGLs from the Rocky Mountain Overthrust and San Juan Basin areas to the Hobbs NGL 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. NGL hubs such as those at Hobbs and Conway provide buyers and sellers a centralized location for the storage and pricing of products, while also providing connections to intrastate and/or interstate pipelines. In addition, the Conway North segment has access to NGL supplies from Canada's Western Sedimentary Basin through third party connections. The Ethane-Propane Mix segment transports ethane/propane mix primarily to petrochemical plants in Iowa and Illinois from the NGL hub at Conway. The Conway South pipeline connects the Conway hub with Kansas refineries and provides bi-directional transportation of NGLs between the Conway and Hobbs hubs. At the Hobbs NGL hub, the Mid-America Pipeline System interconnects with our Seminole Pipeline and Hobbs NGL fractionation and storage facility. The Mid-America Pipeline System is also connected to 19 non-regulated NGL terminals that we own and operate.

Volumes transported on the Mid-America Pipeline System originate from natural gas processing plants in the Rocky Mountains and Mid-Continent regions, as well as NGL fractionation and storage facilities in Kansas and Texas.

In January 2014, we completed an expansion project involving the Rocky Mountain pipeline of our Mid-America Pipeline System. This expansion project involved looping 265 miles of the Rocky Mountain pipeline, as well as related pump station modifications, which increased transportation capacity on the pipeline from approximately 275 MBPD to 350 MBPD (after taking into account shipper commitments to the expansion project). This expansion project was built to accommodate growing natural gas and NGL production from major supply basins in Colorado, Utah and Wyoming.

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

We placed 188 miles of pipelines belonging to this system into service in phases between May 2012 and March 2013. This included a 168-mile segment that transports mixed NGLs from our Yoakum natural gas processing plant to our Mont Belvieu NGL fractionation and storage complex. In addition, we placed into service a 173-mile NGL pipeline that extends from our Yoakum facility to a third party natural gas processing plant located in LaSalle County, Texas, and provides NGL pipeline takeaway capacity for additional third party gas plants. This pipeline extension commenced operations in June 2013.

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

§ *Appalachia-to-Texas Express* pipeline ("ATEX Express") transports ethane in southbound service from NGL fractionation plants located in Ohio, Pennsylvania and West Virginia to our Mont Belvieu storage complex. The ethane extracted by these fractionation facilities originates from the Marcellus and Utica Shale production areas. ATEX Express began commercial operations in January 2014 and operates in nine states: Arkansas, Illinois, Indiana, Louisiana, Missouri, Ohio, Pennsylvania, Texas and West Virginia. In addition to newly constructed pipeline segments, significant portions of ATEX Express consist of pipeline segments that were formerly used in refined products transportation service by our TE Products Pipeline. Initial throughput capacity for the ATEX Express pipeline is 125 MBPD, which could be expanded to approximately 265 MBPD with certain system modifications.

ATEX Express terminates at our Mont Belvieu storage complex, which includes approximately 110 MMBbls of NGL and petroleum liquid storage capacity and an extensive pipeline distribution system. With the addition of our Aegis Ethane Pipeline (currently under construction), we will link Marcellus and Utica Shale-produced ethane to existing ethylene production facilities along the U.S. Gulf Coast and provide supply security to support construction of new third-party ethylene plants currently planned at Texas and Louisiana petrochemical facilities. Also, since our distribution system supports our LPG export terminal on the Houston Ship Channel, ethane volumes delivered to Mont Belvieu via ATEX Express may enhance the prospects for U.S.-produced ethane being exported to international markets.

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

In March 2013, we sold the former Stratton Ridge-to-Mont Belvieu segment of the Seminole Pipeline, along with a related storage cavern, to a third party for cash proceeds of $86.9 million. As a result, net income for the year ended December 31, 2013 includes a $52.5 million gain attributable to the sale of these assets. The Seminole Pipeline remains connected to our Mont Belvieu complex through a newly constructed pipeline segment that we own.

§ The *Chaparral NGL System* transports mixed NGLs from natural gas processing plants in West Texas and New Mexico to Mont Belvieu, Texas. This system consists of the 828-mile Chaparral pipeline and the 180-mile Quanah pipeline. Interstate and intrastate transportation services provided by the Chaparral pipeline are regulated; however, transportation services provided by the Quanah pipeline are not.

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

The *Texas Express Pipeline* extends from Skellytown, Texas to our NGL fractionation and storage complex at Mont Belvieu, Texas. This pipeline commenced operations in November 2013. Mixed NGL volumes from the Rocky Mountains, Permian Basin and Mid-Continent regions are delivered to the Texas Express Pipeline via an interconnect with our Mid-America Pipeline System near Skellytown. The Texas Express Pipeline also transports mixed NGL volumes from two gathering systems owned by Texas Express Gathering to Mont Belvieu. In addition, mixed NGL volumes from the Denver-Julesburg supply basin are transported to the Texas Express Pipeline using the Front Range Pipeline, which commenced operations in February 2014. Initial throughput capacity for the Texas Express Pipeline is 280 MBPD, which could be expanded to approximately 400 MBPD with certain system modifications.

The Texas Express Pipeline is owned by Texas Express Pipeline LLC, which is a joint venture among us and affiliates of Enbridge, Inc. ("Enbridge"), Anadarko Petroleum Corporation ("Anadarko") and DCP Midstream Partners LP ("DCP"). We operate the Texas Express Pipeline and have a 35% ownership interest in Texas Express Pipeline LLC.

- The *Skelly-Belvieu Pipeline* transports mixed NGLs from Skellytown, Texas to Mont Belvieu, Texas. The Skelly-Belvieu Pipeline receives NGLs through a pipeline interconnect with our Mid-America Pipeline System in Skellytown, Texas.

- The *Front Range Pipeline*, which commenced operations in February 2014, transports mixed NGLs from natural gas processing plants located in the Denver-Julesburg Basin in Colorado to an interconnect with our Texas Express Pipeline and Mid-America Pipeline System at Skellytown, Texas. Initial throughput capacity for the Front Range Pipeline is 150 MBPD, which could be expanded to approximately 230 MBPD with certain system modifications.

  The Front Range Pipeline is owned by Front Range Pipeline LLC, which is a joint venture among us and affiliates of DCP and Anadarko. We operate the Front Range Pipeline and have a one-third ownership interest in the joint venture.

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

- The *Houston Ship Channel* pipeline system connects our Mont Belvieu complex to 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* transports mixed NGLs from near Odessa, Texas to a pipeline interconnect at the Mexican border south of El Paso, Texas.

- The *Panola Pipeline* transports mixed NGLs from northeast Texas near Carthage in Panola County to Mont Belvieu, Texas. The Panola Pipeline supports the Haynesville and Cotton Valley oil and gas production areas.

- The *Lou-Tex NGL Pipeline* system transports mixed NGLs, purity NGL products and refinery grade propylene between the Louisiana and Texas markets.

- The *Tri-States NGL Pipeline* transports mixed NGLs from Mobile Bay, Alabama to points near Kenner, Louisiana and is operated by BP.

- The *Chunchula Pipeline* transports propane and butane from the Alabama-Florida border to our storage facility at Petal, Mississippi.

- The *Texas Express Gathering System* is comprised of two NGL gathering systems that deliver volumes to the Texas Express Pipeline. These gathering systems commenced operations in November 2013. The Elk City gathering system currently comprises 55 miles of pipeline and gathers mixed NGLs from natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and western Oklahoma. The North Texas gathering system currently comprises 61 miles of pipeline and gathers mixed NGLs from natural gas processing plants in the Barnett Shale production area in North Texas. Enbridge serves as operator of these two NGL gathering systems.

  The Texas Express Gathering Systems are owned by Texas Express Gathering LLC, which is a joint venture among us and affiliates of Enbridge and Anadarko. We have a 45% ownership interest in Texas Express Gathering LLC.

In March 2013, we announced the receipt of transportation commitments to support development of our 270-mile *Aegis Ethane Pipeline*, which will deliver ethane to petrochemical plants in the U.S. Gulf Coast region. The Aegis Ethane Pipeline will originate at our Mont Belvieu, Texas storage complex and have the capacity to transport up to 425 MBPD of purity ethane volumes to various petrochemical customers along the Gulf Coast of Texas and Louisiana. The Aegis Ethane Pipeline is expected to commence operations in stages, with initial sections starting service in the third quarter of 2014 and the remaining sections at different times through the second quarter of 2015.

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

The following table presents selected information regarding our NGL and related product storage assets at February 1, 2014:

Storage Capacity by State	Net Usable Storage Capacity (MMBbls)
Texas (1)	126.4
Louisiana	12.9
Kansas	8.6
Mississippi	5.1
Others (2)	7.4
Total net usable storage capacity (3)	160.4

(1) The amount shown for Texas includes 35 underground NGL, petrochemical and refined products storage caverns with an aggregate working capacity of approximately 110 MMBbls located in Mont Belvieu, Texas.

(2) Includes storage capacity at facilities in Alabama, Arizona, California, Georgia, Illinois, Indiana, Iowa, Minnesota, Missouri, Nebraska, Nevada, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina and Wisconsin.

(3) Our aggregate net usable storage capacity includes 17.8 MMBbls held under long-term operating leases at facilities located in Indiana, Kansas, Louisiana and Texas. Approximately 1.5 MMBbls of our net usable storage capacity in Louisiana is held indirectly through our equity method investment in Promix. The remainder of our NGL underground storage caverns and above ground storage tanks are wholly owned.

Our NGL and related product storage facilities are important components of our midstream energy infrastructure. We operate these facilities, with the exception of certain Louisiana storage locations, the leased Markham facility in Texas and another leased facility in Kansas. Our largest underground storage facility is located in Mont Belvieu, Texas. This facility consists of 35 underground storage caverns used to store and redeliver mixed NGLs and NGL purity, petrochemical and related products for industrial customers located along the upper Texas Gulf Coast. This facility has an aggregate usable storage capacity of approximately 110 MMBbls, a brine system with approximately 20 MMBbls of above-ground brine storage pit capacity and two brine production wells.

LPG export services and related operations. We provide customers with LPG export services at our marine terminal located on the Houston Ship Channel. This terminal has the capability to load cargoes of fully refrigerated, low-ethane propane and/or butane onto multiple tanker vessels simultaneously. In March 2013, we completed an expansion project at this terminal that increased its loading capability from 4.0 MMBbls per month to 7.5 MMBbls per month. Our LPG export services continue to benefit from increased NGL supplies produced from domestic shale plays such as the Eagle Ford Shale and strong international demand for propane as a feedstock in ethylene plant operations and for power generation and heating purposes. Our average LPG loading volumes at this terminal were 231 MBPD, 131 MBPD and 93 MBPD during the years ended December 31, 2013, 2012 and 2011, respectively.

In September 2013, we announced an expansion project at this LPG export terminal that is expected to increase its ability to load cargoes from 7.5 MMBbls per month to approximately 9.0 MMBbls per month. This expansion project is expected to be completed in the first quarter of 2015.

In January 2014, we announced a further expansion of this LPG export terminal that is expected to increase its ability to load cargoes from approximately 9.0 MMBbls per month to in excess of 16.0 MMBbls per month. Once this expansion project is completed, we expect our maximum loading capacity at this export terminal will be approximately 27,000 barrels per hour. This expansion project is supported by a 50-year service agreement with Oiltanking Partners, L.P. ("Oiltanking"), which has agreed to provide additional dock space and related services to us at the terminal site. The expanded LPG export terminal is expected to be in service by the end of 2015 and is supported by long-term LPG export agreements.

We also own an NGL import facility located at the same terminal as our Houston Ship Channel LPG export terminal. This import facility can offload NGLs from tanker vessels at rates up to 14,000 barrels per hour depending on the product. Our NGL import volumes were minimal during each of the years ended December 31, 2013, 2012 and 2011. We lease the site that our Houston Ship Channel NGL import and LPG export facility is located on from Oiltanking.

The results of operations from our export and import services are primarily dependent upon the volume handled and the associated fees we charge for such services. Revenue from NGL import and LPG export terminaling activities is recorded in the period services are provided. Customers are typically billed a fee per unit of volume loaded or unloaded. With respect to our export terminal operations, revenue may also include deficiency fees charged to customers who reserve capacity at our export facilities and later fail to use such capacity. Deficiency fee revenue is recognized when the customer fails to utilize the specified export capacity as required by contract.

NGL fractionation. We own or have interests in 15 NGL fractionators located in Texas and Louisiana. NGL fractionators separate mixed NGL streams into purity NGL products. The primary sources of mixed NGLs fractionated in the U.S. are domestic natural gas processing plants, crude oil refineries and imports of butane and propane mixtures. Mixed NGLs sourced from domestic natural gas processing plants and crude oil refineries are typically transported by NGL pipelines and, to a lesser extent, by railcar and truck to NGL fractionation facilities.

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 natural gas processing plants located along the Gulf Coast and in the Rocky Mountains and Mid-Continent regions, will be available for fractionation in commercially viable quantities for the foreseeable future. Significant volumes of mixed NGLs are contractually committed to be processed at our NGL fractionators by joint owners and third party customers.

Our NGL fractionation facilities process mixed NGL streams for third party customers and also 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 (e.g., natural gas fuel costs). At our Norco facility in Louisiana, we perform fractionation services for certain customers under percent-of-liquids contracts.

The results of operations of our NGL fractionation business are generally dependent upon the volume of mixed NGLs fractionated and either the level of fractionation fees charged (under fee-based contracts) or the value of NGLs received (under percent-of-liquids arrangements). Our fee-based fractionation customers retain title to the NGLs that we process for them. To the extent we fractionate volumes for customers under percent-of-liquids contracts, we are exposed to fluctuations in NGL prices (i.e., commodity price risk). We attempt to mitigate these risks through the use of commodity derivative instruments such as forward sales contracts.

The following table presents selected information regarding our NGL fractionation facilities at February 1, 2014:

Description of Asset	Location	Our Ownership Interest		Net Plant Capacity (MBPD) (1)	Total Plant Capacity (MBPD)
NGL fractionation facilities:					
Mont Belvieu (2)	Texas	Various	(3)	572	670
Shoup and Armstrong	Texas	100.0%		98	98
Hobbs	Texas	100.0%		75	75
Norco	Louisiana	100.0%		75	75
Promix	Louisiana	50.0%	(4)	73	145
BRF	Louisiana	32.2%	(5)	19	60
Tebone	Louisiana	56.2%	(6)	17	30
Total plant fractionation capacities				929	1,153

(1) The approximate net plant capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as the level of volumes an owner processes at the facility and its ownership interest in the facility.
(2) There are eight NGL fractionators located at our Mont Belvieu, Texas facility. The seventh and eighth NGL fractionators at this facility commenced operations in September 2013 and November 2013, respectively.
(3) Of the eight NGL fractionators at our Mont Belvieu complex, we proportionately consolidate our 75% undivided interest in four of the units and wholly own two of the units. We own a 75% consolidated interest in NGL fractionators seven and eight through our majority owned subsidiary, Enterprise EF78 LLC.
(4) Our ownership interest in the Promix fractionator is held indirectly through our equity method investment in Promix.
(5) Our ownership interest in the BRF fractionator is held indirectly through our equity method investment in Baton Rouge Fractionators LLC ("BRF").
(6) We proportionately consolidate our undivided 56.2% interest in the Tebone fractionator.

On a weighted-average basis, overall utilization rates for our NGL fractionators were 88.5%, 91.9% and 90.2% during the years ended December 31, 2013, 2012 and 2011, respectively. We operate all of our NGL fractionators.

The following information describes each of our principal NGL fractionators:

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

We placed the seventh and eighth NGL fractionators at our Mont Belvieu complex into operation in September 2013 and November 2013, respectively. These two new fractionators (each with 85 MBPD of fractionation capacity) were built to handle increasing NGL production from domestic shale plays, including the Eagle Ford Shale in South Texas and other supply basins in the Rocky Mountains and Mid-Continent regions. Our seventh and eighth NGL fractionators are owned by a joint venture, formed in June 2013, between us and Western Gas Partners, LP ("Western Gas"), which is an affiliate of Anadarko. We own 75% of the joint venture's membership interests, with Western Gas owning a 25% noncontrolling interest in the joint venture.

§ 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 fractionator is located in Gaines County, Texas, where it serves demand for NGLs in West Texas, New Mexico, California and northern Mexico. The Hobbs fractionator receives mixed NGLs from several major supply basins, including Mid-Continent, Permian Basin, San Juan Basin and the Rocky Mountains. The facility is located at the interconnect of our Mid-America Pipeline System and Seminole Pipeline, thus providing us the operating flexibility to supply both 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 fractionator receives mixed NGLs via pipeline from refineries and natural gas processing plants located in southern Louisiana and along the Mississippi and Alabama Gulf Coast, including our Pascagoula, Venice and Toca facilities.

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

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

Seasonality. Our natural gas processing and NGL fractionation operations typically exhibit little seasonal variation. Our NGL marketing activities rely on inventories of purity NGL products. Propane and normal butane inventories are typically at higher levels from March through November since these products are normally in higher demand and at higher price levels during the winter months. Ethane, isobutane and natural gasoline inventories are generally stable and less cyclical throughout the year.

NGL pipeline transportation volumes are generally higher from October through March due to higher demand for propane (for residential heating purposes) 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.

Seasonality has little impact on our LPG export terminal operations; however, historical NGL import volumes have been higher during the spring and summer months. Lastly, our facilities located along the Gulf Coast of the U.S. may be affected by weather events such as hurricanes and tropical storms, which generally arise during the summer and fall months.

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

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

We compete with a number of NGL fractionators in Texas, Louisiana, New Mexico and Kansas. Competition for such services is primarily based on the fractionation fee charged. However, the ability of an NGL fractionator to receive a customer's mixed NGLs and store and distribute the resulting purity NGL products is also an important competitive factor and is a function of having the necessary pipeline and storage infrastructure.

Onshore Natural Gas Pipelines & Services

Our Onshore Natural Gas Pipelines & Services business segment includes approximately 19,600 miles of onshore natural gas pipeline systems that provide for the gathering and transportation of natural gas in Colorado, Louisiana, New Mexico, Texas and Wyoming. We lease underground salt dome natural gas storage facilities located in Texas and Louisiana and own an underground salt dome storage cavern in Texas, all of which are important to our natural gas pipeline operations. This segment also includes our related natural gas marketing activities.

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

The results of operations from our onshore natural gas pipelines and related storage assets are primarily dependent upon the volume of natural gas transported or stored, the level of firm capacity reservations made by shippers, and the associated fees we charge for such activities. Transportation fees charged to shippers (typically per MMBtu of natural gas) are based on either tariffs regulated by governmental agencies, including the FERC, or contractual arrangements. Certain of our onshore natural gas pipelines offer firm capacity reservation services whereby the shipper pays a contractual fee based on the level of throughput capacity reserved (whether or not the shipper actually utilizes such capacity). Under our natural gas storage revenue contracts, there are typically two components: (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.

The following table presents selected information regarding our onshore natural gas pipelines and related storage assets at February 1, 2014:

Description of Asset	Location(s)	Our Ownership Interest		Length (Miles)	Approximate Net Capacity Pipelines (MMcf/d)	Approximate Net Capacity Usable Storage (Bcf)
Onshore natural gas pipelines and related storage assets:						
Texas Intrastate System (1)	Texas	Various	(2)	8,324	6,640	12.9
Acadian Gas System (1)	Louisiana	100.0%	(3)	1,301	3,100	1.3
Jonah Gathering System	Wyoming	100.0%		773	2,360	--
San Juan Gathering System	New Mexico, Colorado	100.0%		6,177	1,750	--
Piceance Basin Gathering System	Colorado	100.0%		184	1,600	--
White River Hub (4)	Colorado	50.0%	(5)	10	1,500	--
Haynesville Gathering System	Louisiana, Texas	100.0%		320	1,300	--
Fairplay Gathering System	Texas	100.0%	(6)	270	285	--
Carlsbad Gathering System	Texas, New Mexico	100.0%		1,008	220	--
Other (7)	Texas	Various	(8)	1,219	Various (6)	--
Total				19,586		14.2

(1) Volumes transported by these systems are regulated by governmental agencies.

(2) Of the 8,324 miles comprising the Texas Intrastate System, we lease 265 miles from a third party. We proportionately consolidate our undivided interests, which range from 22% to 80%, in 1,262 miles of pipeline. Our Wilson natural gas storage facility consists of five underground salt dome natural gas storage caverns with 12.9 Bcf of usable storage capacity, four of which (comprising 6.9 Bcf of usable capacity) are held under an operating lease that expires in January 2028. The remainder of our Texas Intrastate System is wholly owned.

(3) The Acadian Gas System is wholly owned except for an underground salt dome natural gas storage facility that we hold under an operating lease that expires in December 2018.

(4) Interstate volumes at this facility are regulated by governmental agencies.

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

(6) The Fairplay Gathering System includes approximately 52 miles of pipeline held under an operating lease.

(7) Includes our Indian Springs Gathering System (187 miles in length), Delmita Gathering System (239 miles), South Texas Gathering System (542 miles) and Big Thicket Gathering System (251 miles). The approximate net transportation capacities of each system are as follows: Indian Springs Gathering System, 160 MMcf/d; Delmita Gathering System, 145 MMcf/d; South Texas Gathering System, 143 MMcf/d; and Big Thicket Gathering System, 60 MMcf/d. Intrastate volumes transported by the Indian Springs Gathering System and Big Thicket Gathering System are regulated by governmental agencies.

(8) We proportionately consolidate our 80.0% undivided interest in the Indian Springs Gathering System. The Delmita Gathering System, South Texas Gathering System and Big Thicket Gathering System are wholly owned.

As noted previously, certain of our natural gas pipelines are subject to regulation. See "Regulatory Matters" within this Part I, Item 1 and 2 discussion for additional information regarding governmental oversight of natural gas pipelines, including tariffs charged for transportation services.

On a weighted-average basis, overall utilization rates for our onshore natural gas pipelines were approximately 65.2%, 67.7% and 64.6% during the years ended December 31, 2013, 2012 and 2011, respectively. These utilization rates represent actual natural gas volumes delivered as a percentage of our nominal delivery capacity and do not reflect firm capacity reservation agreements where throughput capacity is reserved whether or not the shipper actually utilizes such capacity.

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

§ The *Texas Intrastate System* is comprised of the 6,936-mile Enterprise Texas pipeline system, the 636-mile Channel pipeline system, the 625-mile Waha gathering system and the 127-mile TPC Offshore gathering system. The Wilson natural gas storage facility, which is an important part of the Texas Intrastate System, is comprised of a network of underground salt dome storage caverns located in Wharton County, Texas.

The Texas Intrastate System gathers, transports and stores natural gas from supply basins in Texas such as the Eagle Ford Shale and Barnett Shale for redelivery to local gas distribution companies and electric generation and industrial and municipal consumers as well as to connections with intrastate and interstate pipelines. The Texas Intrastate System serves 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 *Acadian Gas System* transports, stores and markets natural gas in Louisiana. The Acadian Gas System is comprised of the 583-mile Cypress pipeline, 419-mile Acadian pipeline, 273-mile Haynesville Extension pipeline and 26-mile Enterprise Pelican pipeline. The Acadian Gas System includes a leased underground salt dome natural gas storage cavern located at Napoleonville, Louisiana. The Acadian Gas System links natural gas supplies from Louisiana (e.g., from Haynesville Shale supply basin) and offshore Gulf of Mexico developments with local gas distribution companies, electric generation plants and industrial customers located primarily in the Baton Rouge – New Orleans – Mississippi River corridor.

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

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

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

§ The *White River Hub* is a natural gas hub facility serving producers in the Piceance Basin of northwest Colorado. The facility enables producers to access six interstate natural gas pipelines and has a gross throughput capacity of 3 Bcf/d of natural gas.

§ The *Haynesville Gathering System* consists of the 190-mile State Line gathering system, the 80-mile Southeast Mansfield gathering system and the 50-mile Southeast Stanley gathering system. The Haynesville Gathering System gathers natural gas produced from the Haynesville and Bossier Shale supply basins and the Cotton Valley and Taylor Sand formations in Louisiana and eastern Texas for delivery to regional markets, including (through an interconnect with the Haynesville Extension pipeline) markets served by our Acadian Gas System.

§ The *Fairplay Gathering System* gathers natural gas produced from the Haynesville and Bossier Shale supply basins and the Cotton Valley and Taylor Sand formations within Panola and Rusk Counties in East Texas for delivery to regional markets.

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

In addition to our natural gas pipelines, we own a natural gas treating facility (the “Central Treating Facility”) located in Rio Blanco County, Colorado. This facility can process up to 200 MMcf/d of natural gas and serves Exxon Mobil Corporation’s (“ExxonMobil”) producing properties in the Piceance Basin. Natural gas delivered to the Central Treating Facility by ExxonMobil is treated to remove impurities and transported to our Meeker gas plant for further processing.

Natural gas marketing activities. Our natural gas marketing activities generate revenues from the sale and delivery to local gas distribution companies and other customers of natural gas purchased from producers, regional natural gas processing plants and the open market. The results of operations from our natural gas marketing activities are primarily dependent upon the difference, or spread, between natural gas sales prices and the associated purchase price and other costs, including those costs attributable to the use of our other assets. In general, sales prices referenced in the underlying contracts are market-based and may include pricing differentials for factors such as delivery location.

We are exposed to commodity price risk to the extent that we take title to natural gas volumes in connection with our natural gas marketing activities and certain intrastate natural gas transportation contracts. 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 natural gas 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 natural gas price index. This index may fluctuate based on a variety of factors, including changes in natural gas supply and consumer demand. We use derivative instruments to mitigate our exposure to commodity price risks associated with our natural gas pipelines and services business.

Seasonality. Our onshore natural gas pipelines typically experience higher throughput rates during the summer months as utility companies that use natural gas for power generation increase their electricity output to meet residential and commercial demand 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. In addition, our facilities located along the U.S. Gulf Coast may be affected by weather events such as hurricanes and tropical storms, which generally arise during the summer and fall months.

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

Onshore Crude Oil Pipelines & Services

Our Onshore Crude Oil Pipelines & Services business segment includes approximately 4,600 miles of onshore crude oil pipelines, crude oil storage terminals located in Oklahoma and Texas, and our crude oil marketing activities. This business also includes a fleet of approximately 470 tractor-trailer tank trucks, the majority of which we lease and operate, that are used to transport crude oil for us and third parties.

Onshore crude oil pipelines. Our onshore crude oil pipeline systems gather and transport crude oil in New Mexico, Oklahoma and Texas to refineries, centralized storage terminals and connecting pipelines.

The results of operations from crude oil transportation services are primarily dependent upon the volume of crude oil transported and the level of fees charged to shippers (typically per barrel of crude oil). Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies, including the FERC, or contractual arrangements. Typically, revenue associated with these arrangements is recognized when volumes have been delivered; however, under certain of our crude oil pipeline transportation agreements (e.g., certain shippers on Seaway), customers are required to ship a minimum volume over an agreed-upon period, with make-up rights. Revenue pursuant to such agreements, including that associated with make-up rights, is recognized at the earlier of when the volume is shipped, when the shipper's ability to meet the minimum volume commitment has expired, or when the pipeline is otherwise released from its performance obligation.

The following table presents selected information regarding our onshore crude oil pipelines at February 1, 2014:

Description of Asset	Location(s)	Our Ownership Interest		Pipeline Length (Miles)
Crude oil pipelines:				
Seaway Pipeline (1)	Texas, Oklahoma	50.0%	(2)	633
Red River System (1)	Texas, Oklahoma	100.0%		1,769
South Texas Crude Oil Pipeline System (1)	Texas	100.0%		866
West Texas System (1)	Texas, New Mexico	100.0%		674
Basin Pipeline (1)	Texas, New Mexico, Oklahoma	13.0%	(3)	519
Eagle Ford Crude Oil Pipeline System	Texas	50.0%	(4)	175
Total miles				4,636

(1) Transportation services provided by these liquids pipelines are regulated by governmental agencies.

(2) Our ownership interest in the Seaway Pipeline is held indirectly through our equity method investment in Seaway Crude Pipeline Company LLC ("Seaway").

(3) We proportionately consolidate our undivided interest in the Basin Pipeline.

(4) Our ownership interest in the Eagle Ford Crude Oil Pipeline System is held indirectly through our equity method investment in Eagle Ford Pipeline LLC.

The maximum number of barrels per day that our onshore crude oil pipelines can transport depends on the operating balance achieved at a given point in time between various segments of each system (e.g., demand levels at each delivery point and grades of crude oil being transported) . As a result, we measure the utilization rates of our crude oil pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 1,175 MBPD, 828 MBPD and 678 MBPD during the years ended December 31, 2013, 2012 and 2011, respectively.

As noted previously, certain of our crude oil pipelines are subject to regulation. See "Regulatory Matters" within this Part I, Item 1 and 2 discussion for additional information.

The following information describes each of our principal onshore crude oil pipelines, all of which we operate with the exception of the Basin Pipeline and Eagle Ford Crude Oil Pipeline System.

§ The *Seaway Pipeline* connects the Cushing, Oklahoma crude oil hub with markets in Southeast Texas. The Seaway Pipeline is comprised of the Longhaul System, the Freeport System and the Texas City System. The Cushing hub is a major industry trading hub and price settlement point for West Texas Intermediate crude oil on the New York Mercantile Exchange.

The Longhaul System consists of an approximately 500-mile, 30-inch diameter pipeline that provides north-to-south transportation of crude oil from the Cushing hub to Seaway's Jones Creek terminal near Freeport, Texas and our terminal located near Katy, Texas. In early 2012, Seaway undertook a reversal of the flow of its Longhaul System and began providing north-to-south transportation service in May 2012. Previously, the Longhaul System was used to transport crude oil from the Jones Creek terminal to the Cushing hub (i.e., south-to-north transportation service).

We expect to complete a pipeline looping project involving our Longhaul System in the second quarter of 2014. This expansion project entails the construction of an additional 512-mile, 30-inch pipeline that will transport crude oil southbound from the Cushing hub to the Jones Creek terminal. Once this pipeline looping project is complete, the aggregate transportation capacity of the Longhaul System, including the new pipeline, is expected to be approximately 850 MBPD, depending on the type and mix of crude oil being transported and other variables.

The Freeport System consists of a marine dock, three pipelines and other related facilities that transport crude oil to and from Freeport, Texas to the Jones Creek terminal. The Texas City System consists of a marine dock, storage tanks, various pipelines and other related facilities that deliver crude oil from Texas

City, Texas to Galena Park, Texas and other nearby locations. The Freeport System and Texas City System provide intrastate transportation service. Seaway also owns storage tanks at the Jones Creek terminal that are connected to the Longhaul System. In total, the Texas City System and Jones Creek Terminal include 6.8 MMBbls of crude oil storage tank capacity (3.4 MMBbls net to our ownership interest). The intrastate transportation capacity of the Freeport System and Texas City System is approximately 220 MBPD and 800 MBPD, respectively.

In January 2013, Seaway made certain pump station additions and modifications at its Cushing origin. In January 2014, Seaway placed into service a 65-mile lateral pipeline from its Jones Creek terminal to our Enterprise Crude Houston ("ECHO") terminal. In mid-year 2014, Seaway plans to extend this lateral pipeline by approximately 100 miles to the Beaumont/Port Arthur, Texas area, which would provide shippers access to the region's heavy oil refining capabilities.

The interstate tariffs charged by Seaway to its committed and uncommitted shippers are the subject of an ongoing rate case at the FERC. For information regarding these proceedings, see "Regulatory Matters – FERC Regulation – Liquids Pipelines," within this Part I, Item 1 and 2 discussion.

§ The *Red River System* transports crude oil from North Texas and southern Oklahoma for delivery to local refineries and pipeline interconnects for further transportation to the Cushing hub. The Red River System is connected to 1.2 MMBbls of crude oil storage capacity that we own and operate.

§ The *South Texas Crude Oil Pipeline System* transports crude oil originating in South Texas, including growing production from the Eagle Ford Shale supply basin, to refineries in the Greater Houston area.

The South Texas Crude Oil Pipeline System includes our Eagle Ford Expansion pipeline, which commenced operations in June 2012 and has a crude oil transportation capacity of 350 MBPD. The Eagle Ford Expansion pipeline originates at our Lyssy station in Wilson County, Texas and extends 147 miles to Sealy, Texas. It includes 2.4 MMBbls of crude oil storage consisting of 0.2 MMBbls in Karnes County, Texas, 0.6 MMBbls in Wilson County, Texas, 0.4 MMBbls in Gonzales County, Texas and 1.2 MMBbls at Sealy. Crude oil supplies arriving at Sealy on the Eagle Ford Expansion pipeline are delivered to refiners in the Greater Houston area using affiliate and third party owned pipelines. In addition, shippers have access to our ECHO crude oil storage terminal.

Including the storage capacity associated with the Eagle Ford Expansion pipeline, the South Texas Crude Oil Pipeline System includes a total of 3.4 MMBbls of crude oil storage capacity that we own and operate.

§ The *West Texas System* connects crude oil gathering systems in West Texas and southeast New Mexico to our terminal facility in Midland, Texas. The West Texas System is connected to 0.7 MMBbls of crude oil storage capacity that we own and operate.

§ The *Basin Pipeline* transports crude oil from the Permian Basin in West Texas and southern New Mexico to the Cushing hub. The Basin Pipeline includes 5 MMBbls of crude oil storage capacity (0.8 MMBbls net to our ownership interest).

§ The *Eagle Ford Crude Oil Pipeline System* transports crude oil and condensate for producers in South Texas. This system consists of a 140-mile crude oil and condensate pipeline extending from Gardendale, Texas in LaSalle County to Three Rivers, Texas in Live Oak County and continuing on to Corpus Christi, Texas. The system also includes a 35-mile pipeline segment extending from Three Rivers to an interconnect with our South Texas Crude Oil Pipeline System in Wilson County. The Eagle Ford Crude Oil Pipeline System, which commenced operations in July 2013, has an initial transportation capacity of 300 MBPD and includes a marine terminal facility at Corpus Christi and 1.8 MMBbls of storage capacity across the system. Plains All American Pipeline, L.P. ("Plains"), our joint venture partner in the pipeline, serves as operator of the system.

In September 2013, we, along with Plains, announced an expansion of our Eagle Ford Crude Oil Pipeline System. The expansion is expected to increase the pipeline system's capacity to transport light and medium grades of crude oil from 300 MBPD to 470 MBPD in order to accommodate expected volumes from Plains' Cactus pipeline. As currently planned, the expansion of our Eagle Ford Crude Oil Pipeline System would be completed in stages that include adding pumping capacity and looping certain segments of the existing system. The expansion also includes constructing an additional 2.3 MMBbls of storage capacity at Gardendale, Tilden and Corpus Christi, Texas. We expect the expansion to be completed during the second quarter of 2015.

Crude oil terminals. We own crude oil terminals located in Oklahoma (Cushing) and Texas (Houston and Midland) that are used to store crude oil for us and our customers. The results of operations from crude oil terminal services are primarily dependent upon the level of volumes a customer stores at each terminal and the length of time such storage occurs, including the level of firm storage capacity reserved (if any), pumpover volumes and the fees associated with each activity. Fees associated with firm storage capacity reservation agreements are charged regardless of the volume the customer actually stores at the terminal.

The following table presents selected information regarding our crude oil terminals at February 1, 2014:

Description of Asset	Location(s)	Our Ownership Interest	Storage Capacity (MMBbls)
Crude oil terminals:			
Enterprise Crude Houston terminal	Texas	100.0%	0.8
Cushing terminal	Oklahoma	100.0%	3.3
Midland terminal	Texas	100.0%	1.4
Total capacity			5.5

The following information describes each of our principal crude oil storage terminals, all of which we operate.

§ The *Enterprise Crude Houston* ("ECHO") storage terminal is located in Houston, Texas and provides storage customers with access to major refiners located in the Houston and Texas City area. The ECHO terminal also has connections to marine facilities that provide connectivity to any refinery on the U.S. Gulf Coast. We developed the ECHO terminal to support the expansion of our South Texas Crude Oil Pipeline System and Seaway Pipeline.

Currently, we have 0.9 MMBbls of crude oil storage capacity at the ECHO terminal. An additional 1.1 MMBbls of storage capacity is expected to be placed in service at the terminal during the first and second quarters of 2014. As described below, we plan to expand the ECHO facility so that it will provide approximately 6.5 MMBbls of storage capacity at the site by the second quarter of 2015.

Historically, southeast Texas refineries have been supplied primarily by waterborne imports of crude oil. With the increase in North American production, crude oil from the Eagle Ford, Permian, Mid-Continent, Bakken and Canada is flowing into Southeast Texas and displacing waterborne crude oil imports. Due to growing domestic production, we expect a significant increase in North American crude oil deliveries to the Gulf Coast market, which currently lacks sufficient storage capacity and has an inadequate distribution system for handling these varying grades of domestic crude oil.

In response, we announced plans in May 2013 to significantly expand our crude oil storage and distribution infrastructure serving the southeast Texas refinery market. This planned expansion involves the construction of approximately 4.4 MMBbls of combined new crude oil storage capacity at our ECHO terminal that will increase this facility's capacity to approximately 6.5 MMBbls. Also, we plan to construct 55 miles of associated pipelines to directly connect the ECHO storage facility with several major refineries in the Southeast Texas market. The expansion would be completed in phases with final completion expected in the second quarter of 2015.

Upon completion of these projects, we will be able to provide Southeast Texas refiners with an integrated system featuring supply diversification, significant storage capabilities and a high capacity pipeline distribution system that will be directly connected to customers having an aggregate refining capacity of approximately 3.6 MMBPD.

§ The *Cushing terminal* provides crude oil storage, pumpover and trade documentation services. Our terminal in Cushing, Oklahoma has an aggregate storage capacity of 3.3 MMBbls through the use of 20 above-ground storage tanks.

§ The *Midland terminal* provides crude oil storage, pumpover and trade documentation services. The Midland, Texas terminal has an aggregate storage capacity of 1.4 MMBbls through the use of 14 above-ground storage tanks.

Crude oil marketing activities. Our crude oil marketing activities generate revenues from the sale and delivery of crude oil purchased either directly from producers or from others on the open market. The results of operations from our crude oil marketing activities are primarily dependent upon the difference, or spread, between crude oil sales prices and the associated purchase and other costs, including those costs attributable to the use of our other assets. In general, sales prices referenced in the underlying contracts are market-based and may include pricing differentials for factors such as delivery location or crude oil quality. In order to limit the exposure of our crude oil marketing activities to commodity price risk, our purchases and sales of crude oil are typically 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 activities.

Seasonality. Seasonality has little to no impact on the results of operations from our onshore crude oil pipelines and terminals. However, our crude oil assets situated along the Texas Gulf Coast (e.g., the ECHO terminal) may be affected by weather events such as hurricanes and tropical storms, which generally arise during the summer and fall months.

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

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 2,300 miles of offshore natural gas and crude oil pipelines and six offshore hub platforms.

In April 2010, in an event unrelated to our operations, the Deepwater Horizon drilling rig caught fire and sank in the Gulf of Mexico, resulting in an oil spill (also referred to as the Macondo incident). As a result, governmental agencies took actions to halt most drilling operations in the Gulf of Mexico for a period of time extending into late 2010. The moratorium impacted the timing of exploration and production activities in the Gulf of Mexico, with such activities only recently reaching pre-moratorium levels.

In general, regulations resulting from the Deepwater Horizon incident have made it more difficult for producers to obtain governmental approvals for offshore exploration and production activities. To the extent that new regulations or other governmental actions significantly curtail such exploration and production activities in the Gulf of Mexico, it could have a material adverse effect on our offshore operations.

Offshore natural gas and crude oil pipelines. Our offshore Gulf of Mexico pipelines provide for the gathering and transportation of natural gas or crude oil from offshore production fields to interconnecting offshore or onshore pipelines or processing facilities. The results of operations from these pipelines are primarily dependent upon the volume of natural gas or crude oil transported and the level of fees charged to shippers. Transportation fees are based either on contractual arrangements or, as in the case of our High Island Offshore System, tariffs regulated by the FERC. In general, contractual arrangements for offshore pipeline transportation services tend to be long-term in nature and involve life-of-reserve commitments.

The following table presents selected information regarding our offshore natural gas pipelines at February 1, 2014:

Description of Asset	Our Ownership Interest		Pipeline Length (Miles)	Approximate Net Capacity (MMcf/d) (1)
Offshore natural gas pipelines:				
Independence Trail	100.0%		135	1,000
Viosca Knoll Gathering System	100.0%		137	600
High Island Offshore System	100.0%		287	500
Falcon Natural Gas Pipeline	100.0%		14	400
Anaconda Gathering System	100.0%		183	300
Green Canyon Laterals	Various	(2)	35	213
Manta Ray Offshore Gathering System	25.7%	(3)	237	205
Nautilus System	25.7%	(3)	101	154
Nemo Gathering System	33.9%	(4)	24	102
VESCO Gathering System	13.1%	(5)	125	65
Total miles			1,278	

(1) Amounts presented are net to our ownership interest in the associated asset.
(2) We proportionately consolidate our undivided interests, which range from 2.7% to 33.3%, in 28 miles of the Green Canyon Lateral pipelines. The remainder of the laterals are wholly owned.
(3) Our ownership interests in the Manta Ray Offshore Gathering System and the Nautilus System are held indirectly through our equity method investment in Neptune Pipeline Company, L.L.C. ("Neptune"). As a result of declining pipeline throughput volumes forecast for these systems in 2014 and future years, we recorded a $4.8 million non-cash impairment charge related to our equity method investment in Neptune in 2013.
(4) Our ownership interest in the Nemo Gathering System is held indirectly through our cost method investment in Nemo Gathering Company, LLC ("Nemo").
(5) Our ownership interest in the VESCO Gathering System is held indirectly through our equity method investment in VESCO. We account for our investment in VESCO under the NGL Pipelines & Services business segment.

On a weighted-average basis, overall utilization rates for our offshore natural gas pipelines were approximately 17.7%, 21.7% and 27.4% during the years ended December 31, 2013, 2012 and 2011, respectively.

The following information describes each of our principal offshore natural gas pipelines. We operate our Independence Trail pipeline, Viosca Knoll Gathering System, High Island Offshore System, Falcon Natural Gas Pipeline, Anaconda Gathering System and certain components of the Green Canyon Laterals. Third parties operate the remainder of our offshore natural gas pipelines.

§ The *Independence Trail* pipeline transports natural gas from our Independence Hub platform and a pipeline interconnect downstream of our Independence Hub platform to the Tennessee Gas Pipeline at a pipeline interconnect on our West Delta 68 platform. Natural gas transported on the Independence Trail pipeline originates from production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico.

§ The *Viosca Knoll Gathering System* gathers natural gas from producing fields located in the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico for delivery to several major interstate pipelines, including the High Point Gas Transmission, Transco, Dauphin Island Gathering System, Tennessee Gas Pipeline and Destin Pipelines.

§ The *High Island Offshore System* ("HIOS") transports natural gas from producing fields located in the Galveston, Garden Banks, West Cameron, High Island and East Breaks areas of the Gulf of Mexico to interconnects with the ANR pipeline system and Tennessee Gas Pipeline. HIOS includes 201 miles of pipeline and eight pipeline junction and service platforms that are regulated by the FERC. In addition, this system includes the 86-mile East Breaks Gathering System, which connects HIOS to the Hoover-Diana deepwater platform located in Alaminos Canyon Block 25.

- The *Falcon Natural Gas Pipeline* transports 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* gathers natural gas from producing fields located in the Green Canyon area of the Gulf of Mexico for delivery to our Nautilus System.

- The *Green Canyon Laterals* represent a collection of small diameter pipelines that gather natural gas for delivery to HIOS and various other downstream pipelines.

- The *Manta Ray Offshore Gathering System* gathers 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 for delivery to numerous downstream pipelines, including our Nautilus System.

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

- The *Nemo Gathering System* gathers natural gas from producing fields located in the Green Canyon area of the Gulf of Mexico for delivery to an interconnect with our Manta Ray Offshore Gathering System.

- The *VESCO Gathering System* gathers natural gas from certain offshore developments for delivery to the Venice natural gas processing plant in south Louisiana.

The following table presents selected information regarding our offshore crude oil pipelines at February 1, 2014:

Description of Asset	**Our Ownership Interest**	**Length (Miles)**	**Approximate Net Capacity (MBPD)** (1)
Offshore crude oil pipelines:			
Shenzi Oil Pipeline	100.0%	83	230
Poseidon Oil Pipeline System	36.0% (2)	367	155
Cameron Highway Oil Pipeline	50.0% (3)	374	150
Allegheny Oil Pipeline	100.0%	40	140
Marco Polo Oil Pipeline	100.0%	37	120
Constitution Oil Pipeline	100.0%	67	80
Other (4)	100.0%	21	Various (4)
Total miles		989	

(1) Amounts presented are net to our ownership interest in the associated asset.
(2) Our ownership interest in the Poseidon Oil Pipeline System is held indirectly through our equity method investment in Poseidon Oil Pipeline Company, L.L.C. ("Poseidon").
(3) Our ownership interest in the Cameron Highway Oil Pipeline is held indirectly through our equity method investment in Cameron Highway Oil Pipeline Company ("Cameron Highway").
(4) Includes our Typhoon Oil Pipeline (17 miles in length) and Tarantula Oil Pipeline (4 miles). The approximate net transportation capacities of the Typhoon Oil Pipeline and Tarantula Oil Pipeline are 80 MBPD and 30 MBPD, respectively.

On a weighted-average basis, overall utilization rates for our offshore crude oil pipelines were approximately 31.3%, 30.6% and 28.4% during the years ended December 31, 2013, 2012 and 2011, respectively.

The following information describes each of our principal offshore crude oil pipelines, all of which we operate.

- The *Shenzi Oil Pipeline* gathers crude oil production from the Shenzi production field located in the Green Canyon area of the Gulf of Mexico for delivery to both our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

- The *Poseidon Oil Pipeline System* transports crude oil production from the outer continental shelf and deepwater areas of the Gulf of Mexico offshore Louisiana to onshore facilities in south Louisiana. This system includes one pipeline junction platform.

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

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

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

- The *Constitution Oil Pipeline* gathers crude oil from the Constitution, Caesar Tonga and Ticonderoga production fields located in the Green Canyon area of the Gulf of Mexico for delivery to either our Cameron Highway Oil Pipeline or Poseidon Oil Pipeline System.

In January 2012, we executed transportation agreements with six Gulf of Mexico producers that support construction of a 149-mile crude oil gathering pipeline serving the Lucius oil and gas field located in the southern Keathley Canyon area of the deepwater central Gulf of Mexico. The pipeline will be constructed and owned by Southeast Keathley Canyon Pipeline Company, L.L.C. ("SEKCO"), a 50/50 joint venture owned by us and Genesis Energy, L.P. We will serve as construction manager and operator of the new deepwater crude oil pipeline (the "SEKCO Oil Pipeline"), which is expected to have a capacity of 115 MBPD. The SEKCO Oil Pipeline is expected to begin service during the third quarter of 2014.

Offshore hub platforms. Offshore hub platforms are important components of our pipeline operations in the Gulf of Mexico. These platforms are typically used to interconnect the offshore pipeline network; provide an efficient means to perform pipeline maintenance; locate compression, separation and production handling equipment and similar assets; and conduct drilling operations during the initial development phase of an oil and natural gas property.

The results of operations from offshore platform services are primarily dependent upon the level of demand fees and/or commodity charges billable to customers. Demand fees are similar to firm capacity reservation agreements for a pipeline in that they are charged to a customer regardless of the volume the customer actually delivers to the platform. Revenue from commodity charges is based on a 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.

The following table presents selected information regarding our offshore hub platforms at February 1, 2014:

Description of Asset	Our Ownership Interest	Water Depth (Feet)	Approximate Net Capacity (1) Natural Gas (MMcf/d)	Approximate Net Capacity (1) Crude Oil (MBPD)
Offshore hub platforms:				
Independence Hub	80.0% (2)	8,000	800	N/A
Marco Polo	50.0% (3)	4,300	150	60
Viosca Knoll 817	100.0%	671	145	5
Garden Banks 72	50.0% (4)	518	113	18
East Cameron 373	100.0%	441	195	3
Falcon Nest	100.0%	389	400	3

(1) Amounts presented are net to our ownership interest.
(2) We own an 80% consolidated interest in the Independence Hub platform through our majority owned subsidiary, Independence Hub, LLC.
(3) Our ownership interest in the Marco Polo platform is held indirectly through our equity method investment in Deepwater Gateway, L.L.C. ("Deepwater Gateway").
(4) We proportionately consolidate our undivided interest in the Garden Banks 72 platform.

In addition to our offshore hub platforms, we also own or indirectly own, through our equity method investees, 13 pipeline junction and service platforms (12 of which we operate). Unlike hub platforms, pipeline junction and service platforms do not have processing capacity.

With respect to natural gas processing capacity, the overall utilization rates (on a weighted-average basis) of our offshore hub platforms were approximately 11.2%, 16.2% and 22.5% during the years ended December 31, 2013, 2012 and 2011, respectively. With respect to crude oil processing capacity, the overall utilization rates (on a weighted-average basis) of our offshore platforms were approximately 17.5%, 18.9% and 19.3% during the years ended December 31, 2013, 2012 and 2011, respectively.

The following information describes 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.

  Producers connected to our Independence Hub platform paid us $54.6 million of demand fees annually for five years beginning in March 2007 until that period expired in March 2012. We continue to receive revenues related to commodity charges from the producers.

§ The *Marco Polo* platform, which is located in Green Canyon Block 608, processes crude oil and natural gas from production fields located in the South Green Canyon area of the Gulf of Mexico.

§ The *Viosca Knoll 817* platform primarily serves as a base for gathering deepwater production in the Viosca Knoll area, including the Ram Powell development.

§ The *Garden Banks 72* platform serves as a base for gathering deepwater production from the Garden Banks area of the Gulf of Mexico. This platform also serves as a junction platform for our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

§ The *East Cameron 373* platform processes production from the Garden Banks and East Cameron areas of the Gulf of Mexico.

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

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, which generally arise during the summer and fall months. See Note 18 of the Notes to Consolidated Financial Statements included under Part II, 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.

Petrochemical & Refined Products Services

Our Petrochemical & Refined Products Services business segment includes (i) propylene fractionation and related operations, including 680 miles of pipelines; (ii) a butane isomerization complex and related pipeline assets; (iii) octane enhancement and high purity isobutylene production facilities; (iv) refined products pipelines aggregating 4,200 miles and related marketing activities; and (v) marine transportation.

Propylene fractionation and related operations. Our propylene fractionation and related operations consist of seven propylene fractionation plants, including pipeline systems aggregating approximately 680 miles in length, and related petrochemical marketing activities. This business includes an export facility and associated above-ground storage spheres for polymer grade propylene 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.

The results of operations from propylene fractionation are generally dependent upon toll processing arrangements with customers and our petrochemical marketing activities. Toll processing arrangements typically include a base processing fee per gallon (or other unit of measurement) subject to adjustment for changes in power, fuel and labor costs, all of which are the primary costs of propylene fractionation activities. The results of operations from our petrochemical pipelines are primarily dependent upon the volume of products transported and the level of fees charged to shippers. Transportation fees are based on contractual arrangements and may include provisions whereby the customer pays us a fee if certain volume thresholds are not met over a contractual term.

In our petrochemical marketing activities, we purchase refinery grade propylene on the open market for fractionation at our facilities and sell the resulting products at market-based prices. The selling price of these products may include pricing differentials for factors such as delivery location. The results of operations from our petrochemical marketing activities are primarily dependent upon the difference, or spread, between the sales prices of the products and associated purchase and other costs, including those costs attributable to the use of our other assets. As part of our petrochemical marketing activities, we have several long-term refinery grade propylene purchase and polymer grade propylene sales agreements. In order 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.

The following table presents selected information regarding our propylene fractionation facilities at February 1, 2014:

Description of Asset	Location(s)	Our Ownership Interest		Net Plant Capacity (MBPD)	Total Plant Capacity (MBPD)
Propylene fractionation facilities:					
Mont Belvieu (six units)	Texas	Various	(1)	81	95
BRPC (one unit)	Louisiana	30.0%	(2)	7	23
Total capacity				88	118

(1) We proportionately consolidate a 66.7% undivided interest in three of the propylene fractionation units, which have an aggregate 41 MBPD of total plant capacity. The remaining three propylene fractionation units are wholly owned.

(2) Our ownership interest in the BRPC facility is held indirectly through our equity method investment in Baton Rouge Propylene Concentrator LLC ("BRPC").

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. On a weighted-average basis, overall utilization rates of our propylene fractionation facilities were approximately 87.4%, 87.8% and 90.2% during the years ended December 31, 2013, 2012 and 2011, respectively.

This business includes a marine export facility located on the Houston Ship Channel at Seabrook, Texas that can load vessels at rates up to 5,000 barrels per hour. This export facility also includes above-ground storage spheres for polymer grade propylene.

The following table presents selected information regarding our petrochemical pipelines at February 1, 2014:

Description of Asset	Location(s)	Ownership Interest		Length (Miles)
Petrochemical pipelines:				
Lou-Tex and Sabine Propylene	Texas, Louisiana	100.0%		287
Texas City RGP Gathering System	Texas	100.0%		164
North Dean Pipeline System	Texas	100.0%		149
Propylene Splitter PGP Distribution System	Texas	100.0%		33
Lake Charles PGP Pipeline	Louisiana	50.0%	(1)	26
La Porte PGP Pipeline	Texas	50.0%	(2)	20
Total miles				679

(1) We proportionately consolidate our undivided interest in the Lake Charles PGP Pipeline.

(2) Our ownership interest in the La Porte PGP Pipeline is held indirectly through our equity method investments in La Porte Pipeline Company, L.P. and La Porte Pipeline GP, L.L.C.

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 delivery point in Cameron Parish, Louisiana. The North Dean Pipeline System transports refinery grade propylene from Mont Belvieu, Texas, to Point Comfort, Texas. The remainder of our petrochemical pipelines primarily transport refinery grade propylene or polymer grade propylene for customers in southeast Texas and southwest Louisiana.

The maximum number of barrels per day that our petrochemical pipelines can transport depends on the operating balance achieved at a given point in time between various segments of each system (e.g., demand levels at each delivery point and the mix of products being transported). As a result, we measure the utilization rates of our petrochemical pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes were 118 MBPD, 117 MBPD and 117 MBPD during the years ended December 31, 2013, 2012 and 2011, respectively.

In June 2012, we announced plans to build a propane dehydrogenation ("PDH") facility, with capacity to produce up to 1.65 billion pounds per year (or approximately 750 thousand metric tons per year or 25 MBPD) of polymer grade propylene. The PDH facility is expected to consume up to 35 MBPD of propane as feedstock and be located in southeast Texas along the Gulf Coast. The new facility will be integrated with our existing propylene fractionation facilities, which will provide operational reliability and flexibility for both the PDH facility and the fractionation facilities. The PDH facility will also be integrated with our polymer grade propylene storage facilities, pipeline system and export terminal. The PDH facility, which is supported by long-term, fee-based contracts, is expected to begin commercial operations during the first quarter of 2016.

Butane isomerization and deisobutanizer operations. Our Mont Belvieu complex includes three isomerization units and nine deisobutanizer ("DIB") units. Each of our isomerization units includes two reactors that convert normal butane feedstock into mixed butane, which is a stream of isobutane and normal butane. DIBs then separate the isobutane from the normal butane through fractionation. Any remaining unconverted (or residual) normal butane generated by the DIB process is then recirculated through the isomerization process until it has been converted into varying grades of isobutane, including high-purity isobutane. The isomerization process also produces natural gasoline as a by-product. We also use our DIB units to fractionate mixed butane produced from our NGL fractionators and other sources into isobutane and normal butane. Our butane isomerization assets comprise the largest commercial isomerization facility in the U.S. These operations include a 70-mile pipeline system used to transport high-purity isobutane from Mont Belvieu, Texas to Port Neches, Texas. We own and operate our butane isomerization facility and related pipeline assets.

The primary uses of isobutane are for the production of propylene oxide, isooctane, isobutylene and alkylate for motor gasoline. The demand for commercial isomerization services depends upon the industry's requirements for isobutane and high-purity isobutane in excess of the isobutane produced through the process of NGL fractionation and refinery operations. The processing capacity of our isomerization facility is 116 MBPD. On a weighted-average basis, utilization rates for this facility were approximately 81.0%, 81.9% and 87.1% during the years ended December 31, 2013, 2012 and 2011, respectively.

We use certain DIB units to fractionate mixed butanes produced from our NGL fractionation activities, from imports and from other sources into isobutane and normal butane. The operating flexibility provided by our multiple standalone DIBs enables us to take advantage of fluctuations in demand and prices for different types of butane. We measure the utilization of our standalone DIB units in terms of processing volumes, which averaged 67 MBPD, 46 MBPD and 28 MBPD for the years ended December 31, 2013, 2012 and 2011, respectively. Standalone DIB processing volumes have increased since 2011 as a result of increased NGL fractionation volumes at our Mont Belvieu complex.

The results of operation of this business are generally dependent on 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 power, fuel and labor costs, all of which are the primary costs of isomerization. These assets provide processing services to meet the needs of third party customers and our other businesses, including our NGL marketing activities and octane enhancement production facility. Our isomerization business also generates revenues from the sale of natural gasoline created as a by-product of the underlying processes.

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

In general, we sell our octane enhancement products at market-based prices. We attempt to mitigate the price risk associated with these products by entering into commodity derivative instruments. To the extent that we produce MTBE, it is sold into the export market. The production capacity of our octane enhancement facility is 12 MBPD of isooctane or 15.5 MBPD of MTBE. On a weighted-average basis, utilization rates for our octane enhancement facility were approximately 90.3%, 71% and 77.4% during the years ended December 31, 2013, 2012 and 2011, respectively.

We also own a facility located on the Houston Ship Channel that produces up to 4 MBPD of high purity isobutylene ("HPIB") and includes an associated storage facility with 0.6 MMBbls of storage capacity, 0.2 MMBbls of which is pressurized storage. The primary feedstock for this plant, an isobutane/isobutylene mix, is produced by our Mont Belvieu octane enhancement facility. HPIB is used in the formulation of polyisobutylene, which is used in the manufacture of lubricants and rubber. In general, we sell HPIB at market-based prices. On a weighted-average basis, utilization rates for this facility were 40.6%, 39.5% and 31.5% for the years ended December 31, 2013, 2012 and 2011, respectively.

Refined products pipelines and related marketing activities. Refined products pipelines and related activities include our TE Products Pipeline, an investment in Centennial Pipeline LLC ("Centennial"), and related storage, terminaling and marketing activities.

The refined petroleum products (or "refined products") transported by these pipelines are produced by refineries and primarily include motor gasoline. The results of operations from our refined products pipelines are primarily dependent upon the volume of products transported and the level of fees charged to shippers. The tariffs charged for such services are either contractual or regulated by governmental agencies, including the FERC. The results of our storage and terminal assets are primarily dependent on the volume stored or otherwise handled and the associated fees charged.

Our refined products marketing activities generate revenues from the sale and delivery of refined products obtained on the open market. The results of operations from our refined products marketing activities are primarily dependent upon the difference, or spread, between product sales prices and the associated purchase and other costs, including those costs attributable to the use of our other assets. In general, we sell our refined products at market-based prices, which may include pricing differentials for factors such as delivery location. We use derivative instruments to mitigate our exposure to commodity price risks associated with our refined products marketing activities.

The following table presents selected information regarding our refined products pipelines and related terminal and storage assets at February 1, 2014:

Description of Asset	Location(s)	Our Ownership Interest		Length (Miles)	Net Usable Storage Capacity (MMBbls)
Refined products pipelines and terminals:					
TE Products Pipeline (1,2)	Texas to Midwest and Northeast U.S.	100.0%		3,420	18.2
Centennial Pipeline (2)	Texas to central Illinois	50.0%	(3)	795	1.2
Other terminals (4)	Alabama, Mississippi, Texas	100.0%		n/a	0.6
Total				4,215	20.0

(1) In addition to the 18.2 MMBbls of refined products storage capacity presented in the table, we have 3.7 MMBbls of NGL storage capacity that is used to support operations on our TE Products Pipeline. Our NGL storage and terminal assets are accounted for under our NGL Pipelines & Services business segment.

(2) Interstate and intrastate transportation services provided by the TE Products Pipeline and interstate transportation services provided by the Centennial Pipeline are regulated by governmental agencies.

(3) Our ownership interest in the Centennial Pipeline is held indirectly through our equity method investment in Centennial.

(4) Includes product distribution and marketing terminals located in Aberdeen, Mississippi and Boligee, Alabama having storage capacities of 0.1 MMBbls and 0.5 MMBbls, respectively.

The maximum number of barrels per day that our refined products pipelines can transport depends on the operating balance achieved at a given point in time between various segments of each system (e.g., demand levels at each delivery point and the mix of products being transported). As a result, we measure the utilization rates of our refined products pipelines in terms of net throughput, which is based on our ownership interest. Aggregate net throughput volumes by product type for the TE Products Pipeline and Centennial Pipeline were as follows for the periods presented:

	For Year Ended December 31,		
	2013	**2012**	**2011**
Refined products transportation (MBPD)	373	383	429
Petrochemical transportation (MBPD)	120	101	121
NGL transportation (MBPD)	72	66	92

As a result of increased refinery production in the Midwest and Northeast U.S. markets served by our refined products pipelines along with lower overall demand for refined products in these regions, demand to transport refined products from the Gulf Coast to these markets has decreased. As discussed below, we have repurposed significant components of our TE Products Pipeline to accommodate the southbound delivery of ethane by the ATEX Express pipeline.

As noted previously, these pipelines are subject to regulation. See "Regulatory Matters" within this Part I, Item 1 and 2 discussion for additional information regarding governmental oversight of liquids pipelines, including tariffs charged for transportation services.

The following information describes each of our principal refined products pipelines. With the exception of the Centennial Pipeline, we operate our refined products pipelines and associated facilities.

§ The *TE Products Pipeline* is a 3,420-mile pipeline system comprised of 3,102 miles of interstate pipelines and 318 miles of intrastate Texas pipelines. Refined products and certain NGLs are transported from the upper Texas Gulf Coast to Seymour, Indiana. From Seymour, segments of the TE Products Pipeline extend to Chicago, Illinois; Lima, Ohio; Selkirk, New York; and near Philadelphia, Pennsylvania. East of Todhunter, Ohio, the TE Products Pipeline is primarily dedicated to NGL transportation service.

Products are delivered to various locations along the system, including terminals owned either by us or third parties and to various connecting pipelines. Enterprise operates five refined products truck terminals and various storage facilities located along the TE Products Pipeline.

In January 2014, our ATEX Express pipeline commenced operations. In addition to new construction, this project involved repurposing components of the TE Products Pipeline to accommodate southbound delivery of ethane to the U.S. Gulf Coast. The repurposed pipeline assets were reclassified to the NGL Pipelines & Services business segment (on a prospective basis in January 2014) when ATEX Express commenced operations. Pipeline assets that continue to be utilized by the TE Products Pipeline remain in the Petrochemical & Refined Products Services business segment.

§ The *Centennial Pipeline* is a refined products pipeline that extends from an origination facility located on our TE Products Pipeline in Beaumont, Texas, to Bourbon, Illinois. The Centennial Pipeline includes a refined products storage terminal located near Creal Springs, Illinois with a gross storage capacity of 2.3 MMBbls (or 1.2 MMBbls net to our ownership interest).

Marine transportation. Our marine transportation business consists of tow boats and tank barges that are used to transport refined products, crude oil, asphalt, condensate, heavy fuel oil, liquefied petroleum gas and other petroleum products along key inland and intracoastal U.S. waterways. The marine transportation industry uses tow boats as power sources and tank barges for freight capacity. We refer to the combination of the power source and freight capacity as a tow. Our inland tows generally consist of one tow boat paired with up to four tank barges, depending upon the horsepower of the tow boat, location, waterway conditions, customer requirements and prudent operational considerations. Our offshore tows generally consist of one tow boat and one ocean-certified tank barge.

Our marine transportation assets service refinery and storage terminal customers along the Mississippi River, the intracoastal waterway between Texas and Florida and the Tennessee-Tombigbee Waterway system. We own a shipyard and repair facility located in Houma, Louisiana and marine fleeting facilities located in Bourg, Louisiana and Channelview, Texas. The results of operations of our marine transportation business are generally dependent upon the level of fees charged to transport cargo. These transportation services are typically provided under term contracts (also referred to as affreightment contracts), which are agreements with specific customers to transport cargo from within designated operating areas at either set day rates or a set fee per cargo movement.

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. For additional information regarding these regulations, see "Regulatory Matters – Federal Regulation of Marine Operations," within this Part I, Item 1 and 2 discussion.

The following table presents selected information regarding our marine transportation assets at February 1, 2014:

Class of Equipment	**Number in Class**	**Capacity/ Horsepower (as indicated by sign)** (1)
Inland marine transportation assets:		
Barges	10	< 25,000 bbls
Barges	111	> 25,000 bbls
Tow boats	20	< 2,000 hp
Tow boats	35	≥ 2,000 hp
Offshore marine transportation assets:		
Ocean-certified tank barges	8	≥ 20,000 bbls
Tow boats	1	< 2,000 hp
Tow boats	5	> 2,000 hp

(1) As used in this table, references to "bbls" means barrels and "hp" means horsepower.

Our fleet of marine vessels operated at an average utilization rate of 93.9%, 90.9% and 91.8% during the years ended December 31, 2013, 2012 and 2011, respectively.

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 from April to September of each year when motor gasoline demand increases in connection with the summer driving season.

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 TE Products Pipeline are generally higher from October through March due to higher demand for propane (for residential heating purposes) and normal butane (for blending in motor gasoline).

Our marine transportation business exhibits some seasonal variation. Demand for motor gasoline is generally stronger in the spring and summer months due to the summer driving season. Weather events, such as hurricanes and tropical storms in the Gulf of Mexico, can adversely impact both the offshore and inland marine transportation business. Also, cold weather and ice during the winter months can negatively impact our inland marine 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 supporting pipeline and storage infrastructure. We compete with other octane additive manufacturing companies primarily on the basis of price.

With respect to our TE Products Pipeline, its 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 markets served by our TE Products Pipeline and river terminals. The TE Products Pipeline faces competition from rail and pipeline movements of NGLs from Canada and waterborne imports into terminals located along the upper East Coast.

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

Title to Properties

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

Regulatory Matters

The following information describes the principal effects of regulation on our business activities, including those regulations involving safety and environmental matters and the rates we charge customers for transportation services.

Safety Matters

The safe operation of our pipelines and other assets is a top priority of our partnership. We are committed to protecting the environment and the health and safety of the public and those working on our behalf by conducting our business activities in a safe and environmentally responsible manner.

Occupational Safety and Health. Certain of our facilities are subject to the general industry requirements of the Federal Occupational Safety and Health Act, as amended (“OSHA”), and comparable state statutes. We believe we are in material compliance with OSHA and the similar state requirements, including general industry standards, record keeping requirements and monitoring of occupational exposures of employees.

Certain of our facilities are subject to OSHA Process Safety Management (“PSM”) regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process involving a chemical at or above a specified threshold (as defined in the regulations) or any process which involves certain flammable gases or liquids. In addition, we are subject to the Risk Management Plan regulations of the U.S. Environmental Protection Agency ("EPA") at certain facilities. These regulations are intended to complement the OSHA PSM regulations. These EPA 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 the OSHA PSM regulations and the EPA's Risk Management Plan requirements.

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

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

We are also subject to DOT regulations requiring pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. The intent of these regulations is to ensure a qualified work force and to reduce the probability of accidents caused by human error and their consequences. In addition, DOT regulations require pipeline operators to institute certain pipeline control room procedures. We believe we are in material compliance with these DOT regulations.

We are also subject to DOT pipeline integrity management regulations that 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 include populated areas, unusually sensitive areas and commercially navigable waterways. The regulation requires the development and implementation of an integrity management program that utilizes internal pipeline inspection techniques, pressure testing or other equally effective means to assess the integrity of pipeline segments in HCAs. These regulations also require 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 in the assessment and analysis process. We have identified our pipeline segments in HCAs and developed an appropriate integrity management program for such assets.

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

The DOT also issued an Advance Notice of Proposed Rulemaking in October 2010 in Docket No. PHMSA-2010-0229 in which it is considering whether to remove or modify regulatory exemptions that currently exist in the pipeline safety regulations for the gathering of hazardous liquids by pipelines in rural areas. The comment period for this notice ended in February 2011; however, we cannot predict the ultimate impact of the proposed changes on our operations at this time.

In total, our pipeline integrity costs for the years ended December 31, 2013, 2012 and 2011 were $124.3 million, $146.6 million and $117.3 million, respectively. Of these annual totals, we charged $66.7 million, $67.2 million and $64.7 million to operating costs and expenses during the years ended December 31, 2013, 2012 and 2011, respectively. The remaining annual pipeline integrity costs were capitalized and treated as sustaining capital projects. We expect the cost of our pipeline integrity program, regardless of whether such costs are capitalized or expensed, to approximate $137.0 million for 2014.

The American Petroleum Institute Standard 653 (“API 653”) is an industry standard for the inspection, repair, alteration and reconstruction of storage tanks. API 653 requires regularly scheduled inspection and repair of such tanks. These periodic tank maintenance requirements may result in 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 Matters

Our operations are subject to various environmental and safety requirements and potential liabilities under extensive federal, state and local laws and regulations. These include, without limitation: CERCLA; the Resource Conservation and Recovery Act (“RCRA”); the Federal Clean Air Act (“CAA”); the Clean Water Act (“CWA”); the Oil Pollution Act of 1990 (“OPA”); OSHA; the Emergency Planning and Community Right to Know Act; and comparable or analogous state and local laws and regulations. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals with respect to air emissions, water quality, wastewater discharges and solid and hazardous waste management. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could have a material adverse effect on our financial position, results of operations and cash flows.

If a leak, spill or release of hazardous substances occurs at any facilities that we own, operate or otherwise use, or where we send materials for treatment or disposal, we could be held liable for all resulting liabilities, including investigation, remedial and clean-up costs. Likewise, we could be required to remove previously disposed waste products or remediate contaminated property, including situations where groundwater has been impacted. Any or all of these developments could have a material adverse effect on our financial position, results of operations and cash flows.

We believe our operations are in material compliance with applicable environmental and safety laws and regulations. In addition, we expect that compliance with existing environmental and safety laws and regulations will not have a material adverse effect on our financial position, results of operations and cash flows. However, environmental and safety laws and regulations are subject to change. The trend in environmental regulation has been to place more restrictions and limitations on activities that may be perceived to impact 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. New or revised regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our financial position, results of operations and cash flows.

On occasion, we are assessed monetary sanctions by governmental authorities related to administrative or judicial proceedings involving environmental matters. See Part I, Item 3 of this annual report for additional information.

Air Quality. Our operations are associated with regulatory permitted emissions of air pollutants. As a result, we are subject to the CAA and comparable state laws and regulations including state air quality implementation plans. These laws and regulations regulate emissions of air pollutants from various industrial sources, including certain of our facilities, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in an increase in existing air emissions, obtain and strictly comply with the requirements of air permits containing various emission and operational limitations, or utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and enforcement actions. We may be required to incur certain capital expenditures for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

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

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

Contamination resulting from spills or releases of petroleum products is an inherent risk within the pipeline industry. To the extent that groundwater contamination requiring remediation exists along our pipeline systems or other facilities as a result of past operations, we believe any such contamination could be controlled or remedied without having a material adverse effect on our financial position, results of operations and cash flows, but such costs are site specific and there is no assurance that the impact will not be material in the aggregate.

Environmental groups have instituted lawsuits regarding certain nationwide permits issued by the Army Corps of Engineers. These permits allow for streamlined permitting of pipeline projects. If these lawsuits are successful, timelines for future pipeline construction projects could be adversely impacted.

Disposal of Hazardous and Non-Hazardous Wastes. 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 solid waste. We also utilize waste minimization and recycling processes to reduce the volumes of our solid wastes.

CERCLA, also known as "Superfund," imposes liability, often without regard to fault or the legality of the original act, on certain classes of persons who contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of a facility where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at a facility. Under CERCLA, responsible parties may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA and RCRA also authorize the EPA and, in some instances, third parties to take actions in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible parties. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our ordinary operations, our pipeline systems and other facilities generate wastes that may fall within CERCLA's definition of a "hazardous substance" or be subject to CERCLA and RCRA remediation requirements. It is possible that we could incur liability for remediation or reimbursement of remediation costs under CERCLA or RCRA for remediation at sites we currently own or operate, whether as a result of our or our predecessors' operations, at sites that we previously owned or operated, or at disposal facilities previously used by us, even if such disposal was legal at the time it was undertaken.

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

FERC Regulation

Liquids Pipelines. Certain of our natural gas liquids, petroleum products and crude oil pipeline systems are interstate common carriers subject to regulation by the FERC under the Interstate Commerce Act ("ICA"). These pipelines (referred to as "interstate liquids pipelines") include, but are not limited to, the following principal assets: ATEX Express, Dixie System, Enterprise TE Products Pipeline, Front Range Pipeline, Mid-America Pipeline System, Seaway Pipeline, Seminole Pipeline and Texas Express Pipeline.

The ICA prescribes that the interstate rates we charge for transportation on these interstate liquids pipelines must be just and reasonable, and that the rules applied to our services not unduly discriminate against or confer any undue preference upon any shipper. FERC regulations implementing the ICA further require that interstate liquids pipeline transportation rates and rules be filed with the FERC. 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. Upon completion of such an investigation, the FERC may require refunds of amounts collected above what it finds to be a just and reasonable level, together with interest. 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 (including interest) for damages sustained for a period of up to two years prior to the filing of its complaint.

The rates charged for our interstate liquids pipeline services are generally based on a FERC-approved indexing methodology, which allows a pipeline to charge rates up to a prescribed ceiling that changes annually based on the year-to-year change in the U.S. 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 operating costs. During the five-year period commencing July 1, 2011 and ending June 30, 2016, we have been permitted by FERC to adjust these indexed rate ceilings annually by the PPI plus 2.65%. As an alternative to this indexing methodology, we may also choose to support our rates based on a cost-of-service methodology, or by obtaining advance approval to charge "market-based rates," or by charging "settlement rates" agreed to by all affected shippers.

The initial rates charged to shippers for crude petroleum transportation services from Cushing, Oklahoma to the Gulf Coast on the Seaway Pipeline are being collected subject to refund and to the outcome of an ongoing FERC rate proceeding. Seaway is charging "committed shipper" rates to shippers who voluntarily agreed under long term contracts to commit to the transportation of, or nevertheless to pay for (to the extent not transported) the transportation of, a minimum volume of crude petroleum. Seaway is also charging "uncommitted shipper" rates to shippers who have not made any long term contractual commitment to the Seaway Pipeline and instead receive service month to month. The committed shipper rates are lower than the uncommitted shipper rates and are an incentive to enter into long term transportation agreements. In March 2013, the FERC issued an order stating that the charging by a pipeline of voluntarily agreed-to committed shipper rates is consistent with the FERC's policy of honoring contracts (the "March 2013 Order"). In light of the March 2013 Order, we believe that Seaway's committed shipper rates are not at issue in the ongoing rate proceeding. However, in September 2013, an administrative law judge ("ALJ") issued an initial decision in the rate proceeding distinguishing the March 2013 Order and recommending that the FERC find, among other things, that Seaway's committed and uncommitted shipper rates are not just and reasonable and should be re-determined on a cost of service basis. In October 2013, Seaway and certain committed rate shippers filed briefs on exception objecting to this aspect of the ALJ's initial decision. On February 28, 2014, the FERC reiterated its policy of honoring contracts executed between pipelines and committed shippers. The February 2014 order reversed the ALJ's September 2013 initial decision on the committed rates. A FERC order addressing the rates we charge uncommitted shippers is still pending and we are unable to predict its ultimate outcome.

In February 2014, the FERC upheld an order it issued in May 2012 that denied Seaway's initial application for market-based rate setting authority, without prejudice to Seaway refiling its application based on the guidance provided in the February order. We are reviewing our options in responding to this recent FERC decision. In light of the complex nature of these FERC actions, we are unable to predict their ultimate outcome on the rates Seaway charges its shippers.

Changes in the FERC's methodologies for approving rates could adversely affect us. In addition, challenges to our regulated rates could be filed with the FERC and future decisions by the FERC regarding our regulated rates could adversely affect our cash flows. We believe the transportation rates currently charged by our interstate liquids pipelines are in accordance with the ICA and applicable FERC regulations. However, we cannot predict the rates we will be allowed to charge in the future for transportation services by such pipelines.

Natural Gas Pipelines and Related Matters. Certain of our intrastate natural gas pipelines, including our Texas Intrastate System and our Acadian Gas System, are subject to limited regulation by the FERC under the Natural Gas Policy Act of 1978 ("NGPA"), in connection with the transportation and storage services they provide pursuant to Section 311 of the NGPA. Under Section 311 of the NGPA, and the FERC's implementing regulations, 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 broader regulatory authority under Natural Gas Act of 1938("NGA"). These services must be provided on an open and nondiscriminatory basis, and the rates charged for these services may not exceed a "fair and equitable" level as determined by the FERC in periodic rate proceedings. Our HIOS pipeline is regulated by the FERC under the NGA. The NGA prescribes that transportation rates charged by pipelines be just and reasonable and that service not be provided on an unduly discriminatory basis. Rates may be lowered on a prospective basis by the FERC if it finds, on its own initiative or as a result of challenges to the rates by shippers, that they are unjust, unreasonable or otherwise unlawful.

We believe that the transportation rates currently charged and the services performed by our natural gas pipelines are all in accordance with the applicable requirements of the NGA, the NGPA, and FERC regulations. However, we cannot predict the rates we will be allowed to charge in the future for transportation services by our pipelines.

The resale of natural gas in interstate commerce is subject to FERC oversight. In order to increase transparency in natural gas markets, the FERC has established rules requiring the annual reporting of data regarding natural gas sales. The FERC has also established regulations that prohibit energy market manipulation. The Federal Trade Commission and the Commodity Futures Trading Commission have also issued rules and regulations prohibiting energy market manipulation. We believe that our gas sales activities are in compliance with all applicable regulatory requirements.

A violation of the FERC's regulations may subject us to civil penalties, suspension or loss of authorization to perform services or make sales of natural gas, disgorgement of unjust profits or other appropriate non-monetary remedies imposed by the FERC. Pursuant to the Energy Policy Act of 2005, the potential civil and criminal penalties for any violation of the NGA, the NGPA, or any rules, regulations or orders of the FERC, were increased to up to $1 million per day per violation.

State Regulation of Pipeline Transportation Services

Transportation services rendered by our intrastate liquids and natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Illinois, Kansas, Louisiana, Minnesota, Mississippi, New Mexico, Oklahoma, Texas and Wyoming. The Texas Railroad Commission has the authority to regulate the rates and terms of service for our intrastate natural gas transportation operations in Texas. 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 tariff rates and practices on our intrastate pipelines.

Federal Regulation of Marine Operations

The operation of tow boats, barges and marine equipment create maritime obligations involving property, personnel and cargo under General Maritime Law. These obligations create a variety of risks including, 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.

We are subject to the Jones Act and other federal laws that restrict maritime transportation between U.S. departure and destination points to vessels built and registered in the U.S. and owned and manned by U.S. citizens. As a result of this ownership requirement, we are responsible for monitoring the foreign ownership of our common units and other partnership interests. If we do not comply with such requirements, we would be prohibited from operating our vessels in U.S. coastwise trade, and under certain circumstances we would be deemed to have undertaken an unapproved foreign transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of the vessels. In addition, the USCG and American Bureau of Shipping maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for U.S.-flag operators than for owners of vessels registered under foreign flags of convenience. Our marine operations are also subject to the Merchant Marine Act of 1936, which under certain conditions would allow the U.S. government to requisition our marine assets in the event of a national emergency.

Climate Change Debate

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

In response to scientific studies suggesting that emissions of certain gases, commonly referred to as greenhouse gases, including gases associated with oil and gas production such as carbon dioxide, methane and nitrous oxide among others, may be contributing to a warming of the earth's atmosphere and other adverse environmental effects, various governmental authorities have considered or taken actions to reduce emissions of greenhouse gases. For example, the EPA has taken action under the CAA to regulate greenhouse gas emissions. In addition, certain states, including states in which some of our facilities or operations are located, have taken or proposed measures to reduce emissions of greenhouse gases. Also, the U.S. Congress has proposed legislative measures for imposing restrictions or requiring emissions fees for greenhouse gases. However, there have been no federal regulations enacted to date that specifically restrict greenhouse gas emissions, which has resulted in certain states and regional partnerships taking the initiative. While the state specific efforts seem less burdensome, any such legislation may have the potential to affect our business, customers or the energy sector in general.

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

Following the U.S. Supreme Court's decision in *Massachusetts, et al. v. EPA*, 549 U.S. 497 (2007), finding that greenhouse gases fall within the CAA definition of "air pollutant," the EPA determined that greenhouse gases from certain sources "endanger" public health or welfare. As a result, the EPA has taken the position that existing CAA provisions require an assessment of greenhouse gas emissions within the permitting process for certain large new or modified stationary sources under the EPA's Prevention of Significant Deterioration ("PSD") and Title V permit programs beginning in 2011. If deemed cost-effective, facilities that trigger permit requirements may be required to reduce greenhouse gas emissions consistent with the "best available control technology" standards. Such changes will also affect state air permitting programs in states that administer the CAA under a delegation of authority, including states in which we have operations. Additionally, in November 2010, the EPA finalized rules expanding its Mandatory Greenhouse Gas Reporting Rule, originally promulgated in October 2009, to be applicable to the oil and natural gas industry. The expansion requires annual, on-site monitoring and additional inventory and reporting of greenhouse gas emissions and affects many of our existing operations and must be considered when planning for future operations. Although subject to legal challenge, the EPA rules promulgated thus far are currently final and effective, and will remain so unless the regulations are overturned by a court ruling, or Congress adopts legislation altering the EPA's regulatory authority.

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

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

Available Information

As a publicly traded partnership, we electronically file certain documents with the 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 a website at www.sec.gov that contains reports and other information regarding registrants that file electronically with the SEC.

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

Item 1A. *Risk Factors*.

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

Risks Relating to Our Business

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

On a standalone basis, Enterprise Products Partners L.P. is a holding company with no business operations and conducts all of its business through its wholly owned subsidiary, EPO. As a result, we depend upon the earnings and cash flows of EPO and its subsidiaries and joint ventures, and the distribution of their cash flows to us in order to meet our obligations and to allow us to make cash distributions to our partners.

The amount of cash EPO and its subsidiaries and joint ventures can distribute to us depends primarily on cash flows generated from their operations. These operating cash flows fluctuate from quarter-to-quarter based on, among other things, the: (i) volume of hydrocarbon products transported on their gathering and transmission pipelines; (ii) throughput volumes in their processing and treating operations; (iii) fees charged and the margins realized for their various storage, terminaling, processing and transportation services; (iv) price of natural gas, crude oil and NGLs; (v) relationships among natural gas, crude oil and NGL prices, including differentials between regional markets; (vi) fluctuations in their working capital needs; (vii) level of their operating costs; (viii) prevailing economic conditions; and (ix) level of competition encountered by their businesses. In addition, the actual amount of cash EPO and its subsidiaries and joint ventures will have available for distribution will depend on factors such as: (a) the level of sustaining capital expenditures incurred; (b) their cash outlays for expansion (or growth) capital projects and acquisitions; and (c) their debt service requirements and restrictions included in the provisions of existing and future indebtedness, charter documents, applicable state partnership and limited liability company laws and other applicable laws and regulations. Because of these factors, we may not have sufficient available cash each quarter to continue paying distributions at our current levels.

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

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

We operate predominantly in the midstream energy industry, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs, crude oil, petrochemical and refined products. As such, changes in the prices of hydrocarbon products and in the relative price levels among hydrocarbon products could have a material adverse effect on our financial position, results of operations and cash flows. Changes in prices may impact demand for hydrocarbon products, which in turn may impact production, demand and the volumes of products for which we provide services. In addition, decreases in demand may be caused by other factors, including prevailing economic conditions, reduced demand by consumers for the end products made with hydrocarbon products, increased competition, adverse weather conditions and government regulations affecting prices and production levels. We may also incur credit and price risk to the extent counterparties do not fulfill their obligations to us in connection with our marketing of natural gas, NGLs, propylene, refined products and/or crude oil.

In recent years, the price of natural gas and ethane has been volatile, and we expect this volatility to continue. The New York Mercantile Exchange ("NYMEX") daily settlement price for natural gas for the prompt month futures contract ranged: in 2011, from a high of $4.85 per MMBtu to a low of $2.99 per MMBtu; in 2012, from a high of $3.90 per MMBtu to a low of $1.91 per MMBtu; and in 2013, from a high of $4.46 per MMBtu to a low of $3.11 per MMBtu. Due to oversupply conditions, the average market price of ethane (based on prices at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production) has declined from $0.77 per gallon in 2011 to $0.40 per gallon in 2012 and further to $0.26 per gallon in 2013.

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

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

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

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

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

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

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

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

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

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

As of December 31, 2013, we had $15.35 billion in principal amount of consolidated senior long-term debt outstanding, $1.53 billion in principal amount of junior subordinated debt outstanding and $475.0 million in short-term commercial paper notes outstanding. The amount of our future debt could have significant effects on our operations, including, among other things:

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

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

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

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

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

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

Our public debt indentures currently do not limit the amount of future indebtedness that we can incur, assume or guarantee. Although our credit agreements restrict our ability to incur additional debt above certain levels, any debt we may incur in compliance with these restrictions may still be substantial. For information regarding our long-term debt, see Note 11 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

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

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

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

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

We will require substantial new capital to finance the future development and acquisition of assets and businesses. For example, for the year ended December 31, 2013, we spent $4.48 billion on capital projects, including those in the Eagle Ford Shale, at our Mont Belvieu complex, expansion of our joint venture crude oil pipelines and construction of the ATEX Express pipeline. Based on information currently available, we expect total capital spending for 2014 to be in the range of $3.9 billion to $4.4 billion, which includes $350 million for sustaining capital expenditures. Any limitations on our access to capital may impair our ability to execute this growth strategy. If our cost of debt or equity capital becomes too expensive, our ability to develop or acquire accretive assets will be limited. We also may not be able to raise the necessary funds on satisfactory terms, if at all.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

We believe that EPCO maintains adequate insurance coverage on our behalf, although insurance will not cover many types of interruptions that might occur, will not cover amounts up to applicable deductibles and will not cover all risks associated with certain of our products. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. For example, we elected to forego windstorm coverage for our Gulf of Mexico offshore assets during the 2013 Atlantic hurricane season, which extends from June 1 through November 30. The combination of increasingly high deductibles and proposed higher premiums resulted in such coverage being uneconomic to us. Although EPCO's coverage does not provide any windstorm coverage for our offshore assets during the annual policy period that began on June 1, 2013, we expect that producers affiliated with our Independence Hub and Marco Polo platforms will continue to provide certain levels of physical damage windstorm coverage for each of these key offshore assets.

In the future, circumstances may arise whereby EPCO may not be able to renew existing insurance policies on our behalf or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

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

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

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

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

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

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

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

Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base. Our largest non-affiliated customer for 2013 and 2012 was BP p.l.c. and its affiliates, which accounted for 9.0% of our consolidated revenues in 2013 and 9.5% of our consolidated revenues in 2012. Shell Oil Company and its affiliates was our largest non-affiliated customer in 2011, accounting for 10.6% of our consolidated revenues for that year.

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

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

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

Our variable-rate debt, including those fixed-rate debt obligations converted to variable-rate through the use of interest rate swaps, make us vulnerable to increases in interest rates, which could have a material adverse effect on our financial position, results of operation and cash flows.

As of December 31, 2013, we had $16.88 billion in principal amount of consolidated long-term debt outstanding, including current maturities thereof. Of this amount, approximately $150.0 million, or 1%, 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.

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

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

Our pipeline integrity program as well as compliance with pipeline safety laws and regulations may impose significant costs and liabilities on us.

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

In January 2012, President Obama signed the 2011 Pipeline Safety Act into law. The 2011 Pipeline Safety Act provides, among other things, for additional regulatory oversight of the nation's pipelines, increases the penalties for violations of pipeline safety rules, and complements the DOT's other initiatives. For additional information regarding the pipeline safety regulations and the 2011 Pipeline Safety Act, see "Regulatory Matters—Safety Matters—Pipeline Safety" included under Part I, Item 1 and 2 of this annual report.

If we were to incur material costs in connection with our pipeline integrity program or pipeline safety laws and regulations, those costs could have a material adverse effect on our financial condition, results of operations and cash flows.

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

Our operations are subject to various environmental, health and safety requirements and potential liabilities under extensive federal, state and local laws and regulations. Further, we cannot ensure that existing environmental, health and safety regulations will not be revised or that new regulations will not be adopted or become applicable to us. Governmental authorities have the power to enforce compliance with applicable regulations and permits and to subject violators to civil and criminal penalties, including substantial fines, injunctions or both. Certain environmental laws, including CERCLA and analogous state laws and regulations, may impose strict, joint and several liability for costs required to clean-up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, third parties, including neighboring landowners, may also have the right to pursue legal actions to enforce compliance or to recover for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could have a material adverse effect on our financial position, results of operations and cash flows.

In addition, future environmental, health and safety law developments, such as stricter laws, regulations, permits or enforcement policies, could significantly increase some costs of our operations. Areas of potential future environmental, health and safety law development include the following items.

Greenhouse Gases / Climate Change. Responding to scientific reports regarding threats posed by global climate change, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases. In addition, some states, including states in which our facilities or operations are located, have individually or in regional cooperation, imposed restrictions on greenhouse gas emissions under various policies and approaches, including establishing a cap on emissions, requiring efficiency measures, or providing incentives for pollution reduction, use of renewable energy sources, or use of replacement fuels with lower carbon content. The adoption and implementation of any federal, state or local regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur significant costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the crude oil, natural gas or other hydrocarbon products that we transport, store or otherwise handle in connection with our midstream services. The potential increase in our operating costs could include costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions, and administer and manage a greenhouse gas emissions program. We may not be able to recover such increased costs through customer prices or rates. In addition, changes in regulatory policies that result in a reduction in the demand for hydrocarbon products that are deemed to contribute to greenhouse gases, or restrictions on their use, may reduce volumes available to us for processing, transportation, marketing and storage. These developments could have a material adverse effect on our financial position, results of operations and cash flows.

Hydraulic Fracturing. Certain of our customers employ hydraulic fracturing techniques to stimulate natural gas and crude oil production from unconventional geological formations (including shale formations), which entails the injection of pressurized fracturing fluids (consisting of water, sand and certain chemicals) into a well bore. The U.S. federal government, and some states and localities, have adopted, and others are considering adopting, regulations or ordinances that could restrict hydraulic fracturing in certain circumstances, or that would impose higher taxes, fees or royalties on natural gas production. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and gas drilling activities using hydraulic fracturing techniques, including increased litigation. Additional legislation or regulation could also lead to operational delays and/or increased operating costs in the production of oil and natural gas (including natural gas produced from shale plays like the Eagle Ford, Haynesville, Barnett, Marcellus and Utica Shales) incurred by our customers or could make it more difficult to perform hydraulic fracturing. If these legislative and regulatory initiatives cause a material decrease in the drilling of new wells and related servicing activities, it may affect the volume of hydrocarbon projects available to our midstream business and have a material adverse effect on our financial position, results of operations and cash flows.

Offshore Drilling. Offshore drilling involves additional risks and different regulations than onshore drilling. Since the Deepwater Horizon oil spill in the Gulf of Mexico during 2010, an event unrelated to our operations, the U.S. Department of Interior (the "Interior Department") and state regulatory authorities have promulgated substantial additional regulations, including regulations relating to the approval of new permits to drill, the enhanced inspections of oil and gas rigs and more stringent preparedness plans. These new regulatory requirements have added, and may continue to add, delays in the permitting of offshore wells and costs in the planning, permitting, development and operation of new and existing wells by our customers. A decline in, or failure to achieve anticipated volumes of oil and natural gas supplies due to any of these factors could have a material adverse effect on our financial position, results of operations and cash flows.

Please read "Regulatory Matters" under Part I, Item 1 and 2 of this annual report for more information and specific disclosures relating to environmental, health and safety laws and regulations, and costs and liabilities.

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

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

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

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

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

For a general overview of federal, state and local regulation applicable to our assets, see "Regulatory Matters" included within Part I, Item 1 and 2 of this annual report. This regulatory oversight can affect certain aspects of our business and the market for our products and could have a material adverse effect on our financial position, results of operations and cash flows.

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

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

The FERC uses prescribed rate methodologies for approving regulated tariff rate changes for interstate liquids pipelines. The FERC's indexing methodology currently allows a pipeline to increase its rates by a percentage linked to the PPI. As an alternative to this indexing methodology, we may also choose to support our rates based on a cost-of-service methodology, or by obtaining advance approval to charge "market-based rates," or by charging "settlement rates" agreed to by all affected shippers. 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.

In addition, the FERC, pursuant to the NGA, and rules and regulations promulgated thereunder, regulates the rates for our interstate natural gas pipeline. These rates must be just and reasonable and not unduly discriminatory. Existing pipeline rates may be challenged by customer complaint or by the FERC, and proposed rate increases may be challenged by protest. If the FERC finds the rates are unjust, unreasonable or otherwise unlawful, the FERC may lower them on a prospective basis. Our rates for the interstate natural gas pipeline are derived and charged based on a cost-of-service methodology.

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.

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

The Dodd-Frank Wall Street Reform and Consumer Protection Act enacted in 2010 (the "Dodd-Frank Act") provides for new statutory and regulatory requirements for swaps and other derivative transactions, including financial and certain physical oil and gas hedging transactions. Under the Dodd-Frank Act, the Commodities Futures Trading Commission ("CFTC") has adopted regulations requiring registration of swap dealers and major swap participants, mandatory clearing of swaps, election of the end-user exception for any uncleared swaps by certain qualified companies, recordkeeping and reporting, business conduct standards and position limits among other requirements. Several of these requirements, including position limits rules, allow the CFTC to impose controls that could have an adverse impact on our ability to hedge risks associated with our business and could increase our working capital requirements to conduct these activities.

Based on an assessment of final rules promulgated by the CFTC, we have determined that we are not a swap dealer, major swap participant or a financial entity, and therefore have determined that we qualify as an end-user. The vast majority of our derivative transactions are currently transacted through a Derivatives Clearing Organization, therefore use of the end-user exception will likely not be necessary on a routine basis. We will, however, seek to retain our status as an end-user by taking reasonable measures necessary to avoid becoming a swap dealer, major swap participant or financial entity and other measures to preserve our ability to elect the end-user exception should it become necessary. Derivative transactions that are not clearable and transactions that are clearable but for which we choose to elect the end-user exception are subject to recordkeeping and reporting requirements and potentially additional credit support arrangements including cash margin or collateral. Posting of additional cash margin or collateral could affect our liquidity and reduce our ability to use cash for capital expenditures or other company purposes.

In September 2012, the U.S. District Court for the District of Columbia vacated and remanded the position limits rules adopted by the CFTC based on a necessity finding. In December 2013, the CFTC responded by proposing amended rules in an effort to better conform to the Dodd-Frank Act. Under the newly proposed rules, the CFTC would place volumetric limitations on transactions in core referenced futures contracts including NYMEX Henry Hub Natural Gas (NG), Light Sweet Crude Oil (CL), New York Harbor Gasoline Blendstock (RB) and New York Harbor Heating Oil (HO) along with any contracts which are directly or indirectly linked to the price of a core referenced futures contract. These limits include spot month limits leading up to the close of trading for a particular contract and non-spot month limits which would cover all months combined including the spot month. In the newly proposed rule, the CFTC has provided certain provisions governing Bona Fide Hedges which would enable the exclusion of certain contracts from the calculation of our positions against a given limit. While we believe that the majority of our hedging transactions would meet one or more of the enumerated categories for Bona Fide Hedges, the rules could have an adverse impact on our ability to hedge certain risks associated with our business and could potentially affect our profitability.

Risks Relating to Our Partnership Structure

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

We have significant business relationships with entities controlled by EPCO and Dan Duncan LLC. For information regarding these relationships and related party transactions with EPCO and its affiliates, see Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report. Additional information regarding our relationship with EPCO and its affiliates can be found under Part III, Item 13 of this annual report.

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

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

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have no practical ability to remove our general partner or its officers or directors. Our general partner may not be removed except upon the vote of the holders of at least 60% of our outstanding units voting together as a single class. Since affiliates of our general partner currently own approximately 36.4% of our outstanding common units, the removal of Enterprise GP as our general partner is highly unlikely without the consent of both our general partner and its affiliates. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence of a takeover premium in the trading price.

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

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

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

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

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

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

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

Unitholders may have liability to repay distributions.

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

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

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

Tax Risks to Common Unitholders

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

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to a material amount of federal taxation as an entity. The anticipated after-tax economic benefit of an investment in our common units depends, to an extent, on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service ("IRS") on this matter.

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

In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to enhance state-tax collections. If any additional state were to impose an entity-level tax upon us or our operating subsidiaries, the cash available for distribution to our unitholders would be reduced.

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

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

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

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

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

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

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

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

Tax gains or losses on the disposition of our common units could be different than expected.

If a common unitholder sells common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized in the sale and the unitholder's tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income decrease the unitholder's tax basis in the unitholder's common units, the amount, if any, of such prior excess distributions with respect to the common units a unitholder sells will, in effect, become taxable income to the unitholder if the unitholder sells such common units at a price greater than the unitholder's tax basis in those common units, even if the price received is less than the unitholder's original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to a unitholder. In addition, because the amount realized may include a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of the cash received from the sale.

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

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

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

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

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

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

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

We will be considered to have technically terminated our existing partnership and having formed a new partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which could result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if certain relief were unavailable) for one fiscal year and could result in the deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in the unitholder’s taxable income for the year of termination. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

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

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

Item 1B. *Unresolved SEC Staff Comments*.

None.

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

As part of our normal business activities, we may be named as defendants in litigation and legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. We are not aware of any material pending legal proceedings at March 3, 2014 to which we are a party, other than routine litigation incidental to our business.

On occasion, we are assessed monetary sanctions by governmental authorities related to administrative or judicial proceedings involving environmental matters. The following information summarizes such matters where the amount of monetary sanctions sought is at least $0.1 million. We do not believe that any expenditures related to the following matters will be material to our consolidated financial statements.

- § The Texas Commission on Environmental Quality ("TCEQ") notified us in the fourth quarter of 2012 that several, existing notices of enforcement issued in connection with air emissions by our Houston-area operations would be combined into one order. We believe that the eventual resolution of this consolidated order will result in monetary sanction in excess of $0.1 million.

- § In July 2013, the U.S. Environmental Protection Agency issued a Consent Agreement and Final Order in connection with certain risk management policies at our Mont Belvieu, Texas complex. We believe that the eventual resolution of these matters will result in monetary sanctions of approximately $0.4 million.

- § In September 2013, the New Mexico Environment Department issued a Notice of Violation in connection with certain administrative and monitoring matters involving our South Carlsbad Compressor Station. The eventual resolution of these matters may result in monetary sanctions of approximately $0.1 million.

- § In January 2014, we paid the State of Texas, acting through the District Attorney's Office in Travis County, Texas, a $1.2 million fine related to environmental compliance and recordkeeping matters at a tractor-trailer repair and washing facility located in Brazoria County, Texas.

For more information regarding our litigation matters, see "Litigation" under Note 17 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report, which subsection is incorporated by reference into this Item 3.

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

Not applicable.

PART II

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

Our common units are listed on the NYSE under the ticker symbol "EPD." As of January 31, 2014, there were approximately 3,000 unitholders of record of our common units. The following table presents high and low sales prices for our common units for the periods presented (as reported by the NYSE Composite ticker 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
2011					
1st Quarter	$ 44.35	$ 27.85	$ 0.5975	04/29/11	05/06/11
2nd Quarter	$ 43.95	$ 38.67	$ 0.6050	07/29/11	08/10/11
3rd Quarter	$ 43.95	$ 36.36	$ 0.6125	10/31/11	11/09/11
4th Quarter	$ 46.70	$ 38.01	$ 0.6200	01/31/12	02/09/12
2012					
1st Quarter	$ 52.95	$ 45.78	$ 0.6275	04/30/12	05/09/12
2nd Quarter	$ 52.94	$ 45.67	$ 0.6350	07/31/12	08/08/12
3rd Quarter	$ 54.98	$ 50.78	$ 0.6500	10/31/12	11/08/12
4th Quarter	$ 55.38	$ 48.52	$ 0.6600	01/31/13	02/07/13
2013					
1st Quarter	$ 60.34	$ 51.01	$ 0.6700	04/30/13	05/07/13
2nd Quarter	$ 63.56	$ 56.11	$ 0.6800	07/31/13	08/07/13
3rd Quarter	$ 65.59	$ 57.65	$ 0.6900	10/31/13	11/07/13
4th Quarter	$ 66.92	$ 59.13	$ 0.7000	01/31/14	02/07/14

Actual cash distributions are paid by us within 45 days after the end of each fiscal quarter. We expect that our cash distributions will be funded primarily through cash provided by operating activities. Although the payment of cash distributions is not guaranteed, we believe that our operations will continue to generate cash sufficient to pay distributions in the foreseeable future at levels comparable to those presented in the preceding table.

For additional information regarding our cash distributions to partners, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Recent Sales of Unregistered Securities

There were no sales of unregistered equity securities during 2013.

Common Units Authorized for Issuance Under Equity Compensation Plan

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

Issuer Purchases of Equity Securities

A total of 1,885,348 unit-based awards (e.g., restricted common unit awards granted to key employees of EPCO) vested and were converted to common units during 2013. Of this amount, 630,927 were sold back to us by employees to meet their related tax withholding requirements. The total cost of these repurchased units was approximately $36.9 million. We cancelled such treasury units immediately upon acquisition.

The following table summarizes our repurchase activity during 2013 in connection with these vesting transactions:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
February 2013 (1)	315,783	$ 55.78	--	--
May 2013 (2)	298,408	$ 60.65	--	--
August 2013 (3)	4,126	$ 61.30	--	--
November 2013 (4)	12,610	$ 63.21	--	--

(1) Of the 939,226 restricted common units that vested in February 2013 and converted to common units, 315,783 common units were sold back to us by employees to cover related tax withholding requirements.

(2) Of the 890,784 restricted common units that vested in May 2013 and converted to common units, 298,408 common units were sold back to us by employees to cover related tax withholding requirements.

(3) Of the 16,188 restricted common units that vested in August 2013 and converted to common units, 4,126 common units were sold back to us by employees to cover related tax withholding requirements.

(4) Of the 39,150 restricted common units that vested in November 2013 and converted to common units, 12,610 common units were sold back to us by employees to cover related tax withholding requirements.

Also, we announced a common unit repurchase program in December 1998 whereby we, together with certain affiliates, could repurchase up to 2,000,000 of our common units on the open market. A total of 1,381,600 common units were repurchased under this program; however, no repurchases have been made since 2002. As of December 31, 2013, we and our affiliates could repurchase up to 618,400 additional common units under this program.

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 our audited financial statements included under Part II, Item 8 of this annual report, which presents our audited balance sheets as of December 31, 2013 and 2012 and related statements of consolidated operations, comprehensive income, cash flow and equity for the three years ended December 31, 2013, 2012 and 2011, respectively. As presented in the table, amounts are in millions (except dollar per unit data).

	For the Year Ended December 31,				
	2013	2012	2011	2010	2009
Statements of operations data:					
Total revenues	$ 47,727.0	$ 42,583.1	$ 44,313.0	$ 33,739.3	$ 25,510.9
Total costs and expenses	$ 44,427.0	$ 39,538.2	$ 41,500.3	$ 31,654.1	$ 23,748.6
Equity in income of unconsolidated affiliates	$ 167.3	$ 64.3	$ 46.4	$ 62.0	$ 92.3
Operating income	$ 3,467.3	$ 3,109.2	$ 2,859.1	$ 2,147.2	$ 1,854.6
Net income	$ 2,607.1	$ 2,428.0	$ 2,088.3	$ 1,383.7	$ 1,140.3
Net income attributable to noncontrolling interests	$ 10.2	$ 8.1	$ 41.4	$ 1,062.9	$ 936.2
Net income attributable to limited partners	$ 2,596.9	$ 2,419.9	$ 2,046.9	$ 320.8	$ 204.1
Earnings per unit:					
Basic ($/unit)	$ 2.90	$ 2.81	$ 2.48	$ 1.17	$ 0.99
Diluted ($/unit)	$ 2.82	$ 2.71	$ 2.38	$ 1.15	$ 0.99
Cash distributions paid with respect to period ($/unit)	$ 2.7400	$ 2.5725	$ 2.4350	$ 2.2700	$ 2.0300

	As of December 31,				
	2013	2012	2011	2010	2009
Balance sheet data:					
Property, plant and equipment, net	$ 26,946.6	$ 24,846.4	$ 22,191.6	$ 19,332.9	$ 17,689.2
Investments in unconsolidated affiliates	$ 2,437.1	$ 1,394.6	$ 1,859.6	$ 2,293.1	$ 2,416.2
Total assets	$ 40,138.7	$ 35,934.4	$ 34,125.1	$ 31,360.8	$ 27,686.3
Long-term debt, including current maturities thereof	$ 17,351.5	$ 16,201.8	$ 14,529.4	$ 13,563.5	$ 12,427.9
Total liabilities	$ 24,698.3	$ 22,638.4	$ 21,905.8	$ 19,460.0	$ 17,213.2
Equity:					
Partners equity	$ 15,214.8	$ 13,187.7	$ 12,113.4	$ 11,374.2	$ 1,939.1
Noncontrolling interests	225.6	108.3	105.9	526.6	8,534.0
Total equity	$ 15,440.4	$ 13,296.0	$ 12,219.3	$ 11,900.8	$ 10,473.1
Limited partner units outstanding (millions)	935.7	898.8	881.6	843.7	208.8

General Discussion of Our Selected Financial Data Since 2009

In general, our results of operations have increased since 2009 as a result of increased demand for our products and services, particularly in response to increased hydrocarbon production from supply basins such as the Eagle Ford Shale in South Texas, Permian Basin in West Texas and the Rocky Mountains region. The increase in demand has supported our long-term capital spending program. As these projects are completed and commence operations, they contribute additional sources of cash flow to our operating results.

Period-to-period fluctuations in our consolidated revenues and cost of sales amounts are explained in large part by changes in energy commodity prices. Energy commodity prices fluctuate for a variety of reasons, including supply and demand imbalances and geopolitical tensions. A decrease in our consolidated marketing revenues due to lower energy commodity sales prices may not result in a decrease in operating income or cash available for distribution, since our consolidated cost of sales amounts would also be lower due to comparable decreases in the purchase prices of the underlying energy commodities. The same correlation would be true in the case of higher energy commodity sales prices and purchase costs.

Our property, plant and equipment balances have increased since 2009 as a result of our capital spending program.

Investments in unconsolidated affiliates decreased in 2011 and 2012 primarily due to the liquidation of our investment in Energy Transfer Equity, L.P. ("Energy Transfer Equity"). In general, investments in unconsolidated affiliates have increased since 2012 as a result of cash contributions we made to investees to fund their major capital projects (e.g., Texas Express Pipeline, Front Range Pipeline and the Seaway Pipeline).

Our debt balances have increased since 2009 primarily due to the funding of a portion of our capital spending program using borrowings under bank credit agreements and the issuance of senior notes. Apart from the impact of merger-related changes (such as those described in the following section), our equity balances have also increased over this period due to the funding of our capital spending program using net proceeds from the issuance of common units in connection with underwritten offerings, our distribution reinvestment plan and employee unit purchase plan programs and "at-the-market" program.

Additional information regarding our results of operations, liquidity and capital resources and capital spending can be found under Part II, Item 7 of this annual report.

Impact of Holdings Merger on 2010 and 2009 Selected Financial Data

On September 3, 2010, Enterprise GP Holdings L.P. ("Holdings"), Enterprise, Enterprise GP, Enterprise Products GP, LLC ("EPGP," the former general partner of Enterprise) and Enterprise ETE LLC ("Holdings MergerCo," a wholly owned subsidiary of Enterprise) entered into a merger agreement (the "Holdings Merger Agreement"). On November 22, 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with and into Holdings MergerCo and related transactions were completed, with Holdings MergerCo surviving such merger. Collectively, we refer to these transactions as the "Holdings Merger." As a result of completing the Holdings Merger, Enterprise GP, which had previously been the general partner of Holdings ("Holdings GP"), became Enterprise's general partner.

Prior to the merger (the "Holdings Merger"), Enterprise was a consolidated subsidiary of Holdings, which was Enterprise's parent. Upon completion of the Holdings Merger, Holdings merged with and into a wholly owned subsidiary of Enterprise. The Holdings Merger resulted in Holdings being considered the surviving consolidated entity for accounting purposes, while Enterprise was the surviving consolidated entity for legal purposes. From an accounting perspective, Holdings was deemed the acquirer of the noncontrolling interests in Enterprise that were previously recognized in Holdings' consolidated financial statements (i.e., the acquisition of Enterprise's common units and other limited partner interests that were owned by parties other than Holdings). As a result of the Holdings Merger, Enterprise's consolidated financial and operating results prior to November 22, 2010 were presented as if Enterprise was Holdings from an accounting perspective (i.e., the consolidated financial statements of Holdings became the historical financial statements of Enterprise).

Limited partner units outstanding at December 31, 2009 reflect the number of Holdings units outstanding on that date, after adjusting for the Holdings Merger exchange ratio of 1.5 Enterprise common units for each Holdings unit. At the effective time of the Holdings Merger, each issued and outstanding unit representing limited partner interests in Holdings was cancelled and converted into the right to receive Enterprise common units based on the 1.5 to 1 exchange ratio. We issued an aggregate 208,813,454 of our common units (net of fractional common units cashed out) as consideration in the Holdings Merger and, immediately after the merger, cancelled 21,563,177 of our common units previously owned by Holdings. Limited partner units outstanding at December 31, 2010 and each subsequent period include both the common units issued to third parties and affiliates since our initial public offering in 1998 and those issued in connection with the Holdings Merger.

Since Holdings regarded third party and affiliate ownership of our common units and other limited partner units as noncontrolling interests prior to the Holdings Merger, net income attributable to limited partners for 2009 and 2010 is significantly different than the amounts following the Holdings Merger. Net income attributable to limited partners following the Holdings Merger reflects all of our limited partners. Also, basic and diluted earnings per unit data for periods prior to the Holdings Merger reflect those reported by Holdings, after retroactively adjusting the amounts to reflect the 1.5 to one unit-for-unit exchange ratio.

Cash distributions per unit presented for 2009 reflect those declared and paid by Holdings. Cash distributions per unit presented for 2010 represent the sum of cash distributions declared and paid by Holdings with respect to the first, second and third quarters of 2010 and the cash distribution declared and paid by Enterprise with respect to the fourth quarter of 2010. Cash distributions per unit for 2013, 2012 and 2011 represent those declared and paid by us with respect to those years.

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

For the Years Ended December 31, 2013, 2012 and 2011

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

Key References Used in this Management's Discussion and Analysis

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

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

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

In addition to owning our general partner, affiliates of privately held EPCO owned approximately 36.4% of our limited partner interests at December 31, 2013.

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

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

Cautionary Statement Regarding Forward-Looking Information

This annual report on Form 10-K for the year ended December 31, 2013 (our "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," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations are intended to identify forward-looking statements. Although we and our general partner believe that our expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions as described in more detail under Part I, Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or *expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this annual report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.*

Overview of Business

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO and are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, petrochemicals and refined products.

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States ("U.S."), Canada and Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals (including liquefied petroleum gas or "LPG"); crude oil gathering, transportation, storage and terminals; offshore production platforms; petrochemical and refined products transportation and services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. Our assets include approximately 51,000 miles of onshore and offshore pipelines; 200 MMBbls of storage capacity for NGLs, petrochemicals, refined products and crude oil; and 14 Bcf of natural gas storage capacity. In addition, our asset portfolio includes 24 natural gas processing plants, 22 NGL and propylene fractionators, six offshore hub platforms located in the Gulf of Mexico, a butane isomerization complex, NGL import and LPG export terminals, and octane enhancement and high-purity isobutylene production facilities.

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

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. For information regarding our business segments, see Note 13 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Significant Recent Developments

Front Range Pipeline Begins Operations

Our Front Range Pipeline commenced operations in February 2014. This 435-mile pipeline transports NGLs originating from the Denver-Julesburg production basin in Weld County, Colorado to Skellytown, Texas in Carson County. With connections to our Mid-America Pipeline System and Texas Express Pipeline, the Front Range Pipeline provides producers in the Denver-Julesburg basin with access to the Gulf Coast, which is the largest NGL market in the U.S. Initial throughput capacity for the Front Range Pipeline is 150 MBPD, which could be expanded to approximately 230 MBPD with certain system modifications. The Front Range Pipeline is owned by Front Range Pipeline LLC, which is a joint venture among us and affiliates of DCP Midstream Partners LP ("DCP") and Anadarko Petroleum Corporation ("Anadarko"). We operate the Front Range Pipeline and own a one-third member interest in Front Range Pipeline LLC.

Appalachia-to-Texas Express ("ATEX Express") Pipeline Begins Operations

Our ATEX Express pipeline commenced operations in January 2014. The ATEX Pipeline transports ethane in southbound service from NGL fractionation plants located in Pennsylvania, West Virginia and Ohio to our Mont Belvieu storage complex. The ethane extracted by these fractionation facilities originates from the Marcellus and Utica Shale production areas. In addition to newly constructed pipeline segments, significant portions of the ATEX Express pipeline consist of segments that were formerly used in refined products transportation service by our TE Products Pipeline. Initial throughput capacity for the ATEX Express pipeline is 125 MBPD, which could be expanded to approximately 265 MBPD with certain system modifications.

ATEX Express terminates at our Mont Belvieu storage complex, which includes approximately 110 MMBbls of NGL and petroleum liquid storage capacity and an extensive pipeline distribution system. With the addition of our Aegis Pipeline (currently under construction), we will link Marcellus and Utica Shale-produced ethane to existing ethylene production facilities along the U.S. Gulf Coast and provide supply security to support construction of new third-party ethylene plants currently planned at Texas and Louisiana petrochemical facilities. Also, since our distribution system supports our LPG export terminal on the Houston Ship Channel, ethane volumes delivered to Mont Belvieu via ATEX may enhance the prospects for U.S.-produced ethane being exported to international markets.

Expansion of Houston Ship Channel LPG Export Terminal

We provide customers with LPG export services at our marine terminal located on the Houston Ship Channel. This terminal has the capability to load cargoes of fully refrigerated, low-ethane propane and/or butane onto multiple tanker vessels simultaneously. In March 2013, we completed an expansion project at this terminal that increased its loading capability from 4.0 MMBbls per month to 7.5 MMBbls per month. Our LPG export services continue to benefit from increased NGL supplies produced from domestic shale plays such as the Eagle Ford Shale and strong international demand for propane as a feedstock in ethylene plant operations and for power generation and heating purposes.

In September 2013, we announced an expansion project at this LPG export terminal that is expected to increase its ability to load cargoes from 7.5 MMBbls per month to approximately 9.0 MMBbls per month. This expansion project is expected to be completed in the first quarter of 2015.

In January 2014, we announced a further expansion of this LPG export terminal that is expected to increase its ability to load cargoes from approximately 9.0 MMBbls per month to in excess of 16.0 MMBbls per month. Once this expansion project is completed, we expect our maximum loading capacity at this export terminal will be approximately 27,000 barrels per hour. This expansion project is supported by a 50-year service agreement with Oiltanking Partners, L.P. ("Oiltanking"), which has agreed to provide additional dock space and related services to us at the terminal site. The expanded LPG export terminal is expected to be in service by the end of 2015 and is supported by long-term LPG export agreements.

Mid-America Pipeline System's Rocky Mountain Expansion Project Begins Operations

In January 2014, we announced the completion of an expansion project involving the Rocky Mountain pipeline of our Mid-America Pipeline System. This expansion project involved looping 265 miles of the Rocky Mountain pipeline, as well as related pump station modifications, which increased transportation capacity on the pipeline from approximately 275 MBPD to 350 MBPD (after taking into account shipper commitments to the expansion project). This expansion project was built to accommodate growing natural gas and NGL production from major supply basins in Colorado, New Mexico, Utah and Wyoming.

Start-Up of Eighth NGL Fractionator at Our Mont Belvieu Complex

In November 2013, we announced that the eighth NGL fractionator at our Mont Belvieu complex was placed in service. This new unit, which has the capacity to fractionate up to 85 MBPD of NGLs, increases total NGL fractionation capacity at our Mont Belvieu complex to approximately 670 MBPD. This fractionator, along with a seventh unit placed into service in September 2013, was built to handle increasing NGL production from domestic shale plays, including the Eagle Ford Shale in South Texas and other supply basins in the Rocky Mountains and Mid-Continent regions.

Our seventh and eighth NGL fractionators are owned by a joint venture, formed in June 2013, between us and Western Gas Partners, LP ("Western Gas"), which is an affiliate of Anadarko. We own 75% of the joint venture's member interests, with Western Gas owning a 25% noncontrolling interest in the joint venture.

Texas Express Pipeline and Related Gathering Systems Begin Operations

Our Texas Express Pipeline and two related NGL gathering systems commenced operations in November 2013. The Texas Express Pipeline originates in Skellytown, Texas and extends approximately 580 miles to Mont Belvieu, Texas. The Texas Express Pipeline gives producers in West and Central Texas, the Rocky Mountains, southern Oklahoma, the Mid-Continent and the Denver-Julesburg supply basin much needed takeaway capacity for growing NGL production volumes and improved access to Mont Belvieu, which is the primary industry hub for domestic NGL production. The Texas Express Pipeline is owned by Texas Express Pipeline LLC, which is a joint venture among us and affiliates of Enbridge Energy Partners, L.P. ("Enbridge"), Anadarko and DCP. We operate the Texas Express Pipeline and own a 35% member interest in Texas Express Pipeline LLC.

Mixed NGL volumes from the Rocky Mountains, Permian Basin and Mid-Continent regions are transported to the Texas Express Pipeline using our Mid-America Pipeline System. NGL volumes from the Denver-Julesburg supply basin are transported to the Texas Express Pipeline using the Front Range Pipeline. Initial throughput capacity for the Texas Express Pipeline is 280 MBPD, which could be expanded to approximately 400 MBPD with certain system modifications.

In addition to the start of operations on the Texas Express Pipeline, service also commenced on two mixed NGL gathering systems developed by Texas Express Gathering LLC, which is a second joint venture among Enbridge, Anadarko and us. We own a 45% member interest in Texas Express Gathering LLC. Enbridge serves as operator of the two gathering systems, which link natural gas processing plants in the Anadarko/Granite Wash and Central Texas/Barnett Shale production areas to the Texas Express Pipeline.

Expansion of Eagle Ford Crude Oil Pipeline System

In September 2013, we, along with Plains All American Pipeline, L.P. ("Plains"), announced an expansion of our Eagle Ford Crude Oil Pipeline System in South Texas. The expansion is expected to increase the pipeline system's capacity to transport light and medium grades of crude oil from 300 MBPD to 470 MBPD in order to accommodate expected volumes from Plains' Cactus pipeline. As currently planned, the expansion of our Eagle Ford Crude Oil Pipeline System would be completed in stages that include adding pumping capacity and looping certain segments of the existing system. The expansion also includes constructing an additional 2.3 MMBbls of operational storage capacity at Gardendale, Tilden and Corpus Christi, Texas. We expect the expansion to be completed during the second quarter of 2015.

Plans to Develop Refined Products Export Facilities on Texas Gulf Coast

In May 2013, we announced the development of a refined products export facility in Beaumont, Texas to meet growing demand for additional refined products export capability on the U.S. Gulf Coast. Export service at this marine terminal is expected to begin during the first quarter of 2014 and would accommodate Panamax class vessels. Panamax class vessels are medium-sized tanker ships designed to transit the existing lock chambers of the Panama Canal. This new export facility will complement our existing refined products pipelines, storage and terminal facilities in southeast Texas and enable us to provide customers with improved access to international markets. In addition to the planned Beaumont export facility, we are evaluating the potential for a second refined products export facility on the Houston Ship Channel.

Plans to Expand Crude Oil Storage and Distribution Infrastructure Serving Southeast Texas

Historically, southeast Texas refineries have been supplied primarily by waterborne imports of crude oil. With the increase in North American production, crude oil from the Eagle Ford, Permian, Mid-Continent, Bakken and Canada are flowing into Southeast Texas and displacing waterborne crude oil imports. Due to growing domestic production, we expect a significant increase in North American crude oil deliveries to the Gulf Coast market, which currently lacks sufficient storage capacity and has an inadequate distribution system for handling these varying grades of domestic crude oil.

In response, we announced plans in May 2013 to significantly expand our crude oil storage and distribution infrastructure serving the southeast Texas refinery market. This planned expansion involves the construction of approximately 4.4 MMBbls of combined new crude oil storage capacity at our Enterprise Crude Houston ("ECHO") storage facility that will increase this facility's capacity to approximately 6.5 MMBbls. Also, we plan to construct 55 miles of associated pipelines to directly connect the ECHO storage facility with several major refineries in the Southeast Texas market. The expansion would be completed in phases with final completion expected in the second quarter of 2015.

Upon completion of these projects, we will be able to provide southeast Texas refiners with an integrated system featuring supply diversification, significant storage capabilities and a high capacity pipeline distribution system that will be directly connected to refineries having an aggregate capacity of approximately 3.6 MMBPD. In addition, the ECHO storage facility will have access to our marine NGL and crude oil terminal at Morgan's Point on the Houston Ship Channel.

Plans to Build Gulf Coast Ethane Pipeline

In March 2013, we announced the receipt of transportation commitments to support development of our 270-mile Aegis Ethane Pipeline, which will deliver ethane to petrochemical plants in the U.S. Gulf Coast region. The Aegis Ethane Pipeline will originate at our Mont Belvieu, Texas storage complex and have the capacity to transport up to 425 MBPD of purity ethane volumes to various petrochemical customers along the Gulf Coast of Texas and Louisiana. The Aegis Ethane Pipeline is expected to commence operations in stages, with initial sections starting service in the third quarter of 2014 and the remaining sections at different times through the second quarter of 2015.

General Outlook for 2014

Commercial Outlook

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

As a result of significant advances in non-conventional drilling and production technology, North American reserves and production of hydrocarbons from shale developments have increased substantially. The rapid increase in U.S. hydrocarbon supplies has led to a reduction in imports of crude oil, NGLs, refined products and natural gas. Conversely, this same trend has resulted in significant increases in hydrocarbon exports, particularly of refined products and propane, and contributed to volatility in the price of natural gas and ethane. In general, a lack of infrastructure to export natural gas and ethane has contributed to an oversupply of these energy commodities in recent years.

With respect to natural gas, it has been trading at a significant discount to crude oil due to changes in supply and demand fundamentals. For example, on an energy equivalent basis, natural gas prices for 2014 are forecast to be approximately 25% to 30% of the price of crude oil (based on prices quoted in futures markets in January 2014). For 2013 and 2012, natural gas was priced at 22% and 18% of crude oil on an energy equivalent basis, respectively. In addition, ethane prices have decreased over time in terms of price per gallon and as a percentage relative to the price of crude oil on an energy equivalent basis. The decline in ethane prices is attributable to excess domestic inventories of this commodity. For example, the average price of ethane in 2011 was $0.77 per gallon (or 16% of the relative price of crude oil on an energy equivalent basis). The average price of ethane continued to decline in 2012, decreasing to $0.40 per gallon (or 9% of the relative price of crude oil) and further to $0.26 per gallon (or 5% of the relative price of crude oil) in 2013.

As a result of these price trends, producers continue to decrease their drilling activity in onshore areas where natural gas production is considered "dry" or "lean" (i.e., the amount of NGLs produced in connection with the natural gas production is relatively small) and focus more on NGL-rich natural gas and crude oil developments. A similar trend is also occurring in the Gulf of Mexico, with producers investing capital to develop new sources of crude oil production rather than areas where natural gas production is prevalent.

In conjunction with these price trends, in recent years natural gas and NGLs have developed a significant feedstock price advantage over more costly crude oil derivatives (such as naphtha), and this trend is expected to continue based on prices quoted on the futures markets in January 2014. This trend is supported by several factors including: (i) technological breakthroughs in drilling techniques used by exploration and production companies in connection with domestic shale resource plays, which have significantly increased U.S. crude oil, natural gas and NGL resources and lowered associated finding and development costs; (ii) the growing demand for crude oil by China, India and other developing economies; (iii) geopolitical risks in many areas of the world that are major exporters of crude oil such as the Middle East; and (iv) the general inability to export natural gas from the U.S. resulting in an oversupply of and lower market values for natural gas. New natural gas export facilities face various hurdles to their construction, including significant capital requirements, long construction timeframes, and permitting and regulatory issues.

As a result of the feedstock price advantage currently held by natural gas and NGLs, energy consumers in the industrial manufacturing and power generation sectors are continuing to adjust their feedstock and asset portfolios to consume increasing amounts of natural gas and NGLs in their operations. In addition, we believe the feedstock price advantage of domestically-produced NGLs has led to a long-term fundamental change in feedstock selection by the U.S. petrochemical industry, which is the largest consumer of domestic NGLs. Since NGLs typically trade at a significant discount to crude oil, using NGLs as a feedstock provides a substantial cost advantage for U.S. petrochemical companies when compared to naphtha, whose price is closely linked to international crude prices. From 2009 through 2013, ethane and propane have consistently been the most profitable feedstocks in the production of ethylene. In order to capitalize on this cost advantage, U.S. petrochemical companies have maximized their consumption of domestic NGLs, particularly ethane, in the production of ethylene. Many of these companies have announced plans to invest billions of dollars to construct NGL feedstock-oriented, world-scale ethylene plants on the Gulf Coast. For example, CP Chemical announced in December 2011 that it expects to build a 1.5 million metric tons per year ethylene plant in Cedar Bayou, Texas by 2017. Likewise, Formosa Plastics announced in March 2012 that it expects to build an 800 thousand metric tons per year ethylene plant along the U.S. Gulf Coast by 2016/2017. Also, Dow Chemical announced in April 2012 that it expects to build a 1.5 million metric tons per year ethylene plant along the U.S. Gulf Coast by 2017. Almost all of these new plants and the ethylene industry's major expansions are in close proximity to our existing or planned assets.

Based on industry publications, domestic production of ethylene in 2013 was estimated to be 147 million pounds per day compared to 144 million pounds per day in 2012.   Ethane is the most widely used feedstock by the U.S. petrochemical industry in the production of ethylene. As a result, ethane consumption by domestic petrochemical companies has, at times, been in excess of 1.0 million BPD. We believe the U.S. ethylene industry could consume approximately 250 MBPD of additional ethane feedstocks over the next three years through modifications, debottlenecking and expansions at existing facilities. In addition, we believe that announced new petrochemical plant construction projects, including those noted in the preceding paragraph, could consume between 600 MBPD and 750 MBPD of additional ethane feedstocks when completed. However, in the near term and in the absence of such major plant construction and expansion projects being completed, we expect that ethane production will increase more rapidly than the ethylene industry's current capability to consume the increase in supplies (resulting in an oversupply of ethane). The current ethane oversupply situation may result in volatile ethane prices and prolonged periods of ethane rejection by producers and natural gas processors in an effort to balance supply and demand. This could lower the value of our equity NGL production and reduce the volumes that would otherwise be handled by our NGL fractionators and pipelines.

U.S. LPG exports (propane and butane) continue to increase as a result of ample supplies and competitive prices. Overall, U.S. propane waterborne exports increased from approximately 153 MBPD in 2012 to 288 MBPD in 2013. Markets in Central and South America have been the major source of new demand for U.S. LPG exports; however, volumes are also being transported to Northwest Europe and Far East Asia. LPG exports from the U.S. Gulf Coast to Central and South America are expected to increase in the future due to ample propane and butane supplies, competitive pricing and lower transport costs to these markets. Similarly, greater volumes of Gulf Coast-sourced LPGs are expected to reach Asian markets after the anticipated Panama Canal expansion is completed (currently forecast between 2015 and 2018). This expansion project is expected to make LPG exports from the Gulf Coast to Asia more economical for shippers. In 2013, U.S. ethane exports were generally limited to petrochemical customers in Canada that could receive volumes by pipeline; however, as a result of the continuing abundant supply situation for ethane and its cost advantage relative to other feedstocks, we continue to receive interest from petrochemical companies outside of North America regarding potential long-term ethane export arrangements using marine facilities on the Gulf Coast.

Drilling activity forecast for 2014 is expected to remain robust in shale plays containing crude oil, condensate and NGL-rich natural gas production such as the Eagle Ford, Bakken, Niobrara, Mississippian, Wolfcamp, Woodford, Marcellus and Utica shales. In the Eagle Ford Shale, which runs parallel to the Texas Gulf Coast, we have completed several expansion projects that enable us to gather, transport and process in excess of 1.0 Bcf/d of new NGL-rich natural gas production and to transport substantial volumes of crude oil and condensate to market. In general, energy companies are continuing to have significant success in the Eagle Ford and have accelerated their associated drilling programs. Production from this region includes crude oil, condensate, NGL-rich natural gas and dry natural gas. Since 2010, we have announced major expansions of our natural gas pipeline, storage and processing facilities; NGL pipeline and fractionation facilities; and crude oil pipeline and storage facilities to accommodate the production growth from this region. In the aggregate, these projects account for approximately $4.0 billion of our capital expenditures from 2010 through 2013.

Drilling activity in shale plays with predominantly dry natural gas reserves or natural gas reserves with a lower NGL content (e.g., the Haynesville/Bossier, Barnett, Fayetteville, Piceance and Jonah/Pinedale shales) are expected to remain well below peak levels. As a result, we expect that natural gas volumes on pipelines that serve these supply basins, including our Jonah, Piceance Basin, San Juan and Haynesville gathering systems, may decline further in 2014 when compared to 2013. Although these supply basins are currently experiencing production declines, we believe that these areas have substantial, undeveloped natural gas reserves with some of the lowest exploration and production costs in the U.S. Furthermore, we believe that as U.S. demand for natural gas and ethane becomes more balanced and, as a result, natural gas and ethane prices stabilize and increase, these supply basins could experience an increase in drilling activity to support, and potentially increase, their future production levels.

With respect to the Gulf of Mexico, producers continue to increase drilling activity following federal regulatory uncertainty in the aftermath of the Deepwater Horizon (or Macondo) incident. We expect that transportation volumes on our offshore crude oil pipelines will continue to increase as significant deepwater prospects begin production. For example, we expect that our Southeast Keathley Canyon Pipeline (the “SEKCO pipeline”) will commence operations during the third quarter of 2014. The 149-mile SEKCO crude oil gathering pipeline, which is expected to have a capacity of 115 MBPD, will serve the new Lucius crude oil and natural gas field located in the southern Keathley Canyon area of the deepwater central Gulf of Mexico. Conversely, we expect that throughput volumes on our offshore Gulf of Mexico natural gas pipelines will continue to decline in 2014 due to producers focusing more of their near-term resources to exploit offshore crude oil developments and onshore NGL-rich natural gas and crude oil producing areas. However, we believe that as U.S. natural gas supply and demand becomes more balanced and, as a result, natural gas prices stabilize and increase, natural gas production from the Gulf of Mexico could experience an increase in drilling activity.

Our TE Products Pipeline and related Centennial Pipeline are designed to transport refined products from refineries on the Gulf Coast to markets in the Midwest and Northeast U.S. As a result of increased refinery production in the Midwest and lower demand for refined products in these markets, demand to transport refined products from the Gulf Coast has decreased. In order to efficiently utilize our refined products pipelines, management is pursuing projects that convert portions of these pipelines and related infrastructure to alternate uses. For example, certain segments of our TE Products Pipeline were repurposed to accommodate the southbound transportation of ethane from the Marcellus and Utica Shales by our ATEX Express pipeline, which commenced operations in January 2014. Another example would be the conversion of our Gulf Coast refined products import facility into a refined products export dock. We anticipate that the first phase of our refined products export dock will be placed into service during the second quarter of 2014.

As a result of our crude oil pipeline infrastructure improvements, we have greater access to U.S. Gulf Coast refiners. Historically, these refining customers have purchased crude oil based on Light Louisiana Sweet ("LLS") prices, which averaged $107.34 per barrel for 2013 compared to $111.72 per barrel for 2012. Whereas WTI prices have generally been reflective of the economics of the Mid-Continent crude oil market, LLS prices are reflective of market economics along the Gulf Coast for light sweet grades of crude oil, whether foreign or domestic, although certain Gulf Coast markets such as Houston trade at a discount to LLS.

Price differentials between West Texas Intermediate ("WTI") and Brent crude oil narrowed appreciably in 2013 compared to 2012, with the spread averaging $10.79 per barrel in 2013 compared to $17.50 per barrel in 2012. Furthermore, with additional pipeline capacity between the Mid-Continent and the Gulf Coast being placed into service, along with growing pipeline capacity to redirect Permian Basin crude oil production directly to the Gulf Coast, the price differential between WTI and LLS crude oil also narrowed appreciably to average $9.37 per barrel in 2013 compared to $17.52 per barrel in 2012. Similarly, with growth in the ability to route crude oil to the U.S. Gulf Coast, the LLS to Brent differential fell appreciably in 2013, dropping from an average of a positive $1.28 per barrel in the first half 2013 to a negative $4.12 per barrel in the second half of 2013. Cheaper LLS prices compared to Brent encourage domestic crude oil barrels to move from the Mid-Continent to the Gulf Coast and discourage crude oil imports; and refiners in the Mid-Continent and Gulf Coast benefit from more attractive domestic crude prices compared to higher priced waterborne crudes like Brent. As a result, many domestic refineries are modifying and expanding their facilities in order to process more North American crude oil and are also increasing their refined product exports in order to capture market share in emerging economies, which typically have insufficient refining capacity to satisfy their growing demand. We expect North American crude oil supplies to continue to displace imported crude oil volumes, particularly light, sweet grades, in 2014 and we expect the U.S. refining industry to continue to capitalize on the growing availability of competitively priced, domestic crudes, including increasing their exports of refined products.

In conclusion, we expect that natural gas production from NGL-rich shale and other non-conventional developments will, despite periods of ethane rejection, support the utilization of our NGL pipeline, storage and fractionation assets and certain of our natural gas pipelines and processing plants in 2014. We also expect that our distribution pipelines, export facilities and marketing activities will benefit in 2014 due to increased demand for purity NGL products and exports of LPGs and refined products. With approximately $5.5 billion of major organic growth projects currently under construction, we believe we are well positioned for future growth through 2015. Our partnership's large geographic asset footprint, including significant access to growing energy intensive industries, especially along the Gulf Coast, and growing demand for exports continues to provide us with significant growth opportunities on both the supply and demand side of the value chain.

Liquidity Outlook

At December 31, 2013, we had approximately $4.1 billion of consolidated liquidity, which is defined as unrestricted cash on hand plus borrowing capacity available under our aggregate $4.5 billion of bank credit facilities. Throughout 2013, the corporate debt and equity capital markets were accessible to us, along with adequate credit availability from banks. Based on current market conditions, we believe we will have sufficient liquidity, cash flow from operations and access to capital markets to fund our capital expenditures and working capital requirements in 2014.

Affiliates of privately held EPCO purchased $100.0 million of our common units during 2013 through our distribution reinvestment plan ("DRIP"). These same EPCO affiliates have expressed a willingness to purchase up to $100 million of our common units again in 2014 through our DRIP. Their first $25.0 million reinvestment was made in February 2014 and resulted in the issuance of 403,315 of our common units.

In January 2014, $500.0 million in principal amount of Senior Notes O matured and were repaid using the issuance of short-term notes under EPO's commercial paper program. In February 2014, EPO issued $850 million in principal amount of 3.90% senior notes due February 2024 ("Senior Notes JJ") and $1.15 billion in principal amount of 5.10% senior notes due February 2045 ("Senior Notes KK"). Net proceeds of $1.98 billion from the issuance of Senior Notes JJ and KK were used to repay debt, including amounts then outstanding under EPO's $3.5 Billion Multi-Year Revolving Credit Facility and EPO's commercial paper program (which we used to repay $500.0 million in principal amount of Senior Notes O that matured in January 2014) and for general company purposes.

As of March 3, 2014, we had approximately $2.7 billion of senior notes maturing in the October 2014 through December 2016 timeframe. The U.S. government is expected to continue to run substantial annual budget deficits from 2014 through 2016 that will require a corresponding issuance of debt by the U.S. Treasury. 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 impact the expected large issuances of U.S. Treasury debt and the prevailing economic and capital market conditions during these future periods will have on the cost and availability of capital, and we have not executed any interest rate swaps to hedge a portion of our expected future debt issuances in connection with the refinancing of debt. We continue to monitor and evaluate the condition of the capital markets and our interest rate risk with respect to refinancing these maturities and funding our capital spending program.

Total capital spending for 2013 was $4.5 billion, which included $292 million of sustaining capital expenditures. Our most significant growth capital expenditures for the year ended December 31, 2013 involved projects in the Eagle Ford Shale, at our Mont Belvieu complex, to expand joint venture crude oil pipelines and for the ATEX Express pipeline. We currently expect total capital spending for 2014 to be in the range of $3.9 billion to $4.4 billion, which includes $350 million for sustaining capital expenditures.

Results of Operations

Summarized Consolidated Income Statement Data

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

	For the Year Ended December 31,		
	2013	**2012**	**2011**
Revenues	$ 47,727.0	$ 42,583.1	$ 44,313.0
Costs and expenses:			
Operating costs and expenses:			
Cost of sales	40,770.2	36,015.5	38,292.6
Other operating costs and expenses	2,310.4	2,244.9	2,195.4
Depreciation, amortization and accretion expenses	1,148.9	1,061.7	958.7
Gains attributable to asset sales and insurance recoveries	(83.4)	(17.6)	(156.0)
Non-cash asset impairment charges	92.6	63.4	27.8
Total operating costs and expenses	44,238.7	39,367.9	41,318.5
General and administrative costs	188.3	170.3	181.8
Total costs and expenses	44,427.0	39,538.2	41,500.3
Equity in income of unconsolidated affiliates	167.3	64.3	46.4
Operating income	3,467.3	3,109.2	2,859.1
Interest expense	(802.5)	(771.8)	(744.1)
Other, net	(0.2)	73.4	0.5
Benefit from (provision for) income taxes	(57.5)	17.2	(27.2)
Net income	2,607.1	2,428.0	2,088.3
Net income attributable to noncontrolling interests	(10.2)	(8.1)	(41.4)
Net income attributable to limited partners	$ 2,596.9	$ 2,419.9	$ 2,046.9

Consolidated Revenues

The following table presents each business segment's contribution to revenues (net of eliminations) for the years indicated (dollars in millions):

	For the Year Ended December 31,		
	2013	2012	2011
NGL Pipelines & Services:			
Sales of NGLs and related products	$ 15,916.0	$ 14,218.5	$ 16,724.6
Midstream services	1,204.2	949.9	758.7
Total	17,120.2	15,168.4	17,483.3
Onshore Natural Gas Pipelines & Services:			
Sales of natural gas	2,571.6	2,395.4	2,866.5
Midstream services	966.9	957.2	863.7
Total	3,538.5	3,352.6	3,730.2
Onshore Crude Oil Pipelines & Services:			
Sales of crude oil	20,371.3	17,548.7	15,962.6
Midstream services	279.1	113.0	98.5
Total	20,650.4	17,661.7	16,061.1
Offshore Pipelines & Services:			
Sales of natural gas	0.5	0.4	1.1
Sales of crude oil	5.7	3.3	9.4
Midstream services	153.2	187.8	245.5
Total	159.4	191.5	256.0
Petrochemical & Refined Products Services:			
Sales of petrochemicals and refined products	5,568.8	5,470.9	6,000.6
Midstream services	689.7	738.0	781.8
Total	6,258.5	6,208.9	6,782.4
Total consolidated revenues	$ 47,727.0	$ 42,583.1	$ 44,313.0

Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base. Our largest non-affiliated customer for 2013 was BP p.l.c. and its affiliates ("BP"), which accounted for $4.31 billion, or 9.0%, of our consolidated revenues for the year. The following table presents our consolidated revenues from BP by business segment for the year ended December 31, 2013 (dollars in millions):

NGL Pipelines & Services	$ 1,137.6
Onshore Natural Gas Pipelines & Services	164.3
Onshore Crude Oil Pipelines & Services	2,833.1
Petrochemical & Refined Products Services	176.7
Total consolidated revenues from BP	$ 4,311.7

BP was also our largest non-affiliated customer for 2012, accounting for 9.5% of our consolidated revenues for the year ended December 31, 2012. Shell Oil Company and its affiliates was our largest non-affiliated customer in 2011, accounting for 10.6% of our consolidated revenues for the year ended December 31, 2011.

Selected Energy Commodity Price Data

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

	Natural Gas, $/MMBtu (1)	Ethane, $/gallon (2)	Propane, $/gallon (2)	Normal Butane, $/gallon (2)	Isobutane, $/gallon (2)	Natural Gasoline, $/gallon (2)	Polymer Grade Propylene, $/pound (3)	Refinery Grade Propylene, $/pound (3)	WTI Crude Oil, $/barrel (4)	LLS Crude Oil, $/barrel (4)
2011 Averages	$ 4.04	$ 0.77	$ 1.46	$ 1.85	$ 2.06	$ 2.34	$ 0.76	$ 0.64	$ 95.12	$ 112.28
2012 by quarter:										
1st Quarter	$ 2.72	$ 0.56	$ 1.26	$ 1.93	$ 2.04	$ 2.39	$ 0.69	$ 0.60	$ 102.93	$ 119.59
2nd Quarter	$ 2.21	$ 0.40	$ 0.98	$ 1.62	$ 1.75	$ 2.05	$ 0.66	$ 0.51	$ 93.49	$ 108.47
3rd Quarter	$ 2.80	$ 0.34	$ 0.89	$ 1.44	$ 1.62	$ 2.01	$ 0.51	$ 0.37	$ 92.22	$ 109.40
4th Quarter	$ 3.41	$ 0.28	$ 0.88	$ 1.64	$ 1.82	$ 2.15	$ 0.56	$ 0.48	$ 88.18	$ 109.43
2012 Averages	$ 2.79	$ 0.40	$ 1.00	$ 1.65	$ 1.81	$ 2.15	$ 0.60	$ 0.49	$ 94.20	$ 111.72
2013 by quarter:										
1st Quarter	$ 3.34	$ 0.26	$ 0.86	$ 1.58	$ 1.65	$ 2.23	$ 0.75	$ 0.65	$ 94.37	$ 113.93
2nd Quarter	$ 4.10	$ 0.27	$ 0.91	$ 1.24	$ 1.27	$ 2.04	$ 0.63	$ 0.53	$ 94.22	$ 104.63
3rd Quarter	$ 3.58	$ 0.25	$ 1.03	$ 1.33	$ 1.35	$ 2.15	$ 0.68	$ 0.58	$ 105.82	$ 109.89
4th Quarter	$ 3.60	$ 0.26	$ 1.20	$ 1.43	$ 1.45	$ 2.10	$ 0.68	$ 0.56	$ 97.46	$ 100.94
2013 Averages	$ 3.65	$ 0.26	$ 1.00	$ 1.39	$ 1.43	$ 2.13	$ 0.69	$ 0.58	$ 97.97	$ 107.34

(1) Natural gas prices are based on Henry-Hub Inside FERC commercial index prices as reported by Platts, which is a division of McGraw Hill Financial, Inc.
(2) NGL prices for ethane, propane, normal butane, isobutane and natural gasoline are based on Mont Belvieu Non-TET commercial index prices as reported by Oil Price Information Service.
(3) Polymer grade propylene prices represent average contract pricing for such product as reported by Chemical Market Associates, Inc. ("CMAI"). Refinery grade propylene prices represent weighted-average spot prices for such product as reported by CMAI.
(4) Crude oil prices are based on commercial index prices for WTI as measured on the New York Mercantile Exchange ("NYMEX") and for LLS as reported by Platts.

Period-to-period fluctuations in our consolidated revenues and cost of sales amounts are explained in large part by changes in energy commodity prices. Energy commodity prices fluctuate for a variety of reasons, including supply and demand imbalances and geopolitical tensions. The following is a discussion of changes in key commodity prices affecting our results of operations during the year ended December 31, 2013:

§ The weighted-average indicative market price for NGLs (based on prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production) was $1.02 per gallon for 2013 compared to $1.12 per gallon for 2012 – a 10% year-to-year decrease. Ethane accounts for the largest volume of NGLs extracted from the natural gas stream. The price of ethane averaged $0.26 per gallon during 2013 compared to $0.40 per gallon during 2012. According to U.S. Energy Information Administration statistics, ethane volumes account for approximately 35% of NGLs produced from natural gas processing activities. As a result of producers allocating more of their capital budgets to developing NGL-rich shale plays and their success in extracting such resources, ethane production has increased more rapidly than the ethylene industry's current capability to consume the increase in supplies. This oversupply situation has contributed to a significant decrease in average ethane prices since the fourth quarter of 2011.

§ The market price of natural gas (as measured at the Henry Hub in Louisiana) averaged $3.65 per MMBtu for 2013 compared to $2.79 per MMBtu during 2012 – a 31% year-to-year increase. The increase in prices is generally due to higher natural gas demand for power generation and as a heating fuel.

§ The market price of WTI crude oil (as measured on the NYMEX) averaged $97.97 per barrel for 2013 compared to $94.20 per barrel for 2012. A significant factor in the increase in WTI crude oil prices has been the completion of midstream infrastructure projects, such as the reversal of our Seaway pipeline in mid-2012, which allowed crude oil production formerly stranded at the Cushing hub to reach refining markets along the Gulf Coast.

A decrease in our consolidated marketing revenues due to lower energy commodity sales prices may not result in a decrease in gross operating margin or cash available for distribution, since our consolidated cost of sales amounts would also be lower due to comparable decreases in the purchase prices of the underlying energy commodities. The same correlation would be true in the case of higher energy commodity sales prices and purchase costs.

We attempt to mitigate any commodity price exposure through our hedging activities as well as through converting keepwhole and similar contracts to fee-based arrangements. See Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for information regarding our commodity hedging activities.

Consolidated Income Statement Highlights

The following information highlights significant changes in our comparative income statement amounts and the primary drivers of such changes.

Comparison of 2013 with 2012. Revenues for 2013 increased $5.14 billion when compared to 2012. Revenues from the marketing of crude oil increased $2.83 billion year-to-year primarily due to higher sales volumes, which accounted for a $2.28 billion increase, and sales prices, which accounted for an additional $543.8 million increase. Revenues from the marketing of NGLs increased a net $1.7 billion year-to-year primarily due to higher sales volumes, which accounted for a $3.64 billion increase, partially offset by lower sales prices, which accounted for a $1.94 billion decrease. Revenues from the marketing of natural gas and petrochemical products increased a net $392.4 million year-to-year primarily due to higher sales prices, which accounted for a $1.1 billion increase, partially offset by lower sales volumes, which accounted for a $708.3 million decrease. Revenues from the marketing of refined products decreased a net $106.8 million year-to-year primarily due to lower sales prices, which accounted for a $697.7 million decrease, which was partially offset by the impact of higher sales volumes, which accounted for a $590.9 million increase. Revenues from midstream asset services increased $347.2 million year-to-year primarily due to contributions from recently completed assets that have started operations in the Eagle Ford Shale and at our Mont Belvieu complex.

Total operating costs and expenses for 2013 increased $4.87 billion when compared to 2012 primarily due to a $4.75 billion increase in cost of sales. The cost of sales associated with our marketing of crude oil increased $2.59 billion year-to-year primarily due to higher sales volumes, which accounted for a $2.15 billion increase, and purchase prices, which accounted for an additional $440.1 million increase. Cost of sales associated with the marketing of NGLs increased a net $1.95 billion year-to-year primarily due to higher sales volumes, which accounted for a $3.36 billion increase, partially offset by lower purchase prices, which accounted for a $1.41 billion decrease. Cost of sales associated with our marketing of natural gas and petrochemical products increased a net $377.2 million year-to-year primarily due to higher purchase prices, which accounted for a $1.02 billion increase, partially offset by lower sales volumes, which accounted for a $643.4 million decrease. Cost of sales associated with the marketing of refined products decreased a net $105.1 million year-to-year primarily due to lower purchase prices, which accounted for a $733.9 million decrease, which was partially offset by the impact of higher sales volumes, which accounted for a $628.8 million increase. Other operating costs and expenses increased a net $65.5 million year-to-year, which includes a $188.8 million increase primarily due to the addition of operating costs of newly constructed assets that have recently started operations and higher overall maintenance costs, partially offset by a $123.3 million reduction in operating costs due to the sale of certain trucking and distribution assets in January and April 2013.

Depreciation, amortization and accretion expenses in operating costs and expenses increased $87.2 million for 2013 when compared to 2012 primarily due to recently constructed assets being placed into service.

We recorded net gains within operating costs and expenses of $83.4 million attributable to asset sales and insurance recoveries in 2013 compared to $17.6 million in 2012. In March 2013, we sold the Stratton Ridge-to-Mont Belvieu segment of the Seminole Pipeline, along with a related storage cavern, and recognized a $52.5 million gain on the sale. We recognized $15.0 million of gains attributable to the receipt of nonrefundable cash insurance proceeds related to our West Storage claims in 2013 compared to $30.0 million of such gains in 2012. These proceeds were attributable to property damage claims we filed in connection with the February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. The remaining West Storage claims of approximately $95.0 million are anticipated to be collected during the first quarter of 2014. To the extent that additional nonrefundable cash insurance proceeds related to this incident are received, we expect to record gains equal to such proceeds.

Operating costs and expenses include $92.6 million and $63.4 million of non-cash asset impairment charges in 2013 and 2012, respectively. Our non-cash asset impairment charges for 2013 primarily relate to the abandonment of certain segments of crude oil and natural gas pipelines in Texas, Oklahoma and the Gulf of Mexico, certain refined products terminal assets in Texas, an NGL storage cavern in Arizona and an NGL fractionator and storage complex in Ohio. Our asset impairment charges for 2012 primarily relate to the abandonment of certain segments of crude oil and natural gas pipelines in Texas and the Gulf of Mexico.

General and administrative costs for 2013 increased $18.0 million when compared to 2012 primarily due to higher employee compensation expenses.

Equity income from our unconsolidated affiliates for 2013 increased $103.0 million when compared to 2012 primarily due to higher earnings from our investments in crude oil pipeline joint ventures.

Interest expense for 2013 increased $30.7 million when compared to 2012. The following table presents the components of our consolidated interest expense for the years indicated (dollars in millions):

	For the Year Ended December 31,		
	2013	**2012**	**2011**
Interest charged on debt principal outstanding	$ 911.7	$ 879.7	$ 847.9
Impact of interest rate hedging program, including related amortization	3.3	(12.6)	(22.3)
Interest cost capitalized in connection with construction projects (1)	(133.0)	(116.8)	(106.7)
Other (2)	20.5	21.5	25.2
Interest expense	$ 802.5	$ 771.8	$ 744.1

(1) Capitalized interest amounts become part of the historical cost of an asset and are charged to earnings (as a component of depreciation expense) ratably over the estimated useful life of the asset once the asset enters its intended service. Capitalized interest amounts fluctuate from period-to-period based on the timing of when projects are placed into service, our capital spending levels and the interest rates charged on borrowings.

(2) Primarily reflects facility commitment fees charged in connection with our revolving credit facilities and amortization of debt issuance costs.

Interest charged on debt principal outstanding, which is the primary driver of interest expense, increased a net $32.0 million for 2013 when compared to 2012 generally due to increased debt principal amounts outstanding during 2013, which accounted for $94.5 million of the increase, partially offset by the effect of lower overall interest rates in 2013, which accounted for a $62.5 million decrease. Our weighted-average debt principal balance for 2013 was $17.14 billion compared to $15.3 billion for 2012. In general, our debt principal balances have increased over time due to the partial debt financing of our capital spending program. For a discussion of our consolidated debt obligations and capital spending program, see "Liquidity and Capital Resources" within this Item 7.

Other non-operating income for 2012 includes $68.8 million of aggregate gains attributable to the liquidation of our investment in Energy Transfer Equity, L.P. ("Energy Transfer Equity"). At January 1, 2012, we owned 29,303,514 common units of Energy Transfer Equity representing 13.1% of its limited partner interests. On January 18, 2012, we sold 22,762,636 of these common units in a private transaction, which generated a gain on the sale of $27.5 million. As a result of the January 18, 2012 transaction, our ownership interest in Energy Transfer Equity was reduced below 3%, and we discontinued using the equity method to account for this investment and began accounting for it as an investment in available-for-sale equity securities. Following the January 18, 2012 transaction, we sold the remaining 6,540,878 Energy Transfer Equity common units through April 27, 2012, which generated gains totaling $41.3 million. All activities included in our former sixth reportable business segment, Other Investments, ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our investment in Energy Transfer Equity. See Note 13 of the Notes to Consolidated Financial

Statements included under Part II, Item 8 of this annual report for additional information regarding our business segments.

Provision for income taxes was $57.5 million in 2013, which primarily reflects our state tax obligations under the Revised Texas Franchise Tax (or “Texas Margin Tax”). However, we recognized an overall income tax benefit of $17.2 million for 2012, which was primarily due to a $45.3 million federal income tax benefit related to the conversion of certain of our subsidiaries to limited liability companies during the first quarter of 2012, partially offset by amounts recorded in connection with the Texas Margin Tax. For additional information regarding our provision for income taxes, see Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Comparison of 2012 with 2011. Revenues for 2012 decreased $1.73 billion when compared to 2011. Revenues from the marketing of crude oil increased a net $1.58 billion year-to-year primarily due to higher sales volumes, which accounted for a $2.19 billion increase, partially offset by lower sales prices, which accounted for a $609.0 million decrease. Revenues from the marketing of NGLs and natural gas decreased a net $2.98 billion year-to-year primarily due to lower sales prices, which accounted for a $4.0 billion decrease, partially offset by higher sales volumes, which accounted for a $1.02 billion increase. Revenues from the marketing of petrochemical products decreased $701.2 million year-to-year primarily due to lower sales volumes, which accounted for a $461.5 million decrease, and lower sales prices, which accounted for an additional $239.7 million decrease. Revenues from the marketing of refined products increased a net $78.3 million year-to-year primarily due to higher sales volumes, which accounted for a $95.1 million increase, partially offset by lower sales prices, which accounted for a $16.8 million decrease. Revenues from midstream asset services increased $197.7 million year-to-year primarily due to contributions from our newly constructed assets in the Eagle Ford Shale and our Acadian Haynesville Extension pipeline, which commenced operations in November 2011.

Total operating costs and expenses for 2012 decreased $1.95 billion when compared to 2011 primarily due to a $2.28 billion decrease in cost of sales. The cost of sales associated with our marketing of crude oil increased a net $1.36 billion year-to-year primarily due to higher sales volumes, which accounted for a $2.07 billion increase, partially offset by lower purchase prices, which accounted for a $708.3 million decrease. Cost of sales associated with the marketing of NGLs and natural gas decreased a net $2.94 billion year-to-year primarily due to lower purchase prices, which accounted for a $3.8 billion decrease, partially offset by higher sales volumes, which accounted for an $866.1 million increase. Cost of sales associated with our marketing of petrochemical products decreased $915.8 million year-to-year primarily due to lower sales volumes, which accounted for a $479.3 million decrease, and lower purchase prices, which accounted for an additional $436.5 million decrease. Cost of sales associated with our marketing of refined products increased $116.6 million primarily due to higher sales volumes. Other operating costs and expenses increased $49.5 million year-to-year primarily due to the addition of operating costs of newly constructed assets that have recently started operations and higher overall maintenance costs.

Depreciation, amortization and accretion expenses increased $103.0 million for 2012 when compared to 2011 primarily due to recently constructed assets being placed into service.

Gains attributable to asset sales and insurance recoveries for 2012 decreased $138.4 million when compared to 2011. In December 2011, we sold our ownership interests in a natural gas storage facility located in Mississippi and recorded a $129.1 million gain on the sale.

Non-cash asset impairment charges for 2012 increased $35.6 million when compared to 2011 primarily due to the abandonment in 2012 of certain segments of crude oil and natural gas pipelines in Texas and the Gulf of Mexico.

General and administrative costs for 2012 decreased $11.5 million when compared to 2011. Our results for 2011 included $12.0 million of transaction expenses related to the Duncan Merger.

Equity income from our unconsolidated affiliates for 2012 increased $17.9 million when compared to 2011 primarily due to improved results from the Seaway Pipeline partially offset by a decrease in equity earnings from Energy Transfer Equity. Equity earnings from our investment in the Seaway Pipeline increased $36.7 million year-to-year due to the completion of its reversal project during the second quarter of 2012. Our equity in the income of

Energy Transfer Equity was $2.4 million for 2012 compared to $14.8 million for 2011. We liquidated our remaining investment in Energy Transfer Equity common units in early 2012.

Interest expense for 2012 increased $27.7 million when compared to 2011. As presented in the interest expense table under "*Comparison of 2013 with 2012*" above, interest charged on debt principal outstanding, which is the primary driver of interest expense, increased a net $31.8 million for 2012 when compared to 2011 generally due to increased debt principal amounts outstanding during 2012, which accounted for $41.1 million of the increase, partially offset by the effect of lower overall interest rates in 2012, which accounted for a $9.3 million decrease. Our weighted-average debt principal balance for 2012 was $15.3 billion compared to $14.59 billion for 2011.

Other non-operating income for 2012 increased $72.9 million when compared to 2011 primarily due to $68.8 million of aggregate gains we recorded in connection with the liquidation of our investment in Energy Transfer Equity, which was completed in April 2012.

We recognized an income tax benefit of $17.2 million for 2012 compared to a $27.2 million provision for income taxes in 2011. The $44.4 million year-to-year change in income taxes is primarily due to a $45.3 million federal income tax benefit related to the conversion of certain of our subsidiaries to limited liability companies during the first quarter of 2012.

Business Segment Highlights

Total segment gross operating margin was $4.82 billion, $4.39 billion and $3.87 billion for 2013, 2012 and 2011, respectively. The following information highlights significant changes in our year-to-year segment results (i.e., gross operating margin amounts) and the primary drivers of such changes. The selected volume statistics presented in the tabular information for each segment are reported on a net basis, taking into account our ownership interests in certain joint ventures, and reflect the periods in which we owned an interest in such operations. These statistics reflect volumes for newly constructed assets from the dates such assets were placed into service and for purchased assets from the date of acquisition.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. For information regarding this financial metric, see "Other Items – Use of Non-GAAP Financial Measure" within this Part II, Item 7.

All activities included in our former sixth reportable business segment, Other Investments, ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our previously held investment in Energy Transfer Equity. Our equity earnings from this investment were $2.4 million and $14.8 million for 2012 and 2011, respectively.

NGL Pipelines & Services. The following table presents segment gross operating margin and selected volumetric data for the NGL Pipelines & Services segment for the years indicated (dollars in millions, volumes as noted):

	For the Year Ended December 31,		
	2013	**2012**	**2011**
Segment gross operating margin:			
Natural gas processing and related NGL marketing activities	$ 1,165.4	$ 1,443.0	$ 1,324.4
NGL pipelines and related storage	900.0	740.7	638.4
NGL fractionation	449.0	284.8	221.4
Total	$ 2,514.4	$ 2,468.5	$ 2,184.2
Selected volumetric data:			
NGL transportation volumes (MBPD)	2,787	2,472	2,284
NGL fractionation volumes (MBPD)	726	659	575
Equity NGL production (MBPD) (1)	126	101	116
Fee-based natural gas processing (MMcf/d) (2)	4,612	4,382	3,820

(1) Represents the NGL volumes we earn and take title to in connection with our processing activities. In general, equity NGL production decreased in 2012 compared to 2011 due to reduced ethane recoveries associated with the weakness in natural gas processing margins resulting from lower NGL prices. The increase in 2013 compared to 2012 is primarily due to equity NGL volumes produced at our Yoakum facility in South Texas.

(2) Volumes reported correspond to the revenue streams earned by our gas plants. The increase in fee-based processing volumes in 2013 and 2012 is primarily due to (i) the start-up of our Yoakum gas plant in May 2012 and (ii) changes in processing agreements whereby producers are electing to process more of their natural gas on a fee basis in order to retain NGLs extracted from their natural gas streams, which, in turn, also lowers our equity NGL production.

Natural gas processing and related NGL marketing activities

Comparison of 2013 with 2012. Gross operating margin from our natural gas processing and related NGL marketing activities for 2013 decreased $277.6 million when compared to 2012. Gross operating margin from our Meeker natural gas processing plant in Colorado decreased $182.4 million year-to-year primarily due to lower processing margins in 2013. In general, natural gas processing margins are lower in 2013 when compared to 2012 due to lower NGL prices and higher natural gas prices in each respective year. Gross operating margin from our Pioneer natural gas processing plant in Wyoming decreased $81.3 million year-to-year primarily due to the effects of ethane rejection and general production declines, both of which lowered equity NGL production volumes at this facility during 2013 when compared to 2012. In general, producers utilizing our Pioneer facility have curtailed their drilling programs in the Jonah and Pinedale production fields in response to continued low market prices for natural gas.

Gross operating margin from our South Texas natural gas processing plants increased a net $15.9 million year-to-year primarily due to higher volumes, which accounted for a $54.3 million increase, and higher processing fees, which resulted in a $28.6 million increase, partially offset by lower processing margins, which accounted for a $65.3 million decrease. These gas plants continue to benefit from NGL-rich natural gas production from the Eagle Ford Shale and the start-up of our Yoakum gas processing plant. The first phase (or “train”) of our new cryogenic natural gas processing plant at Yoakum, Texas commenced operations in May 2012. We placed the second and third trains at the Yoakum plant in service in August 2012 and March 2013, respectively. Gross operating margin from our remaining natural gas processing plants decreased a combined $40.4 million year-to-year primarily due to lower processing margins in 2013.

Gross operating margin from our NGL marketing activities for 2013 increased a net $44.3 million when compared to 2012 primarily due to higher sales volumes, which accounted for a $131.0 million increase, partially offset by lower sales margins, which accounted for an $87.0 million decrease.

Comparability between 2013 and 2012 gross operating margin amounts was also impacted by a $20.0 million gain related to proceeds received in a vendor settlement and a $13.7 million gain attributable to changes in a provision for certain gas plant capacity obligations, both of which were recorded in 2012.

Comparison of 2012 with 2011. Gross operating margin from our natural gas processing and related NGL marketing activities for 2012 increased $118.6 million when compared to 2011. Gross operating margin from our NGL marketing activities for 2012 increased $150.4 million when compared to 2011, of which we attribute $94.2 million of the year-to-year increase to higher sales margins and the remainder to higher sales volumes. Our South Texas natural gas processing plants posted a $57.2 million year-to-year increase in gross operating margin primarily due to higher equity NGL and fee-based processing volumes from the start-up of the first and second trains of our Yoakum facility in 2012. Gross operating margin from our Meeker natural gas processing plant increased $34.8 million year-to-year primarily due to the favorable impact of our commodity hedging activities on this facility's processing margins during 2012.

Gross operating margin from our Pioneer and Chaco natural gas processing plants decreased $115.8 million year-to-year primarily due to lower equity NGL production volumes. Gross operating margin from our Louisiana and East Texas natural gas processing plants decreased $32.6 million year-to-year primarily due to lower natural gas processing margins.

Gross operating margin for 2012 includes a $20.0 million gain related to proceeds received in a vendor settlement and a $13.7 million gain attributable to changes in a provision for certain plant capacity obligations.

NGL pipelines and related storage

Comparison of 2013 with 2012. Gross operating margin from NGL pipelines and related storage assets for 2013 increased $159.3 million when compared to 2012 primarily due to strong results from our South Texas and Houston region NGL assets and the Dixie Pipeline. Gross operating margin from our South Texas NGL Pipeline System increased $68.1 million year-to-year primarily due to a 126 MBPD increase in transportation volumes associated with Eagle Ford Shale production. Gross operating margin from our Houston Ship Channel LPG export terminal and related Channel Pipeline increased a combined $50.0 million year-to-year primarily due to increased volumes. As a result of high demand for propane export services, loading volumes at our Houston Ship Channel LPG export terminal increased 99 MBPD year-to-year and volumes transported on the related Channel Pipeline increased 108 MBPD year-to-year.

Gross operating margin from our Dixie Pipeline and related NGL terminals increased $18.2 million year-to-year primarily due to a 27 MBPD increase in transportation volumes for 2013, which accounted for $10.7 million of the increase after taking into account associated operating costs, and higher transportation and other fees, which accounted for $7.5 million of the increase. Transportation volumes on the Dixie Pipeline were negatively impacted during 2012 due to downtime associated with pipeline integrity projects and warmer than normal winter weather.

Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased a net $7.2 million year-to-year. A $43.2 million increase in revenues associated with higher system-wide tariffs and other fees, combined with a $4.3 million decrease in operating costs primarily due to pipeline gains during 2013, was partially offset by a $40.3 million decrease in gross operating margin attributable to lower transportation volumes. Transportation volumes for our Mid-America Pipeline System and Seminole Pipeline decreased a combined 75 MBPD year-to-year primarily due to lower NGL production from Rocky Mountain natural gas processing plants caused by ethane rejection and reduced demand for NGL transportation services between Conway, Kansas and Mont Belvieu, Texas.

Comparison of 2012 with 2011. Gross operating margin from our NGL pipelines and related storage business for 2012 increased $102.3 million when compared to 2011. Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased $37.2 million year-to-year primarily due to an increase in system-wide tariffs and other fees. Gross operating margin from our Mont Belvieu NGL storage business increased $22.9 million year-to-year primarily due to higher storage volumes. Gross operating margin from our Houston Ship Channel LPG export terminal and related Channel Pipeline increased $22.0 million year-to-year attributable to higher propane export volumes. Gross operating margin from our South Texas NGL Pipeline System, including the Eagle Ford NGL Pipeline placed into service in April 2012, increased $45.0 million year-to-year primarily due to higher NGL volumes associated with Eagle Ford Shale production. The foregoing year-to-year increases in gross operating margin from our NGL pipelines and related storage business were partially offset by $20.1 million of net operational measurement gains in 2011 that did not reoccur in 2012.

NGL fractionation

Comparison of 2013 with 2012. Gross operating margin from NGL fractionation for 2013 increased $164.2 million when compared to 2012 primarily due to higher fractionation fees and volumes at our Mont Belvieu complex. Our Mont Belvieu NGL fractionators have benefitted from increased mixed NGL volumes arriving at Mont Belvieu from domestic shale plays such as the Eagle Ford Shale and other producing regions such as the Rocky Mountains. Higher average fractionation and other fees during 2013 attributable to our Mont Belvieu NGL fractionators accounted for a $82.4 million year-to-year increase in gross operating margin. Also, NGL fractionation volumes at our Mont Belvieu complex increased 97 MBPD year-to-year (net to our ownership interest), which resulted in a $61.1 million year-to-year increase in gross operating margin after taking into account associated operating costs. NGL fractionation capacity at our Mont Belvieu complex increased by 170 MBPD during 2013 as a result of placing our seventh and eighth NGL fractionation units into service in September and November 2013, respectively. Overall, total NGL fractionation capacity at our Mont Belvieu complex was approximately 670 MBPD at the end of 2013.

Comparison of 2012 with 2011. Gross operating margin from NGL fractionation for 2012 increased $63.4 million when compared to 2011 primarily due to higher fractionation volumes at our Mont Belvieu complex. We placed into service our fifth and sixth NGL fractionation units at our Mont Belvieu complex during the fourth quarters of 2011 and 2012, respectively. Completion of these units increased total NGL fractionation capacity at our Mont Belvieu complex by a combined 170 MBPD.

Onshore Natural Gas Pipelines & Services. The following table presents segment gross operating margin and selected volumetric data for the Onshore Natural Gas Pipelines & Services segment for the years indicated (dollars in millions, volumes as noted):

	For the Year Ended December 31,		
	2013	2012	2011
Segment gross operating margin	$ 789.0	$ 775.5	$ 675.3
Selected volumetric data:			
Natural gas transportation volumes (BBtus/d)	12,936	13,634	13,231

Comparison of 2013 with 2012. Gross operating margin from onshore natural gas pipelines and services for 2013 increased $13.5 million when compared to 2012. Gross operating margin from our Texas Intrastate System increased $57.6 million year-to-year primarily due to higher firm capacity reservation revenues. Increased natural gas production from the Eagle Ford Shale, in large part a by-product of increased NGL and crude oil production, continues to support strong demand for our natural gas transportation services on the Texas Intrastate System. Natural gas transportation volumes for the Texas Intrastate System increased 206 BBtus/d year-to-year. Gross operating margin from our natural gas marketing activities increased $8.8 million year-to-year primarily due to higher sales margins.

Gross operating margin from our Jonah, Piceance Basin and Haynesville Gathering Systems decreased a combined $35.3 million year-to-year primarily due to lower gathering volumes. Gross operating margin from our San Juan Gathering System increased a net $0.4 million year-to-year primarily due to higher gathering fees, which are indexed to natural gas prices and accounted for a $16.2 million increase, partially offset by the effects of lower volumes, which accounted for a $15.8 million decrease. Producers served by these four gathering systems have curtailed their drilling programs in response to the continued low price of natural gas. Collectively, natural gas transportation volumes for these four gathering systems decreased 805 BBtus/d year-to-year.

Gross operating margin from our Acadian Gas System decreased $14.4 million year-to-year primarily due to higher operating expenses, which accounted for $6.3 million of the decrease, and lower sales margins, which accounted for a $5.1 million decrease. Transportation volumes for our Acadian Gas System declined a net 63 BBtus/d year-to-year primarily due to lower volumes from the Haynesville supply basin.

Overall, natural gas transportation volumes for 2013 decreased a net 698 BBtus/d when compared to 2012 primarily due to a combined 868 BBtus/d decrease in volumes for 2013 on our Jonah, Piceance Basin, Haynesville, Acadian and San Juan systems partially offset by increased volumes of 206 BBtus/d on our Texas Intrastate System for 2013.

Comparison of 2012 with 2011. Gross operating margin from onshore natural gas pipelines and services for 2012 increased $100.2 million when compared to 2011. Gross operating margin from our Acadian Gas System increased $142.5 million year-to-year primarily due to contributions from our Haynesville Extension pipeline. The Haynesville Extension of our Acadian Gas System commenced operations in November 2011 and transported 1.4 TBtus/d of natural gas during 2012. Gross operating margin from our Texas natural gas pipelines and related storage assets increased $86.4 million year-to-year primarily due to higher firm capacity reservation revenues on the Texas Intrastate System.

Gross operating margin from our San Juan Gathering System decreased $31.2 million year-to-year primarily due to lower gathering and related fees. Gathering fees on our San Juan system are impacted by changes in regional natural gas prices, which decreased on average 31% year-to-year. Gross operating margin from our natural gas marketing activities decreased $24.4 million year-to-year primarily due to lower sales margins. Gross operating margin from our Jonah Gathering System decreased $17.6 million year-to-year primarily due to lower throughput volumes. Likewise, gross operating margin from our Central Treating Facility in Colorado decreased $9.8 million year-to-year due to lower volumes. Lastly, gross operating margin decreased $38.4 million year-to-year primarily due to the sale of our Mississippi natural gas storage business in December 2011.

Onshore Crude Oil Pipelines & Services. The following table presents segment gross operating margin and selected volumetric data for the Onshore Crude Oil Pipelines & Services segment for the years indicated (dollars in millions, volumes as noted):

	For the Year Ended December 31,		
	2013	**2012**	**2011**
Segment gross operating margin	$ 742.7	$ 387.7	$ 234.0
Selected volumetric data:			
Crude oil transportation volumes (MBPD)	1,175	828	678

Comparison of 2013 with 2012. Gross operating margin from our onshore crude oil pipelines and services business for 2013 increased $355.0 million when compared to 2012 primarily due to higher volumes on our crude oil pipeline systems and improved results from our crude oil marketing activities. Gross operating margin from our South Texas Crude Oil Pipeline System increased $192.3 million year-to-year primarily due to a 107 MBPD increase in volumes on the Eagle Ford Expansion pipeline. Gross operating margin from our investments in the Seaway Pipeline and Eagle Ford Crude Oil Pipeline System increased a combined $110.6 million year-to-year primarily due to an aggregate 193 MBPD increase in transportation volumes (net to our interest) on these pipelines. Lastly, gross operating margin from our crude oil marketing and related activities increased $30.3 million year-to-year primarily due to higher sales volumes.

Comparison of 2012 with 2011. Gross operating margin from our onshore crude oil pipelines and services business for 2012 increased $153.7 million when compared to 2011. Gross operating margin from our crude oil marketing and related activities increased $59.7 million year-to-year primarily due to higher sales margins, which accounted for $35.5 million of the increase, and sales volumes, which accounted for the remaining increase. Our crude oil marketing activities benefitted from increased crude oil production volumes from supply basins in the Eagle Ford Shale, Permian Basin and Rocky Mountains regions. Gross operating margin from our South Texas Crude Oil Pipeline System increased $55.7 million year-to-year primarily due to higher transportation volumes attributable to the Eagle Ford Expansion pipeline. Equity earnings from our investment in the Seaway Pipeline increased $36.7 million year-to-year primarily due to the Seaway Pipeline commencing the southbound delivery of crude oil in May 2012.

Offshore Pipelines & Services. The following table presents segment gross operating margin and selected volumetric data for the Offshore Pipelines & Services segment for the years indicated (dollars in millions, volumes as noted):

	For the Year Ended December 31,		
	2013	**2012**	**2011**
Segment gross operating margin	$ 146.1	$ 173.0	$ 228.2
Selected volumetric data: (1)			
Natural gas transportation volumes (BBtus/d)	678	853	1,065
Crude oil transportation volumes (MBPD)	307	300	279
Platform natural gas processing (MMcf/d)	202	291	405
Platform crude oil processing (MBPD)	16	17	17

In April 2010, in an event unrelated to our operations, the Deepwater Horizon drilling rig caught fire and sank in the Gulf of Mexico, resulting in an oil spill. As a result, governmental agencies took actions to halt most drilling operations in the Gulf of Mexico for a period of time extending into late 2010. The moratorium impacted the timing of exploration and production activities in the Gulf of Mexico, with such activities only recently reaching pre-moratorium levels.

In general, regulations resulting from the Deepwater Horizon incident have made it more difficult for producers to obtain governmental approvals for offshore exploration and production activities. To the extent that new regulations or other governmental actions significantly curtail such exploration and production activities in the Gulf of Mexico, it could have a material adverse effect on our offshore operations.

Comparison of 2013 with 2012. Gross operating margin from our offshore pipelines and services business for 2013 decreased $26.9 million when compared to 2012. In the aggregate, gross operating margin from our Independence Hub platform and Independence Trail pipeline decreased $24.7 million year-to-year primarily due to the expiration of contractual platform demand fees during the first quarter of 2012, which accounted for $9.7 million of the decrease, and lower platform processing and pipeline throughput volumes during 2013, which accounted for $16.0 million of the decrease. Natural gas processing volumes on the Independence Hub platform decreased 88 MMcf/d year-to-year (71 MMcf/d net to our interest) and natural gas transportation volumes on the Independence Trail pipeline decreased 73 BBtus/d year-to-year. Gross operating margin from our High Island Offshore System ("HIOS") decreased $3.4 million year-to-year primarily due to a 37 BBtus/d decrease in natural gas transportation volumes. Equity earnings from our investment in Neptune Pipeline Company, L.L.C. ("Neptune") include a $4.8 million non-cash impairment charge recorded in 2013 as a result of declining pipeline throughput volumes forecast for Neptune's pipeline systems in 2014 and future years.

Collectively, gross operating margin from our Shenzi and Constitution Oil Pipelines decreased $7.4 million year-to-year. These pipelines experienced a combined 13 MBPD decrease in throughput volumes primarily due to production declines. Equity earnings from our investment in the Cameron Highway Oil Pipeline increased $7.8 million year-to-year primarily due to a 22 MBPD increase (net to our interest) in crude oil transportation volumes.

Gross operating margin for this segment also benefited from a $6.5 million year-to-year decrease in insurance costs. Due to the high cost of windstorm insurance coverage for our offshore Gulf of Mexico assets, we elected to self-insure these assets during the annual policy period extending from June 2012 to June 2013. We continue to self-insure these assets for the current annual policy period, which extends from June 2013 to June 2014. For a discussion of insurance-related matters, see "Other Items – Insurance Matters" within this Part II, Item 7.

Comparison of 2012 with 2011. Gross operating margin from our offshore pipelines and services business for 2012 decreased $55.2 million when compared to 2011. Collectively, gross operating margin from our Independence Hub platform and Independence Trail pipeline decreased $68.2 million year-to-year primarily due to lower throughput volumes and contractual platform demand fee revenues during 2012 versus 2011. Producers connected to our Independence Hub platform paid us $54.6 million of demand fees annually for five years beginning in March 2007 until that period expired in March 2012. Expiration of these contractual platform demand fees resulted in a $44.9 million year-to-year decrease in gross operating margin.

Collectively, gross operating margin from our Anaconda Natural Gas Gathering System and Constitution and Poseidon Crude Oil Pipelines increased $22.4 million year-to-year primarily due to natural gas and crude oil production from the Caesar/Tonga development in the Green Canyon area of the Gulf of Mexico that commenced in March 2012. This increase was partially offset by a collective $8.0 million year-to-year decrease in gross operating margin from our Viosca Knoll and HIOS natural gas systems primarily due to lower transportation volumes in 2012.

Petrochemical & Refined Products Services. The following table presents segment gross operating margin and selected volumetric data for the Petrochemical & Refined Products Services segment for the years indicated (dollars in millions, volumes as noted):

	For the Year Ended December 31,		
	2013	**2012**	**2011**
Segment gross operating margin:			
Propylene fractionation and related activities	$ 134.7	$ 193.1	$ 161.2
Butane isomerization and related operations	99.2	95.8	124.9
Octane enhancement and related plant operations	154.7	100.9	109.1
Refined products pipelines and related activities	164.6	89.9	79.6
Marine transportation and other	72.7	100.2	60.4
Total	$ 625.9	$ 579.9	$ 535.2
Selected volumetric data:			
Propylene fractionation volumes (MBPD)	74	72	73
Butane isomerization volumes (MBPD)	94	95	101
Standalone DIB processing volumes (MBPD)	67	46	28
Octane additive and related plant production volumes (MBPD)	20	16	17
Transportation volumes, primarily refined products and petrochemicals (MBPD)	702	689	783

Propylene fractionation and related activities

Comparison of 2013 with 2012. Gross operating margin from our propylene fractionation and related activities for 2013 decreased $58.4 million when compared to 2012 primarily due to lower propylene sales margins in 2013, which accounted for a $62.7 million decrease, partially offset by higher transportation fees on North Dean Pipeline, which accounted for a $6.2 million increase.

Comparison of 2012 with 2011. Gross operating margin from our propylene fractionation and related activities for 2012 increased $31.9 million when compared to 2011 primarily due to higher propylene sales margins in 2012.

Butane isomerization and deisobutanizer operations

Comparison of 2013 with 2012. Gross operating margin from these operations increased an aggregate $3.4 million for 2013 when compared to 2012. Gross operating margin from our standalone deisobutanizers ("DIBs"), which are used to process mixed butanes from our NGL fractionation operations, increased $7.8 million for 2013 when compared to 2012. We added a new DIB unit at our Mont Belvieu facility in March 2013, which accounted for $5.6 million of gross operating margin for the year and 27 MBPD of additional processing volumes.

Gross operating margin from butane isomerization decreased a net $4.5 million in 2013 when compared to 2012 primarily due to increased operating costs, which accounted for an $11.6 million decrease, partially offset by higher by-product sales volumes, which accounted for a $6.6 million increase, and isomerization fees, which accounted for an additional $3.2 million increase.

Operating costs for 2013 were higher than in 2012 primarily due to an $8.4 million increase in maintenance costs, which in turn was primarily due to work completed at two of our isomerization units during the fourth quarter of 2013.

Comparison of 2012 with 2011. Gross operating margin from these operations for 2012 decreased a combined $29.1 million when compared to 2011. Gross operating margin from butane isomerization decreased

$24.9 million year-to-year primarily due to lower isobutane production volumes (and corresponding by-product volumes and sales) and processing fees. High purity isobutane production volumes for 2012 were negatively impacted by extended downtime for maintenance at our octane enhancement facility. The decrease in by-product production and sales during 2012 accounted for $18.6 million of the year-to-year decrease, with $10.5 million of this decrease due to lower sales prices and $8.1 million attributable to lower volumes. Lower isomerization fees accounted for an additional $6.1 million of the year-to-year decrease. Gross operating margin from our standalone DIBs decreased $3.6 million year-to-year primarily due to higher operating costs.

Octane enhancement and HPIB plant operations

Comparison of 2013 with 2012. Gross operating margin from our octane enhancement and high purity isobutylene ("HPIB") plant operations increased a combined $53.8 million for 2013 when compared to 2012. Our octane enhancement facility experienced extended periods of downtime for maintenance during 2012, which negatively impacted the facility's operating results for that year. The $53.8 million increase in gross operating margin for 2013 is primarily due to higher sales volumes, which accounted for a $40.0 million increase, and higher sales margins, which accounted for a $29.0 million increase, partially offset by higher operating costs, which accounted for a $16.8 million decrease.

Comparison of 2012 with 2011. Gross operating margin from octane enhancement and HPIB plant operations for 2012 decreased a combined $8.2 million when compared to 2011. An estimated $27.1 million year-to-year increase in gross operating margin attributable to higher product sales margins was more than offset by the combined effects of a $19.5 million decrease due to lower sales volumes and $15.8 million of higher operating expenses in 2012. Our octane enhancement facility experienced extended periods of downtime during 2012, which negatively impacted sales volumes and increased operating costs.

Refined products pipelines and related activities

Comparison of 2013 with 2012. Gross operating margin from our refined products pipelines and related marketing activities for 2013 increased $74.7 million when compared to 2012 primarily due to improved results from our TE Products Pipeline and refined products terminals and related marketing activities. Gross operating margin from our TE Products Pipeline increased a net $24.7 million year-to-year primarily due to higher transportation fees, which accounted for a $52.3 million increase, partially offset by a $28.0 million decrease in gross operating margin attributable to lower refined products interstate transportation volumes. The higher transportation fees year-to-year include a $24.3 million benefit recognized in connection with the settlement of a rate case with certain shippers during the second quarter of 2013. Gross operating margin from our refined products terminals increased $27.8 million year-to-year primarily due to a $16.6 million benefit attributable to reductions in a provision for future pipeline capacity obligations recorded in the first quarter of 2013. Results from our refined products marketing activities increased $21.8 million year-to-year primarily due to higher sales margins, which accounted for a $15.7 million increase, and higher sales volumes, which accounted for a $6.1 million increase.

Comparison of 2012 with 2011. Gross operating margin from refined products pipelines and related marketing activities for 2012 increased $10.3 million when compared to 2011. Gross operating margin from our TE Products Pipeline increased $4.9 million year-to-year primarily due to a $44.1 million decrease in operating costs and expenses. Our TE Products Pipeline incurred $31.2 million of costs in 2011 related to the repair of pipeline leaks in New York State, Texas and Louisiana. The remainder of the year-to-year decrease in operating costs and expenses is primarily due to lower expenses in 2012 for operating gains and losses and costs related to transmix (i.e., the comingling of two purity products in a pipeline). Revenues earned by our TE Products Pipeline from the transportation of refined products and NGLs decreased $36.5 million year-to-year primarily due to a 26 MBPD decrease in NGL volumes delivered to Northeast U.S. markets and a 44 MBPD decrease in refined products volumes delivered to Midwest U.S. markets. In general, warmer weather during 2012 compared to 2011 resulted in lower demand for propane used as heating fuel, while shipments of refined products from the Gulf Coast to Midwest markets decreased as a result of lower prices for such products in Midwestern markets than in Gulf Coast markets. Structural shifts in population, reduced demand and increased refinery production in the Midwest have contributed to a decline in demand for the transportation of refined products from the Gulf Coast to the Midwest. Gross operating margin from the marketing of refined products increased $4.8 million year-to-year primarily due to higher sales margins during 2012.

Marine transportation and other

Comparison of 2013 with 2012. Gross operating margin from our marine transportation and other segment services for 2013 decreased $27.5 million when compared to 2012. Results attributable to our marine transportation business for 2012 included a $24.0 million gain recorded in connection with a legal settlement. Excluding the effect of the 2012 legal settlement, gross operating margin from our marine transportation business increased $8.8 million year-to-year primarily due to higher fees.

Gross operating margin from other segment services decreased $12.3 million year-to-year primarily due to the sale of our petrochemical trucking and lubrication oil and specialty chemical distribution assets during 2013. These businesses posted gross operating margin of $11.2 million for 2012 compared to a loss of $1.1 million for 2013.

Comparison of 2012 with 2011. Gross operating margin from marine transportation and other segment services for 2012 increased $39.8 million when compared to 2011. Results for 2012 include a $24.0 million gain recorded in connection with a legal settlement. The remainder of the year-to-year increase in gross operating margin is primarily due to the combination of $10.4 million in higher marine transportation fees and a $4.7 million decrease in operating expenses associated with our fleet of marine vessels during 2012.

Liquidity and Capital Resources

At December 31, 2013, we had $4.1 billion of consolidated liquidity, which is defined as unrestricted cash on hand plus borrowing capacity available under EPO's bank facilities. Unrestricted cash on hand at December 31, 2013 was $56.9 million. Based on current market conditions (as of the filing date of this annual report), we believe we will have sufficient liquidity, cash flow from operations and access to capital markets to fund our capital expenditures and working capital needs.

We expect to issue additional equity and debt securities to assist us in meeting our future liquidity requirements, including those related to capital spending. In June 2013, we filed with the SEC a new universal shelf registration statement (the "2013 Shelf") that replaced our prior universal shelf registration statement filed with the SEC in July 2010 (the "2010 Shelf"). The 2013 Shelf allows (and the prior 2010 Shelf allowed) Enterprise Products Partners L.P. and EPO (each on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively.

In October 2013, we filed a registration statement with the SEC covering the issuance of up to $1.25 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings. Pursuant to the "at-the-market" program, we may sell common units under an equity distribution agreement between Enterprise Products Partners L.P. and certain broker-dealers from time-to-time by means of ordinary brokers' transactions through the NYSE at market prices, in block transactions or as otherwise agreed to with the broker-dealer parties to the agreement. The new registration statement replaced our prior registration statement with respect to the at-the-market program, which was filed with the SEC in March 2012 and covered the issuance of up to $1.0 billion of our common units. After giving effect to sales of common units under the at-the-market program from its inception through February 1, 2014, we have the capacity to issue additional common units up to an aggregate sales price of $1.25 billion.

Consolidated Debt

We had $17.36 billion of principal amounts outstanding under consolidated debt agreements at December 31, 2013. The following table presents scheduled maturities of our consolidated debt obligations outstanding at December 31, 2013 for the periods indicated (dollars in millions):

		Scheduled Maturities of Debt					
	Total	**2014**	**2015**	**2016**	**2017**	**2018**	**After 2018**
Commercial Paper Notes	$ 475.0	$ 475.0	$ --	$ --	$ --	$ --	$ --
Senior Notes	15,350.0	650.0	1,300.0	750.0	800.0	350.0	11,500.0
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Total	$ 17,357.7	$ 1,125.0	$ 1,300.0	$ 750.0	$ 800.0	$ 350.0	$ 13,032.7

Long-term and current maturities of debt reflect the classification of such obligations at December 31, 2013 after taking into consideration EPO's issuance of long-term senior notes in February 2014 and the use of net proceeds received from the offering to repay debt, as described below.

The following information describes significant transactions that affected our consolidated debt obligations during the year ended December 31, 2013:

Senior Notes Transactions. In March 2013, EPO issued $1.25 billion in principal amount of 3.35% senior notes due March 2023 ("Senior Notes HH") and $1.0 billion in principal amount of 4.85% senior notes due March 2044 ("Senior Notes II"). Senior Notes HH were issued at 99.908% of their principal amount and Senior Notes II were issued at 99.619% of their principal amount. Net proceeds from the issuance of Senior Notes HH and II were used to repay debt, including (i) amounts outstanding under EPO's $3.5 Billion Multi-Year Revolving Credit Facility and commercial paper program (which EPO used to repay $550.0 million principal amount of senior notes that matured in February 2013) and (ii) $650.0 million principal amount of senior notes that matured in April 2013, and for general company purposes.

In February 2014, EPO issued $850 million in principal amount of 3.90% senior notes due February 2024 ("Senior Notes JJ") and $1.15 billion in principal amount of 5.10% senior notes due February 2045 ("Senior Notes KK"). Senior Notes JJ were issued at 99.811% of their principal amount and Senior Notes KK were issued at 99.845% of their principal amount. Net proceeds of $1.98 billion from the issuance of Senior Notes JJ and KK were used to repay debt, including amounts then outstanding under EPO's $3.5 Billion Multi-Year Revolving Credit Facility and commercial paper program (which EPO used to repay $500.0 million in principal amount of Senior Notes O that matured in January 2014), and for general company purposes.

Enterprise Products Partners L.P. has unconditionally guaranteed Senior Notes HH, II, JJ and KK on an unsecured and unsubordinated basis. These senior notes rank equal with EPO's existing and future unsecured and unsubordinated indebtedness and are senior to any existing and future subordinated indebtedness of EPO. These senior notes are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability (with certain exceptions) to incur debt secured by liens and engage in sale and leaseback transactions.

364-Day Credit Agreement. In June 2013, EPO entered into a 364-Day Revolving Credit Agreement with a group of lenders (the "364-Day Credit Agreement"). Under the terms of the 364-Day Credit Agreement, EPO may borrow up to $1.0 billion at a variable interest rate for a term of 364 days, subject to the terms and conditions set forth therein. Borrowings under this credit agreement provide us with an additional source of liquidity to fund our capital spending program.

EPO's obligations under the 364-Day Credit Agreement are not secured by any collateral; however, they are guaranteed by Enterprise Products Partners L.P. Amounts borrowed under the 364-Day Credit Agreement mature on June 18, 2014, although EPO may, between 15 and 60 days prior to the maturity date, elect to have the entire principal balance then outstanding continued as a non-revolving term loan for a period of one additional year, payable on June 18, 2015.

The 364-Day Credit Agreement contains customary representations, warranties, covenants (affirmative and negative) and events of default, the occurrence of which would permit the lenders to accelerate the maturity date of amounts borrowed under the 364-Day Credit Agreement. The 364-Day Credit Agreement also restricts EPO's ability to pay cash distributions to its parent, Enterprise Products Partners L.P., if a default or an event of default (as defined in the 364-Day Credit Agreement) has occurred and is continuing at the time such distribution is scheduled to be paid.

First Amendment to $3.5 Billion Multi-Year Revolving Credit Facility. In June 2013, EPO amended the terms of its $3.5 Billion Multi-Year Revolving Credit Facility to, among other things, extend the maturity date of commitments under the agreement from September 2016 to June 2018 and lower the applicable margin on borrowings.

For additional information regarding our consolidated debt obligations, see Note 11 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Issuance of Common Units

The following table summarizes the issuance of Enterprise common units during the years indicated in connection with underwritten equity offerings, the at-the-market program, and quarterly DRIP and employee unit purchase plan ("EUPP") (dollars in millions, number of units issued as shown):

	Number of Common Units Issued	Net Cash Proceeds Received
Year Ended December 31, 2011:		
Common units issued in connection with underwritten offering	10,350,000	$ 448.5
Common units issued in connection with the DRIP and EUPP	2,337,904	94.4
Total	12,687,904	$ 542.9
Year Ended December 31, 2012:		
Common units issued in connection with underwritten offering	9,200,000	$ 473.3
Common units issued in connection with the at-the-market program (1)	3,978,545	203.8
Common units issued in connection with the DRIP and EUPP	2,814,660	139.7
Total	15,993,205	$ 816.8
Year Ended December 31, 2013:		
Common units issued in connection with underwritten offerings	18,400,000	$ 1,039.6
Common units issued in connection with the at-the-market program	7,624,689	456.3
Common units issued in connection with the DRIP and EUPP	5,154,127	296.1
Total	31,178,816	$ 1,792.0

(1) The sale of common units under the at-the-market program was initiated during the third quarter of 2012.

The following information describes significant transactions that affected our partners' equity accounts during the year ended December 31, 2013:

Underwritten equity offerings. In February 2013, we issued 9,200,000 common units to the public (including an over-allotment amount of 1,200,000 common units) at an offering price of $54.56 per unit, which generated net cash proceeds of $486.6 million. In November 2013, we issued an additional 9,200,000 common units to the public (including an over-allotment amount of 1,200,000 common units) at an offering price of $62.05 per unit. This underwritten offering generated net cash proceeds of $553.0 million.

At-the-market program. During the year ended December 31, 2013, we sold 7,624,689 common units under our at-the-market program for aggregate gross cash proceeds of $460.4 million, resulting in total net cash proceeds of $456.3 million.

DRIP and EUPP. We also have registration statements on file with the SEC collectively authorizing the issuance of up to 70,000,000 of our common units in connection with our 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 our common units they own by reinvesting the quarterly cash distributions they receive from us into the purchase of additional new common units. We issued a total of 5,012,414 common units under our DRIP during the year ended December 31, 2013, which generated net cash proceeds of $287.6 million. After taking into account the number of common units issued under the DRIP through December 31, 2013, we have the capacity to issue an additional 18,480,878 common units under this plan.

During the year ended December 31, 2013, affiliates of privately held EPCO reinvested $100.0 million, resulting in the issuance of 1,749,498 common units under our DRIP (this amount being a component of the total common units issued in total under the DRIP during 2013). These same affiliates have expressed an interest in acquiring up to $100 million of additional common units through our DRIP during 2014. Their first $25.0 million reinvestment was made in February 2014 and resulted in the issuance of 403,315 of our common units.

In addition to the DRIP, we have registration statements on file with the SEC authorizing the issuance of our common units in connection with our EUPP. In September 2013, our unitholders approved the amendment and restatement of the EUPP. As a result, the maximum number of common units issuable under the EUPP increased from 440,879 common units to 4,000,000 common units. In addition, the term of the EUPP was extended to September 2023. We issued 141,713 common units under our EUPP during the year ended December 31, 2013, which generated net cash proceeds of $8.5 million. After taking into account the number of common units issued under the EUPP through December 31, 2013, we may issue an additional 3,713,444 common units under the amended and restated EUPP.

Use of proceeds. The net cash proceeds we received from the issuance of common units during the year ended December 31, 2013 were used to temporarily reduce amounts outstanding under EPO's Multi-Year Revolving Credit Facility and commercial paper program and for general company purposes.

For additional information regarding our issuance of common units and related registration statements, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Credit Ratings

As of March 3, 2014, the investment-grade credit ratings of EPO's long-term senior unsecured debt securities were BBB+ from Standard and Poor's and Baa1 from Moody's. In addition, the credit ratings of EPO's short-term senior unsecured debt securities were A-2 from Standard and Poor's and P-2 from Moody's. Fitch Ratings issued non-solicited ratings of BBB+ and F-2 for EPO's long-term senior unsecured debt securities and short-term senior unsecured debt securities, respectively.

EPO's credit ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any of our securities. A credit rating can be revised upward or downward or withdrawn at any time by a rating agency, if it determines that circumstances warrant such a change. A credit rating from one rating agency should be evaluated independently of credit ratings from other rating agencies.

Cash Flows from Operating, Investing and Financing Activities

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

	For the Year Ended December 31,		
	2013	**2012**	**2011**
Net cash flows provided by operating activities	$ 3,865.5	$ 2,890.9	$ 3,330.5
Cash used in investing activities	$ 4,257.5	$ 3,018.8	$ 2,777.6
Cash provided by (used in) financing activities	$ 432.8	$ 124.2	$ (598.6)

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

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

Comparison of 2013 with 2012

***Operating Activities*.** Net cash flows provided by operating activities for the year ended December 31, 2013 increased $974.6 million when compared to the year ended December 31, 2012. The increase in cash provided by operating activities was primarily due to:

§ a $356.1 million increase in cash attributable to higher partnership income in 2013 compared to 2012 (after adjusting our $179.1 million year-to-year increase in net income for changes in the non-cash items identified on our Statements of Consolidated Cash Flows);

§ a $134.9 million increase in cash distributions from unconsolidated affiliates for 2013 compared to 2012 primarily due to improved results from our investments in crude oil pipeline joint ventures;

§ a $169.8 million year-to-year increase in cash attributable to the timing of cash receipts and disbursements related to operations; and

§ a $266.4 million decrease in cash used for inventories.

For information regarding significant year-to-year changes in our consolidated net income and underlying segment results, see "Results of Operations" within this Part II, Item 7.

***Investing Activities*.** Cash used in investing activities for the year ended December 31, 2013 increased $1.24 billion when compared to the year ended December 31, 2012. The year-to-year increase in cash used for investing activities was primarily due to higher investments in unconsolidated affiliates to fund their capital spending programs and lower cash proceeds received from asset sales, partially offset by lower cash payments for consolidated property, plant and equipment. Investments in unconsolidated affiliates increased $484.6 million for 2013 compared to 2012 primarily due to contributions we made in connection with expansion projects for the Seaway Pipeline, Texas Express Pipeline, Front Range Pipeline and Eagle Ford Crude Oil Pipeline joint ventures.

Proceeds from asset sales and insurance recoveries decreased from $1.20 billion for 2012 to $280.6 million for 2013. Proceeds for 2012 include the $1.1 billion we received in connection with sales of common units of Energy Transfer Equity, L.P. ("Energy Transfer Equity"). For additional information regarding the liquidation of our investment in Energy Transfer Equity, see Note 9 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report. Proceeds for 2013 primarily reflect $86.9 million we received from the sale of the Stratton Ridge-to-Mont Belvieu segment of the Seminole Pipeline, $65.0 million from the sale of certain pipeline linefill volumes, $35.3 million we received from the sale of lubrication oil and specialty chemical distribution assets and $29.5 million we received from the sale of chemical trucking assets.

Capital spending for consolidated property, plant and equipment, net of contributions in aid of construction costs, decreased $216.3 million for 2013 compared to 2012.

***Financing Activities*.** Cash provided by financing activities increased $308.6 million for the year ended December 31, 2013 compared to the year ended December 31, 2012. The year-to-year increase in cash flows provided by financing activities was primarily due to the following:

§ Net cash proceeds from the issuance of common units in 2013 increased $975.2 million when compared to 2012. We issued an aggregate of 31,178,816 common units in connection with two underwritten offerings, our at-the-market program and DRIP and EUPP during 2013, which collectively generated $1.79 billion of net cash proceeds. This compares to an aggregate 15,993,205 common units we issued in connection with an underwritten offering, our at-the-market program and DRIP and EUPP during 2012, which collectively generated $816.8 million of net cash proceeds;

§ Cash contributions from noncontrolling interests increased $108.8 million year-to-year primarily due to contributions we received from Western Gas in connection with a new joint venture involving two NGL fractionators at our complex in Mont Belvieu, Texas; partially offset by

§ Cash distributions paid to limited partners in 2013 increased $221.7 million when compared to 2012 due to increases in both the number of distribution-bearing common units outstanding and the quarterly cash distribution rates per unit; and

§ Net borrowings under our consolidated debt agreements decreased $514.5 million year-to-year. EPO issued $2.25 billion and repaid $1.2 billion in principal amount of senior notes during 2013, compared to the issuance of $2.5 billion and repayment of $1.0 billion in principal amount of senior notes during 2012. In addition, net cash inflows attributable to the issuance of short-term notes under EPO’s commercial paper program were $127.2 million for 2013 compared to $346.4 million for 2012. Lastly, net repayments under EPO’s $3.5 Billion Multi-Year Revolving Credit Facility were $150.0 million for 2012.

Comparison of 2012 with 2011

***Operating Activities*.** Net cash flows provided by operating activities for the year ended December 31, 2012 decreased $439.6 million when compared to the year ended December 31, 2011. The year-to-year decrease in cash provided by operating activities was primarily due to:

§ a $485.8 million year-to-year decrease in cash generally due to the timing of cash receipts and disbursements related to operations;

§ a $363.6 million increase in cash used for inventories

§ an $80.6 million decrease in cash distributions from Energy Transfer Equity (we liquidated our investment in this entity in April 2012); partially offset by

§ a $442.5 million increase in cash attributable to higher partnership income in 2012 compared to 2011 (after adjusting our $339.7 million year-to-year increase in net income for changes in the non-cash items identified on our Statements of Consolidated Cash Flows); and

§ a $39.7 million increase in distributions from investments in crude oil pipeline joint ventures.

***Investing Activities*.** Cash used in investing activities for the year ended December 31, 2012 increased $241.2 million when compared to the year ended December 31, 2011 primarily due to increased investments in unconsolidated affiliates, partially offset by reduced capital expenditures and higher proceeds from asset sales. Investments in unconsolidated affiliates increased $579.5 million year-to-year primarily due to capital expenditures incurred in connection with modifications to and expansion of the Seaway Pipeline, construction of the Texas Express Pipeline and those involving the Eagle Ford Crude Oil Pipeline. Capital spending for consolidated property, plant and equipment, net of contributions in aid of construction costs, decreased $244.1 million year-to-year. Lastly, proceeds from asset sales and insurance recoveries increased $145.0 million year-to-year primarily due to the liquidation of our remaining investment in Energy Transfer Equity in 2012.

Financing Activities. Cash provided by financing activities was $124.2 million for the year ended December 31, 2012 compared to cash used in financing activities of $598.6 million for the year ended December 31, 2011. The $722.8 million change in cash flows from financing activities was primarily due to the following:

§ Net borrowings under our consolidated debt agreements increased $738.4 million year-to-year. EPO issued $2.5 billion and repaid $1.0 billion in principal amount of senior notes during 2012, compared to the issuance of $2.75 billion and repayment of $450.0 million in principal amount of senior notes during 2011. In addition, net repayments under our consolidated revolving bank credit facilities, term loans and other debt obligations decreased $1.19 billion year-to-year. Lastly, net cash inflows attributable to the issuance of short-term notes under EPO's commercial paper program, which was initiated in 2012, were $346.4 million;

§ Net cash proceeds from the issuance of common units in 2012 increased $273.9 million when compared to 2011. We issued an aggregate of 15,993,205 common units in connection with an underwritten offering, our at-the-market program and DRIP and EUPP during 2012, which collectively generated $816.8 million of net cash proceeds. This compares to an aggregate of 12,687,904 common units we issued in connection with an underwritten offering and our DRIP and EUPP during 2011, which collectively generated $542.9 million of net cash proceeds; partially offset by

§ Cash distributions paid to limited partners in 2012 increased $204.3 million when compared to 2011 due to increases in both the number of distribution-bearing common units outstanding and the quarterly cash distribution rates per unit; and

§ Cash outflows related to the monetization of interest rate derivative instruments increased $124.6 million year-to-year. In connection with senior notes issued in 2012, we settled a number of forward starting and fixed-to-floating interest rate swaps resulting in a combined net cash outflow of $147.8 million. In connection with senior notes issued in 2011, we settled a number of forward starting swaps and treasury locks resulting in a net cash outflow of $23.2 million. For information regarding our interest rate hedging activities, see Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Designated Units Issued in Connection with Holdings Merger

In November 2010, we completed the merger of Enterprise GP Holdings L.P. with one of our wholly owned subsidiaries (the "Holdings Merger"). In connection with the Holdings Merger, a privately held affiliate of EPCO agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from us with respect to a certain number of our common units it owns (the "Designated Units"). Distributions paid during the year ended December 31, 2013 excluded 23,700,000 Designated Units. Distributions to be paid, if any, during the years ended December 31, 2014 and 2015 will exclude 22,560,000 Designated Units and 17,690,000 Designated Units, respectively.

Conversion of Class B Units to Common Units in 2013

In October 2009, we completed the merger of one of our wholly owned subsidiaries with TEPPCO Partners, L.P. ("TEPPCO"). In connection with this merger, we issued 4,520,431 Class B units to a privately held affiliate of EPCO. The Class B units were entitled to vote together with our common units as a single class on partnership matters and generally had the same rights and privileges as our common units, except that the Class B units were not entitled to receive regular quarterly cash distributions until they automatically converted into an equal number of our common units. This conversion took place in August 2013.

Capital Spending

An important part of our business strategy involves expansion through growth capital projects, business combinations and investments in joint ventures. We believe that we are positioned to continue to expand our system of assets through the construction of new facilities and to capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities in the Rocky Mountains, Mid-Continent, Northeast and U.S. Gulf Coast regions, including the Niobrara, Barnett, Eagle Ford, Permian, Haynesville, Marcellus and Utica Shale plays and deepwater Gulf of Mexico production fields.

Although our current focus is on expansion through growth capital projects, management continues to analyze potential business combinations, asset 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 believe this trend will continue and we expect independent oil and natural gas companies to consider similar divestitures.

See "Significant Recent Developments" within this Part II, Item 7 for information regarding our current major capital projects, including the completion of several new NGL pipelines such as the Front Range Pipeline, Texas Express Pipeline and ATEX Express pipeline.

The following table summarizes our capital spending for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2013	2012	2011
Capital spending for property, plant and equipment, net: (1)			
Growth capital projects (2)	$ 3,088.0	$ 3,232.7	$ 3,552.3
Sustaining capital projects (3)	294.2	365.8	290.3
Investments in unconsolidated affiliates	1,094.1	609.5	30.0
Other investing activities	1.0	43.1	22.4
Total capital spending	$ 4,477.3	$ 4,251.1	$ 3,895.0

(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 pipeline construction projects and production well tie-ins. Contributions in aid of construction costs were $26.0 million, $23.4 million and $24.9 million for the years ended December 31, 2013, 2012 and 2011, respectively. Growth and sustaining capital amounts presented in the table above are presented net of related contributions in aid of construction costs.

(2) Growth capital projects either (a) result in new sources of cash flow due to enhancements of or additions to existing assets (e.g., additional revenue streams, cost savings resulting from debottlenecking of a facility, etc.) or (b) expand our asset base through construction of new facilities that will generate additional revenue streams and cash flows.

(3) Sustaining capital expenditures are capital expenditures (as defined by GAAP) resulting from improvements to existing assets. Such expenditures serve to maintain existing operations but do not generate additional revenues or result in significant cost savings.

Our most significant growth capital expenditures for the year ended December 31, 2013 involved projects in the Eagle Ford Shale, at our Mont Belvieu complex, to expand joint venture crude oil pipelines and for the ATEX Express pipeline.

We currently expect total capital spending for 2014 to be in the range of $3.9 billion to $4.4 billion, which includes $350 million for sustaining capital expenditures. Our forecast of capital spending for 2014 is based on our announced strategic operating and growth plans (through the filing date of this annual report), which are dependent upon our ability to generate the required funds from either operating cash flows or other means, including borrowings under debt agreements and the issuance of additional equity and debt securities. We may revise our forecast of capital spending due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast of capital spending may change as a result of decisions made by management at a later date, which may include the addition of costs in connection with unforeseen acquisition opportunities.

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

At December 31, 2013, we had approximately $1.14 billion in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to the ATEX Express pipeline and construction projects in Texas and the Rocky Mountains.

During the year ended December 31, 2013, we placed approximately $2.3 billion of major capital projects into service. We expect to complete construction and begin commercial operations related to growth capital spending representing approximately $5.0 billion of investment during 2014. These projects include our:

- ATEX Express pipeline, which commenced operations in January 2014;
- Mid-America Pipeline System expansion project in the Rocky Mountains, which commenced operations in January 2014;
- Front Range Pipeline, which commenced operations in February 2014;
- Seaway Pipeline looping project (expected completion in second quarter of 2014);
- ECHO terminal expansion project (Phase II expected completion in second quarter of 2014);
- refined products export terminal (expected completion in third quarter of 2014);
- SEKCO crude oil pipeline (expected completion in third quarter of 2014); and
- Aegis Ethane Pipeline (portions expected to be completed in third quarter of 2014).

Critical Accounting Policies and Estimates

In our financial reporting processes, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of our financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses for each reporting period. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect. The following describes the estimation risk currently underlying our most significant financial statement items:

Depreciation Methods and Estimated Useful Lives of Property, Plant and Equipment

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of an asset. Our estimate of depreciation expense incorporates management assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts prospectively. Examples of such circumstances include (i) changes in laws and regulations that limit the estimated economic life of an asset, (ii) changes in technology that render an asset obsolete, (iii) changes in expected salvage values, or (iv) significant changes in the forecast life of proved reserves of applicable resource basins, if any.

At December 31, 2013 and 2012, the net carrying value of our property, plant and equipment was $26.95 billion and $24.85 billion, respectively. We recorded $1.01 billion, $900.5 million and $776.6 million in depreciation expense for the years ended December 31, 2013, 2012 and 2011, respectively. For additional information regarding our property, plant and equipment, see Note 8 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Measuring Recoverability of Long-Lived Assets and Fair Value of Equity Method Investments

Long-lived assets, which include property, plant and equipment and intangible assets with finite useful lives, are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes might be production declines that are not replaced by new discoveries or long-term decreases in the demand or price of natural gas, NGLs, crude oil or refined products. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the asset. Estimates of undiscounted cash flows are based on a number of assumptions including anticipated operating margins and volumes; estimated useful life of the asset or asset group; and estimated salvage values. If the carrying value of a long-lived asset is not recoverable, an impairment charge would be recorded for the excess of a long-lived asset's carrying value over its estimated fair value, which is derived from an analysis of the asset's estimated future cash flows, the market value of similar assets and replacement cost of the asset less any applicable depreciation or amortization. In addition, fair value estimates also include usage of probabilities for a range of possible outcomes.

An equity method investment is evaluated for impairment whenever events or changes in circumstances indicate that there is a possible permanent loss in value of the investment (i.e., other than a temporary decline). Examples of such events include sustained operating losses of the investee or long-term negative changes in the investee's industry. When evidence of a loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. We assess the fair value of our equity method investments using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party sales and discounted estimated cash flow models. Estimates of discounted cash flows are based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment's underlying assets.

A significant change in the assumptions we use to measure recoverability of long-lived assets and fair value of equity method investments could result in our recording a non-cash impairment charge. Any such write-down of the value of such assets would increase operating costs and expenses at that time.

During 2013, 2012 and 2011, we recognized non-cash asset impairment charges related to long-lived assets of $92.6 million, $63.4 million and $27.8 million, respectively, which are a component of operating costs and expenses. For additional information regarding these impairment charges, see Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

During 2013, we evaluated our equity method investment in Neptune for impairment. As a result of this evaluation, we recorded a $4.8 million non-cash impairment charge that is a component of equity in earnings from unconsolidated affiliates for the year ended December 31, 2013. There were no impairment charges in 2012 and 2011 related to our equity method investments. For additional information regarding our equity method investments, see Note 9 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Amortization Methods and Estimated Useful Lives of Qualifying Intangible Assets

The specific, identifiable intangible assets of a business depend largely upon the nature of its operations. Potential identifiable intangible assets include items such as intellectual property, customer contracts and relationships, and non-compete agreements. The method used to value each intangible asset will vary depending upon a number of factors, including the nature of the asset and the economic returns it is generating or is expected to generate.

Customer relationship intangible assets represent the estimated economic value we assigned to information about customers and the ability to have regular contact with them as a result of business combinations and assets purchases. These relationships may arise from formal contractual arrangements or through routine contact by sales or service representatives. The value we assign to customer relationships is amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the associated oil and natural gas resource basins from which the customers produce are estimated to be depleted. Our estimate of the useful life of each resource basin is predicated on a number of factors, including reserve estimates and the economic viability of production and exploration activities.

Our contract-based intangible assets represent rights we own arising from discrete contractual agreements, such as the long-term rights we possess under the Shell natural gas processing agreement and the Jonah natural gas transportation contracts. A contract-based intangible asset with a finite life is amortized over its estimated useful life (or term), which is the period over which the asset is expected to contribute directly or indirectly to our cash flows. Our estimates of useful life are based on a number of factors, including (i) the expected useful life of the related tangible assets (e.g., a fractionation facility, pipeline or other asset), (ii) any legal or regulatory developments that would impact such contractual rights, and (iii) any contractual provisions that enable us to renew or extend such agreements.

If our assumptions regarding the estimated useful life of an intangible asset were to change, then the amortization period for such asset would be adjusted accordingly. Changes in the estimated useful life of an intangible asset would impact operating costs and expenses prospectively from the date of change. If we determine that an intangible asset's unamortized cost is not recoverable due to impairment, we would be required to reduce the asset's carrying value to its estimated fair value. Any such write-down of the value of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2013 and 2012, the carrying value of our intangible asset portfolio was $1.46 billion and $1.57 billion, respectively. We recorded $105.6 million, $125.7 million and $147.0 million in amortization expense associated with our intangible assets for the years ended December 31, 2013, 2012 and 2011, respectively. For additional information regarding our intangible assets, see Note 10 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Methods We Employ to Measure the Fair Value of Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing at the end of each fiscal year, and more frequently, if circumstances indicate it is probable that the fair value of goodwill is below its carrying amount. Goodwill impairment testing involves determining the fair value of the associated reporting unit. These fair value amounts are based on assumptions regarding the future economic prospects of the businesses that make up the reporting unit. Such assumptions include (i) discrete financial forecasts for the businesses contained within the reporting unit, which rely on management's estimates of operating margins, throughput volumes and similar factors; (ii) long-term growth rates for cash flows beyond the discrete forecast period; and (iii) appropriate discount rates.

If the fair value of a reporting unit (including its inherent goodwill) is less than its carrying value, a charge to operating costs and expenses is required to reduce the carrying value of the goodwill to its implied fair value. Based on our most recent goodwill impairment test, the estimated fair value of each of our reporting units was substantially in excess of its carrying value (i.e., by at least 10%).

At December 31, 2013 and 2012, the carrying value of our goodwill was $2.08 billion and $2.09 billion, respectively. We did not record any goodwill impairment charges in 2013, 2012 or 2011. For additional information regarding our goodwill, see Note 10 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Revenue Recognition Policies and Use of Estimates for Revenues and Expenses

In general, we recognize revenue from customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists; (ii) delivery has occurred or services have been rendered; (iii) the buyer's price is fixed or determinable; and (iv) collectibility is reasonably assured. We record revenue when sales contracts are settled (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed). We record any necessary allowance for doubtful accounts as required by our established policy. For additional information regarding our revenue recognition policies, see Note 4 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Our use of estimates for certain revenues and expenses has increased as a result of SEC regulations that require us to submit financial information on accelerated time frames. Such estimates are necessary due to the time required to compile actual billing information and receive third party data needed to record transactions for financial reporting purposes. One example of our use of estimates is the accrual of an estimate of processing plant revenue and the cost of natural gas for a given month (prior to receiving actual customer and vendor-related plant operating information for a specific period). These estimates reverse in the following month and are offset by the corresponding actual customer billing and vendor-invoiced amounts. Accordingly, we include one month of certain estimated data in our results of operations. Such estimates are generally based on actual volume and price data through the first part of the month and estimated for the remainder of the month.

Changes in facts and circumstances may result in revised estimates and could affect our reported financial statements and accompanying disclosures. If the assumptions underlying our revenue and expense estimates prove to be substantially incorrect, it could result in material adjustments in results of operations between periods. We review our estimates based on currently available information.

Other Items

Use of Non-GAAP Financial Measure

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

	For the Year Ended December 31,		
	2013	2012	2011
NGL Pipelines & Services	$ 2,514.4	$ 2,468.5	$ 2,184.2
Onshore Natural Gas Pipelines & Services	789.0	775.5	675.3
Onshore Crude Oil Pipelines & Services	742.7	387.7	234.0
Offshore Pipeline & Services	146.1	173.0	228.2
Petrochemical & Refined Products Services	625.9	579.9	535.2
Other Investments (1)	--	2.4	14.8
Total segment gross operating margin	$ 4,818.1	$ 4,387.0	$ 3,871.7

(1) Represents the equity earnings we recorded from our previously held investment in Energy Transfer Equity. Our reporting for this segment ceased on January 18, 2012 when we stopped using the equity method to account for this investment. See Note 9 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for additional information regarding the liquidation of our investment in Energy Transfer Equity.

The following table presents a reconciliation of non-GAAP total segment gross operating margin to GAAP operating income and further to income before income taxes for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2013	2012	2011
Total segment gross operating margin	$ 4,818.1	$ 4,387.0	$ 3,871.7
Adjustments to reconcile total segment gross operating margin to operating income:			
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(1,148.9)	(1,061.7)	(958.7)
Subtract impairment charges not reflected in gross operating margin	(92.6)	(63.4)	(27.8)
Subtract operating lease expenses paid by EPCO not reflected in gross operating margin	--	--	(0.3)
Add gains and subtract losses attributable to asset sales and insurance recoveries not reflected in gross operating margin	83.4	17.6	156.0
Subtract non-refundable deferred revenues included in gross operating margin attributable to shipper make-up rights on new pipeline projects	(4.4)	--	--
Subtract general and administrative costs not reflected in gross operating margin	(188.3)	(170.3)	(181.8)
Operating income	3,467.3	3,109.2	2,859.1
Other expense, net	(802.7)	(698.4)	(743.6)
Income before income taxes	$ 2,664.6	$ 2,410.8	$ 2,115.5

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our executive management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income.

In total, gross operating margin represents operating income exclusive of (1) depreciation, amortization and accretion expenses, (2) impairment charges, (3) gains and losses attributable to asset sales and insurance recoveries and (4) general and administrative costs. As discussed below, gross operating margin includes equity in income of unconsolidated affiliates and non-refundable deferred transportation revenues relating to the make-up rights of committed shippers associated with certain pipelines. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in consolidation. Gross operating margin is exclusive of other income and expense transactions, income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before any allocation of earnings to noncontrolling interests.

We include equity in income of unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Equity investments with industry partners are a significant component of our business strategy. They are a means by which we conduct our operations to align our interests with those of customers and/or suppliers. This method of operation enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed. Many of these businesses perform supporting or complementary roles to our other midstream business operations.

Management includes deferred transportation revenues relating to the make-up rights of committed shippers when reviewing the financial results of certain major new pipeline projects such as the Texas Express Pipeline and Seaway Pipeline. Certain shippers on these systems did not meet their minimum volume commitment beginning in the fourth quarter of 2013, thus revenues associated with each shipper’s make-up rights were deferred in accordance with GAAP. From an internal (and segment) reporting standpoint, management considers the transportation fees paid by committed shippers on major new pipeline projects, including any non-refundable revenues that may be deferred under GAAP related to make-up rights, to be important in assessing the financial performance of these pipeline assets. From a GAAP perspective, the revenue streams associated with these make-up rights are deferred until the earlier of (i) the deficiency volumes are shipped, (ii) the contractual make-up period expires or (iii) the pipeline is otherwise released from its performance obligation. Since management includes these deferred revenues in non-GAAP gross operating margin, these amounts are deducted in determining GAAP-based operating income. Our consolidated revenues do not reflect any deferred revenues until the conditions for recognizing such revenues are met in accordance with GAAP.

Management expects that several of our new pipeline projects, including the ATEX Express pipeline, Texas Express Pipeline and Front Range Pipeline, will experience periods where shippers are unable to meet their contractual minimum volume commitments during 2014. We anticipate that committed shipper transportation volumes on ATEX Express may be negatively impacted by producer drilling programs, including the timing of new production well start-ups in the Marcellus and Utica Shale developments. With respect to the Texas Express Pipeline and Front Range Pipeline, we expect that ethane rejection in the supply basins served by these pipelines will adversely impact shipper transportation volumes.

Insurance Matters

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other insurance coverage, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance may not fully cover every type of damage, interruption or other loss that might occur. If we were to incur a significant loss for which we were not fully insured, it could have a material impact on our financial position, results of operations and cash flows.

In addition, there may be timing differences between amounts we accrue related to property damage expense, amounts we are required to pay in connection with a loss and amounts we subsequently receive from insurance carriers as reimbursements. Any event that materially interrupts the revenues generated by our consolidated operations, or other losses that require us to make material expenditures not reimbursed by insurance, could reduce our ability to pay distributions to our unitholders and, accordingly, adversely affect the market price of our common units.

Involuntary conversions result from the loss of an asset because of some unforeseen event (e.g., destruction due to fire). Some of these events are insurable, thus resulting in a property damage insurance recovery. Amounts we receive from insurance carriers are net of any deductibles related to the covered event. EPCO's deductibles currently range from $5.0 million to $60.0 million depending on the nature of the loss (windstorm or non-windstorm) and the assets involved (onshore or offshore).

We received $15.0 million, $30.0 million and $20.0 million of nonrefundable insurance proceeds during the years ended December 31, 2013, 2012 and 2011, respectively, attributable to property damage claims we filed in connection with a February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. Operating income for the years ended December 31, 2013, 2012 and 2011 includes $15.0 million, $30.0 million and $4.7 million of gains, respectively, related to these insurance recoveries. The remaining West Storage claims of approximately $95.0 million are anticipated to be collected during the first quarter of 2014. To the extent that additional non-refundable cash insurance proceeds related to this incident are received, we expect to record gains equal to such proceeds.

Due to the high cost of windstorm insurance coverage for our offshore Gulf of Mexico assets, we elected to self-insure these assets during the annual policy period extending from June 2012 to June 2013. We continue to self-insure these assets for the current annual policy period, which extends from June 2013 to June 2014.

For additional information regarding insurance matters, see Note 18 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Table of Contents

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2013 (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 debt obligations (1)	$ 17,357.7	$ 1,125.0	$ 2,050.0	$ 1,150.0	$ 13,032.7
Estimated cash payments for interest (2)	$ 18,092.0	$ 860.9	$ 1,569.2	$ 1,463.5	$ 14,198.4
Operating lease obligations (3)	$ 332.8	$ 42.4	$ 79.4	$ 66.1	$ 144.9
Purchase obligations: (4)					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas	$ 4,372.0	$ 1,088.9	$ 1,759.9	$ 944.0	$ 579.2
NGLs	$ 2,147.1	$ 1,917.7	$ 229.4	$ --	$ --
Crude oil	$ 1,159.5	$ 1,159.5	$ --	$ --	$ --
Petrochemicals and refined products	$ 3,943.6	$ 2,058.0	$ 1,817.2	$ 68.4	$ --
Other	$ 117.0	$ 80.0	$ 15.1	$ 10.3	$ 11.6
Underlying major volume commitments:					
Natural gas (in TBtus)	1,143	282	456	256	149
NGLs (in MMBbls)	42	38	4	--	--
Crude oil (in MMBbls)	12	12	--	--	--
Petrochemicals and refined products (in MMBbls)	42	22	19	1	--
Service payment commitments (5)	$ 1,030.9	$ 201.4	$ 380.4	$ 241.2	$ 207.9
Capital expenditure commitments (6)	$ 1,137.5	$ 1,137.5	$ --	$ --	$ --
Other long-term liabilities (7)	$ 172.3	$ --	$ 11.4	$ 8.1	$ 152.8
Total	$ 49,862.4	$ 9,671.3	$ 7,912.0	$ 3,951.6	$ 28,327.5

(1) Represents scheduled future maturities of our consolidated debt principal obligations. For information regarding our consolidated debt obligations, see Note 11 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

(2) Estimated cash payments for interest are based on the principal amount of our consolidated debt obligations outstanding at December 31, 2013, the contractually scheduled maturities of such balances, and the applicable fixed or variable interest rates paid during 2013. With respect to our variable-rate debt obligations, we applied the weighted-average interest rate paid during 2013 to determine the estimated cash payments. See Note 11 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for the weighted-average variable interest rate charged in 2013 under our revolving credit facility. In addition, our estimate of cash payments for interest gives effect to interest rate swap agreements that were in place at December 31, 2013. See Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for information regarding these derivative instruments. Our estimated cash payments for interest are significantly influenced by the long-term maturities of our junior subordinated notes (due August 2066 through January 2068). Our estimated cash payments for interest with respect to each junior subordinated note are based on the current fixed interest rate for each note applied to the entire remaining term through the respective maturity date.

(3) Primarily represents leases of underground salt dome caverns for the storage of natural gas and NGLs, office space with affiliates of EPCO and land held pursuant to right-of-way agreements.

(4) Represents enforceable and legally binding agreements to purchase goods or services as of December 31, 2013. The estimated payment obligations are based on contractual prices in effect at December 31, 2013 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery.

(5) Primarily represents our unconditional payment obligations under firm pipeline transportation contracts.

(6) Represents unconditional payment obligations for services to be rendered or products to be delivered in connection with our capital spending program, including our share of the capital spending of our unconsolidated affiliates.

(7) As reflected on our consolidated balance sheet at December 31, 2013, other long-term liabilities primarily represent the noncurrent portion of asset retirement obligations and deferred revenues.

For additional information regarding our significant contractual obligations, see Note 17 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that have or are reasonably expected to have a material current or future effect on our financial position, results of operations and cash flows.

Related Party Transactions

For information regarding our related party transactions, see Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Regulation

For information regarding the impact of federal, state or local regulatory measures on our business, see "Regulatory Matters" included under Part I, Item 1 and 2 of this annual report.

Recent Accounting Developments

The Financial Accounting Standards Board ("FASB") and the International Accounting Standards Board ("IASB") continue their joint project to converge U.S. GAAP and International Financial Reporting Standards in the area of revenue recognition. As currently drafted, the converged standard eliminates the transaction- and industry-specific revenue recognition guidance under current U.S. GAAP and replaces it with a principles based approach for determining revenue recognition. It is expected that the new standard will be issued during the first quarter of 2014. Although the FASB and IASB continue their deliberations on certain revenue recognition topics, we continue to monitor developments in connection with the proposed new accounting guidance. Based on information currently available, the effective date of the new standard would be January 1, 2017.

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

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with certain anticipated future transactions, we use derivative instruments such as futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

We assess the risk associated with each of our derivative instrument portfolios using a sensitivity analysis model. This approach measures the change in fair value of the derivative instrument portfolio based on a hypothetical 10% change in the underlying interest rates or quoted market prices on a particular day. In addition to these variables, the fair value of each portfolio is influenced by changes in the notional amounts of the instruments outstanding and the discount rates used to determine the present values. The sensitivity analysis approach does not reflect the impact that the same hypothetical price movement would have on the hedged exposures to which they relate. Therefore, the impact on the fair value of a derivative instrument resulting from a change in interest rates or quoted market prices (as applicable) would normally be offset by a corresponding gain or loss on the hedged debt instrument, inventory value or forecasted transaction assuming:

§ the derivative instrument functions effectively as a hedge of the underlying risk;

§ the derivative instrument is not closed out in advance of its expected term; and

§ the hedged forecasted transaction occurs within the expected time period.

We routinely review the effectiveness of our derivative instrument portfolios in light of current market conditions. Accordingly, the nature and volume of our derivative instruments may change depending on the specific exposure being managed.

See Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for additional information regarding our derivative instruments and hedging activities.

Interest Rate Hedging Activities

We may utilize interest rate swaps, forward starting swaps and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy is a component in controlling our overall cost of capital associated with such borrowings. The composition of our derivative instrument portfolios may change from period-to-period depending on our hedging requirements.

With respect to the tabular data below, each portfolio's estimated fair value at a given date is based on a number of factors, including the number and types of derivatives outstanding at that date, the notional value of the swaps and associated interest rates.

Interest rate swaps

Interest rate swaps exchange the stated interest rate paid on a notional amount of existing debt for the fixed or floating interest rate stipulated in the derivative instrument. The following table summarizes our portfolio of interest rate swaps at December 31, 2013 (dollars in millions):

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes AA	10 fixed-to-floating swaps	$ 750.0	1/2011 to 2/2016	3.2% to 1.2%	Fair value hedge
Undesignated swaps	6 floating-to-fixed swaps	$ 600.0	5/2010 to 7/2014	0.2% to 2.0%	Mark-to-market

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value ("FV") of our interest rate swap portfolio at the dates indicated (dollars in millions):

		Interest Rate Swap Portfolio Aggregate Fair Value at		
Scenario	Resulting Classification	December 31, 2012	December 31, 2013	January 31, 2014
FV assuming no change in underlying interest rates	*Asset*	$ 28.0	$ 24.8	$ 28.3
FV assuming 10% increase in underlying interest rates	*Asset*	27.2	24.1	27.7
FV assuming 10% decrease in underlying interest rates	*Asset*	28.8	25.5	28.9

Forward-starting interest rate swaps

Forward starting swaps perform a similar function as traditional interest rate swaps except that they are associated with interest rates underlying anticipated future issuances of debt. The 16 forward starting swaps outstanding at December 31, 2012 with an aggregate notional value of $1.0 billion were settled at a loss of $168.8 million in March 2013 in connection with the issuance of Senior Notes HH and II. There were no forward starting swaps outstanding at December 31, 2013.

Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, refined products and petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps, basis swaps and option contracts.

The following table summarizes our portfolio of commodity derivative instruments outstanding at December 31, 2013 (volume measures as noted):

Derivative Purpose	Volume (1) Current (2)	Long-Term (2)	Accounting Treatment
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	7.0	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls)	1.1	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	0.4	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	3.1	0.1	Cash flow hedge
Natural gas marketing:			
Forecasted sales of natural gas (Bcf)	2.6	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	8.2	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	5.9	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	5.4	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.6	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.6	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	0.1	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	4.0	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	5.8	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	94.7	19.7	Mark-to-market
Refined products risk management activities (MMBbls) (4)	0.8	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	14.4	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is January 2015, May 2014 and October 2016, respectively.
(3) Current volumes include 27.5 Bcf of physical derivative instruments that are predominantly priced at a marked-based index plus a premium or minus a discount related to location differences.
(4) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

As of January 31, 2014, our predominant commodity hedging strategies consisted of (i) hedging anticipated future purchases and sales of commodity products associated with transportation, storage and blending activities, (ii) hedging the fair value of commodity products held in inventory, (iii) hedging natural gas processing margins, and (iv) hedging octane enhancement margins. The following information summarizes these hedging strategies:

§ The objective of our anticipated future commodity purchases and sales hedging program is to hedge the margins of certain transportation, storage and blending activities by locking in purchases and sales prices through the use of forward contracts and derivative instruments.

§ The objective of our inventory hedging program is to hedge the fair value of commodity products currently held in inventory by locking in the sales price of the inventory through the use of forward contracts and derivative instruments.

§ The objective of our natural gas processing hedging program is to hedge an amount of gross margin associated with these activities. We achieve this objective by executing forward fixed-price sales of a portion of our expected equity NGL production using forward contracts and commodity derivative instruments. For certain natural gas processing contracts, the hedging of expected equity NGL production also involves the purchase of natural gas for plant thermal reduction, which is hedged by executing forward fixed-price purchases using forward contracts and derivative instruments.

§ The objective of our octane enhancement hedging program is to hedge an amount of gross margin associated with these activities. We achieve this objective by executing forward fixed-price sales of a portion of our expected octane enhancement product volumes and forward fixed-price purchases of NGL feedstocks using forward contracts and derivative instruments.

Certain basis swaps, basis spread options and other derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of commodity products. There is some uncertainty involved in the timing of these transactions often due to the development of more favorable profit opportunities or when spreads are insufficient to cover variable costs thus reducing the likelihood that the transactions will occur during the periods originally forecasted. In accordance with derivatives accounting guidance, these instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of the underlying assets. Due to volatility in commodity prices, any non-cash, mark-to-market earnings variability cannot be predicted.

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

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2012**	**December 31, 2013**	**January 31, 2014**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ 7.6	$ (1.3)	$ (1.5)
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	3.0	(6.7)	(4.5)
FV assuming 10% decrease in underlying commodity prices	*Asset*	12.2	4.1	1.6

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our NGL marketing, refined products marketing and octane enhancement portfolios at the dates indicated (dollars in millions):

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2012**	**December 31, 2013**	**January 31, 2014**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ 10.5	$ (20.7)	$ 9.5
FV assuming 10% increase in underlying commodity prices	*Liability*	(27.5)	(69.8)	(28.1)
FV assuming 10% decrease in underlying commodity prices	*Asset*	48.5	28.5	47.0

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

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2012**	**December 31, 2013**	**January 31, 2014**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (2.0)	$ 8.2	$ 10.9
FV assuming 10% increase in underlying commodity prices	*Liability*	(10.0)	(9.8)	(2.0)
FV assuming 10% decrease in underlying commodity prices	*Asset*	6.1	26.1	23.9

Product Purchase Commitments

We have long and short-term purchase commitments for natural gas, NGLs, crude oil, petrochemicals and refined products. 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 Note 17 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Item 8. ***Financial Statements and Supplementary Data***

Our audited consolidated financial statements begin on page F-1 of this annual report.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*.**

None.

Item 9A. ***Controls and Procedures*.**

Disclosure Controls and Procedures

As of the end of the period covered by this annual report, our management carried out an evaluation, with the participation of our general partner's chief executive officer, Michael A. Creel (our principal executive officer), and chief financial officer, W. Randall Fowler (our principal financial officer), of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based on this evaluation, as of the end of the period covered by this annual report, Mr. Creel and Mr. Fowler concluded:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our principal executive and financial officers, as appropriate to allow for timely decisions regarding required disclosures; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fourth quarter of 2013, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Certifications

The required certifications of Mr. Creel and Mr. Fowler under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 are included as exhibits to this annual report (see Exhibits 31 and 32 included under Part IV, Item 15 of this annual report).

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL
OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2013

The management of Enterprise Products Partners L.P. and its consolidated subsidiaries, including its chief executive officer and chief financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal control system was designed to provide reasonable assurance to the management of Enterprise Products Partners L.P. and the Board of Directors of its general partner regarding the preparation and fair presentation of Enterprise Products Partners L.P.'s published financial statements.

Our management assessed the effectiveness of Enterprise Products Partners L.P.'s internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in *Internal Control—Integrated Framework (1992)*. 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, 2013, Enterprise Products Partners L.P.'s internal control over financial reporting is effective based on those criteria.

Our Audit and Conflicts Committee is comprised of independent directors who are not officers or employees of our general partner. This committee meets regularly with members of management, internal audit staff and representatives of Deloitte & Touche LLP, which is our independent registered public accounting firm, to discuss the adequacy of Enterprise Products Partners L.P.'s internal controls over financial reporting, consolidated financial statements and the nature, extent and results of the audit effort. Management reviews all of Enterprise Products Partners L.P.'s significant accounting policies and assumptions affecting its results of operations with the Audit and Conflicts Committee. Both the independent registered public accounting firm and our internal auditors have direct access to the Audit and Conflicts Committee without the presence of management.

Deloitte & Touche LLP has issued its attestation report regarding our internal control over financial reporting. That report is included within this Item 9A (see "Report of Independent Registered Public Accounting Firm").

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 their respective capacities indicated below on March 3, 2014.

/s/ *Michael A. Creel*	/s/ *W. Randall Fowler*
Name: Michael A. Creel	Name: W. Randall Fowler
Title: Chief Executive Officer of our general partner, Enterprise Products Holdings LLC	Title: Chief Financial Officer of our general partner, Enterprise Products Holdings LLC

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products Holdings LLC and the
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

We have audited the internal control over financial reporting of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2013, based on criteria established in *Internal Control — Integrated Framework (1992)* 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, 2013. 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, 2013, based on the criteria established in *Internal Control—Integrated Framework (1992)* 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, 2013 of the Company and our report dated March 3, 2014 expresses an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 3, 2014

Item 9B. *Other Information*.

None.

PART III

Item 10. *Directors, Executive Officers and Partnership Governance*.

Partnership Management

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for our management, administrative or operating functions. Pursuant to the ASA, these roles are performed by employees of EPCO, which are under the direction of the Board of Directors (the "Board") and executive officers of Enterprise GP. For a description of the ASA, see "Relationship with EPCO and Affiliates—EPCO ASA" under Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

The executive officers of Enterprise GP are elected for one-year terms and may be removed, with or without cause, only by the Board. Our unitholders do not elect the officers or directors of Enterprise GP. The DD LLC Trustees, through their control of Enterprise GP, have the ability to elect, remove and replace at any time, all of the officers and directors of our general partner. Each member of the Board of Enterprise GP serves until such member's death, resignation or removal. The employees of EPCO who served as directors of our general partner during 2013 were Ms. Williams and Messrs. Bachmann, Creel, Cunningham, Fowler and Teague.

Notwithstanding any contractual limitation on its obligations or duties, Enterprise GP is liable for all debts we incur (to the extent not paid by us), except to the extent that such indebtedness or other obligations are non-recourse to Enterprise GP. Whenever possible, Enterprise GP intends to make any such indebtedness or other obligations non-recourse to itself.

Under our limited partnership agreement and subject to specified limitations, we will indemnify to the fullest extent permitted by Delaware law, from and against all losses, claims, damages or similar events, any director or officer, or while serving as director or officer, any person who is or was serving as a tax matters member or as a director, officer, tax matters member, employee, partner, manager, fiduciary or trustee of our partnership or any of our affiliates. Additionally, we will indemnify to the fullest extent permitted by law, from and against all losses, claims, damages or similar events, any person who is or was an employee (other than an officer) or agent of our general partner.

On February 19, 2013, the Board of Enterprise GP re-elected Mr. Creel as CEO and Mr. Teague as Chief Operating Officer ("COO") and elected Ms. Williams as Chairman of the Board. The Board also approved the creation of a new management oversight group, known as the Office of the Chairman, which consists of the Chairman of the Board, CEO and COO.

In his role as CEO, Mr. Creel remains our principal executive officer and is responsible for, among other things: (i) managing the overall business and financial strategy of Enterprise; (ii) overseeing and providing strategic direction for our businesses, subject to Board approval, in the areas of finance, accounting, human resources, investor relations, risk management and information technology; and (iii) providing required certifications as principal executive officer of Enterprise regarding disclosure controls and procedures and internal control over financial reporting. In his role as COO, Mr. Teague is responsible for, among other things, managing the day-to-day operations of Enterprise and overseeing and providing strategic direction for our businesses, subject to Board approval, in the areas of operations, business development, health and safety. Each of the roles of CEO and COO report directly to the Board. In her role as Chairman of the Board (a non-executive role), Ms. Williams is responsible for, among other things: (i) presiding over and setting the agendas for meetings of the Board, with due consideration for the values and business goals of Enterprise and an effective governance structure; (ii) overseeing the appropriate flow of information to the Board; (iii) acting as a liaison between the Board and senior management;

and (iv) meeting regularly with the CEO and COO and other Board members to review the strategic direction of Enterprise.

The purpose of the Office of the Chairman is for the group to serve collectively as a liaison to the Board and senior management with respect to, and to provide the Chairman, CEO and COO a venue to discuss, certain matters including: (i) our strategic direction (including business opportunities through organic growth and acquisitions); (ii) the vision, leadership and development of the management team; (iii) business goals and operational performance; and (iv) strategies to preserve our financial strength. In addition, the Office of the Chairman will assist the Board and its Governance Committee in identifying director education opportunities and in determining the size and composition of the Board and recruitment of new members. The Office of the Chairman will also oversee policies that (i) reflect Enterprise's values and business goals and (ii) enhance the effectiveness of our governance structure.

Partnership 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 of strong governance is having independent members of the Board. Pursuant to the NYSE listing standards, a director will be considered independent if the Board determines that he or she does not have a material relationship with Enterprise GP or us (either directly or as a partner, unitholder or officer of an organization that has a material relationship with Enterprise GP or us). Based on the foregoing, the Board has affirmatively determined that Messrs. Andress, Barnett, Casey, McMahen, Ross, Smith and Snell are independent directors under the NYSE rules.

Because we are a limited partnership and meet the definition of a "controlled company" under the listing standards of the NYSE, we are not required to comply with certain NYSE rules. In particular, we are not required to comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board of our general partner be comprised of a majority of independent directors. Currently, seven of the thirteen Board members of Enterprise GP are independent under NYSE rules; however, this composition may not always be in effect. Also, we have elected to not comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board of Enterprise GP maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Code of Conduct and Ethics and Corporate Governance Guidelines

Enterprise GP has adopted a "Code of Conduct" that applies to its directors, officers and employees. This code sets forth our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance on complying with the code, the reporting of compliance issues, and discipline for violations of the code. The Code of Conduct also establishes policies applicable to our CEO, chief financial officer ("CFO"), principal accounting officer and senior financial and other managers to prevent wrongdoing and to promote honest and ethical conduct, including ethical handling of actual and apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications, and prompt internal reporting of violations of the code (and thus accountability for adherence to the code). Employees are required to periodically certify their understanding and compliance with the Code of Conduct.

Governance guidelines, together with applicable committee charters, provide the framework for effective governance of our partnership. The Board has adopted the "Governance Guidelines of Enterprise Products Partners," which address several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibilities of the Audit and Conflicts Committee and the Governance Committee, the conduct and frequency of Board and committee meetings, management succession plans, director access to management and outside advisors, director compensation, director and executive officer equity ownership, director orientation and continuing education, and annual self-evaluation of the Board. The Board recognizes that effective governance is an on-going process, and thus, it will review the Governance Guidelines of Enterprise Products Partners annually or more often as deemed necessary.

Audit and Conflicts Committee

The purpose of the Board's Audit and Conflicts Committee (or "Audit Committee") is to address audit and conflicts-related matters. In accordance with NYSE rules and the Securities Exchange Act of 1934, the Board has named three of its members to serve on the Audit Committee. Members of the Audit Committee must have a basic understanding of finance and accounting matters and be able to read and understand fundamental financial statements, and at least one member of the Audit Committee shall have accounting or related financial management expertise. The current members of the Audit Committee are Messrs. McMahen (chairman), Ross and Snell, all of whom are independent directors, free from any relationship with us or any of our subsidiaries that would interfere with the exercise of independent judgment. The Board has affirmatively determined that Mr. McMahen satisfies the definition of "audit committee financial expert" as defined in Item 407(d) of Regulation S-K promulgated by the SEC.

The primary responsibilities of the Audit Committee include (i) reviewing potential conflicts of interest, including related party transactions, (ii) monitoring the integrity of our financial reporting process and related systems of internal control, (iii) ensuring our legal and regulatory compliance and that of Enterprise GP, (iv) overseeing the independence and performance of our independent public accountant, (v) approving all services performed by our independent public accountant, (vi) providing for an avenue of communication among the independent public accountant, management, internal audit function and the Board, (vii) encouraging adherence to and continuous improvement of our policies, procedures and practices at all levels, (viii) reviewing areas of potential significant financial risk to our businesses and (ix) approving awards granted under long-term incentive plans.

If the Board believes that a particular matter presents a conflict of interest and proposes a resolution, the Audit Committee has the authority to review such matter to determine if the proposed resolution is fair and reasonable to us. Any matters approved by the Audit Committee are conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by Enterprise GP or the Board of any duties they may owe us or our unitholders.

Pursuant to its formal written charter, the Audit Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. The Audit Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

Governance Committee

The primary purpose of the Governance Committee is to develop and recommend to the Board a set of governance guidelines applicable to our partnership, to review such guidelines from time to time and to oversee governance matters related to our business, including Board and Committee composition, qualifications of Board candidates, director independence, succession planning and related matters. The Governance Committee also assists in Board oversight of management's establishment and administration of our environmental, health and safety policies, procedures, programs and initiatives, and related matters. In accordance with its charter, the Governance Committee shall be composed of not less than three members, at least a majority of whom shall be independent directors. Currently, the Governance Committee is comprised of four independent directors: Messrs. Andress, Barnett (chairman), Casey and Smith.

Like the Audit Committee, the Governance Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. In addition, the Governance Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

Investor Access to Corporate Governance Information

We provide investors access to information relating to our governance procedures and principles, including the Code of Conduct, Governance Guidelines, the Audit and Governance Committee charters, along with other information, through our website, www.enterpriseproducts.com. You may also contact our Investor Relations department at (866) 230-0745 for printed copies of these documents free of charge.

NYSE Corporate Governance Listing Standards

On March 8, 2013, Mr. Creel, our CEO, certified to the NYSE (as required by Section 303A.12(a) of the NYSE Listed Company Manual) that he was not aware of any violation by us of the NYSE's Corporate Governance listing standards as of March 8, 2013.

Executive Sessions of Non-Management Directors

The Board holds regular executive sessions in which non-management directors meet without any members of management present. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, one director is designated as the "presiding director," who is responsible for leading and facilitating such executive sessions. Currently, the presiding director is Mr. McMahen.

In accordance with NYSE rules, we have established a toll-free, confidential telephone hotline (the "Hotline") so that interested parties may communicate with the presiding director or with all the non-management directors as a group. All calls to this Hotline are reported to the chairman of the Audit Committee, who is responsible for communicating any necessary information to the other non-management directors. The number of our confidential Hotline is (877) 888-0002.

Directors and Executive Officers of Enterprise GP

The following table sets forth the name, age and position of each of the directors and executive officers of Enterprise GP at March 3, 2014. Each executive officer holds the same respective office shown below in the managing member of EPO.

Name	Age	Position with Enterprise GP
Randa Duncan Williams	52	Director and Chairman of the Board
Thurmon M. Andress (1)	80	Director
Richard H. Bachmann	61	Director
E. William Barnett (1,2)	81	Director
Larry J. Casey (1)	81	Director
Michael A. Creel (3)	60	Director and CEO
Dr. Ralph S. Cunningham	73	Director
W. Randall Fowler (3)	57	Director, Executive Vice President and CFO
Charles E. McMahen (4,5)	74	Director
Rex C. Ross (4)	70	Director
Edwin E. Smith (1)	82	Director
Richard S. Snell (4)	71	Director
A. James Teague (3)	68	Director and COO
Graham W. Bacon (3)	50	Group Senior Vice President
William Ordemann (3)	54	Group Senior Vice President
Michael C. Smith (3)	42	Group Senior Vice President
Bryan F. Bulawa (3)	44	Senior Vice President and Treasurer
Stephanie C. Hildebrandt (3)	49	Senior Vice President, General Counsel and Secretary
Michael J. Knesek (3)	59	Senior Vice President, Controller and Principal Accounting Officer

(1) Member of the Governance Committee
(2) Chairman of the Governance Committee
(3) Executive officer
(4) Member of the Audit Committee
(5) Chairman of the Audit Committee

In addition to the persons listed above, Mr. O.S. Andras serves as an honorary director of Enterprise GP. Mr. Andras' role is solely honorary and does not confer any of the rights, obligations, liabilities or responsibilities of a director of Enterprise GP (including any power or authority to vote on any matters as a director).

The following information presents a brief history of the business experience of our directors and executive officers of Enterprise GP:

Randa Duncan Williams. Ms. Williams was elected as Chairman of the Board of Directors of Enterprise GP in February 2013 and as a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). She served as a director of Holdings GP from May 2007 to November 2010. She was elected Chairman of EPCO in May 2010, having previously served as Group Co-Chairman since 1994. Ms. Williams has served as a director of EPCO since February 1991. Prior to joining EPCO, Ms. Williams practiced law with the firms Butler & Binion and Brown, Sims, Wise & White. Ms. Williams previously served on the board of directors of Encore Bancshares from July 2007 until July 2012. She currently serves on the board of trustees for numerous charitable organizations. Ms. Williams is the daughter of the late Mr. Dan L. Duncan, our founder.

Thurmon M. Andress. Mr. Andress was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and serves on its Governance Committee. He served as a director of Holdings GP from November 2006 to November 2010. Mr. Andress serves as the Managing Director-Houston for Breitburn Energy Company L.P. and is a former member of its Board of Directors. In 1990, he founded Andress Oil & Gas Company, serving as its President and CEO until it merged with Breitburn Energy Company L.P. in 1998. In 1982, he founded Bayou Resources, Inc. a publicly traded energy company that was sold in 1987. From 2002 through December 2009, Mr. Andress served as a member of the Board of Directors of Edge Petroleum Corp. (including its Governance and Compensation Committees). In October 2009, Edge Petroleum Corp. filed a voluntary petition under Chapter 11 of the U.S. Bankruptcy Code and, on December 31, 2009, completed the sale of substantially all of its assets to Mariner Energy, Inc. Mr. Andress is currently a member of the National Petroleum

Council and the Natural Gas Committee. He also serves on the Board of Governors of Houston for the Independent Petroleum Association of America. In 1993, Mr. Andress was inducted into All American Wildcatter's, a 100-member organization dedicated to American oil and gas explorationists and producers.

Richard H. Bachmann. Mr. Bachmann was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). He served as an Executive Vice President of Holdings GP from April 2005 to November 2010 and as a director of Holdings GP from February 2006 to November 2010. He served as Chief Legal Officer and Secretary of Holdings GP from April 2005 to May 2010. Mr. Bachmann served as Executive Vice President and Chief Legal Officer of EPGP from February 1999 until November 2010 and as Secretary of EPGP from November 1999 to November 2010. He previously served as a director of EPGP from June 2000 to January 2004 and from February 2006 to May 2010.

Mr. Bachmann was elected President and CEO of EPCO in May 2010 and has served as a director since January 1999. He previously served as Secretary of EPCO from May 1999 to May 2010 and as a Group Vice Chairman of EPCO from December 2007 to May 2010. Mr. Bachmann served as a director of DEP GP from October 2006 to May 2010 and as President and CEO of DEP GP from October 2006 to April 2010. In November 2006, Mr. Bachmann was appointed as an independent manager of Constellation Energy Partners LLC. Mr. Bachmann also serves as a member of the Audit, Compensation and Nominating and Governance Committees of Constellation Energy Partners LLC and as the Chairman of its Conflicts Committee.

E. William Barnett. Mr. Barnett was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and serves as Chairman of its Governance Committee. He served as a director of EPGP from March 2005 to November 2010. Mr. Barnett practiced law with Baker Botts L.L.P. from 1958 until his retirement in 2004. In 1984, he became Managing Partner of Baker Botts L.L.P. and continued in that role for 14 years until 1998. He was Senior Counsel to the firm from 1998 until June 2004, when he retired from the firm. Mr. Barnett served as Chairman of the Board of Trustees of Rice University from 1996 to July 2005.

Mr. Barnett is a Life Trustee of The University of Texas Law School Foundation and a Trustee Emeritus and former Chairman of the Houston Zoo, Inc. (the operating arm of the Houston Zoo); and a Director Emeritus of Baylor College of Medicine. From June 2006 until May 2013, he served as a director of Westlake Chemical Corporation (a publicly traded chemical company). From October 2002 until May 2012, Mr. Barnett served as a director of GenOn Energy, Inc. (a publicly traded wholesale electricity generation company) and its predecessors. 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.

Larry J. Casey. Mr. Casey was elected a director of Enterprise GP in September 2011 and serves on its Governance Committee. He previously served as a director of DEP GP from October 2006 until September 2011. Mr. Casey has been a private investor managing real estate and personal investments since he retired in 1982 from a career in the energy industry. In 1974, Mr. Casey founded Xcel Products Company, an NGL and petrochemical trading company. Also in 1974, he founded Xral Underground Storage, the first privately owned underground merchant storage facility for NGLs and specialty chemicals at Mont Belvieu, Texas. Mr. Casey sold these companies in 1982.

Michael A. Creel. Mr. Creel was elected CEO and a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and served as President of Enterprise GP from November 2010 until February 2013. He served as a director of EPGP from February 2006 to November 2010 and President and CEO of EPGP from August 2007 to November 2010. Mr. Creel served as CFO of EPGP from June 2000 to August 2007, and as an Executive Vice President of EPGP from January 2001 to August 2007. Mr. Creel, a Certified Public Accountant, also served as a Senior Vice President of EPGP from November 1999 to January 2001.

Mr. Creel previously served as a director of Holdings GP from October 2009 to May 2010 and as a director of DEP GP from October 2006 to May 2010. He previously served as President, CEO and a director of Holdings GP from August 2005 through August 2007. From October 2006 to August 2007, he served as Executive Vice President and CFO of DEP GP. From October 2005 through December 2009, Mr. Creel served as a director of Edge Petroleum Corporation, a publicly traded oil and natural gas exploration and production company, which filed a voluntary petition under Chapter 11 of the U.S. Bankruptcy Code in October 2009 and, on December 31, 2009, completed the sale of substantially all of its assets to Mariner Energy, Inc.

Dr. Ralph S. Cunningham. Dr. Cunningham was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and served as Chairman of the Board of Enterprise GP from November 2010 until February 2013. Dr. Cunningham served as a director and as the President and CEO of Holdings GP from August 2007 until November 2010. He served as a director of EPGP from February 2006 to May 2010, having previously served as a director of EPGP from April 1998 until March 2005. In addition to these duties, Dr. Cunningham served as Group Executive Vice President and COO of EPGP from December 2005 to August 2007 and Interim President and Interim CEO from June 2007 to August 2007. Dr. Cunningham served as a director of DEP GP from August 2007 to May 2010. He served as Chairman and a director of TEPPCO's general partner from March 2005 until November 2005.

Dr. Cunningham was elected Vice Chairman of EPCO in May 2010 and a director in March 2006, having previously served as Group Vice Chairman of EPCO from December 2007 to May 2010 and as a director of EPCO from 1987 to 1997. He serves as a director, as Chairman of the Board and as a member of each of the Audit Committee and the Nominating and Corporate Governance Committee of TETRA Technologies, Inc. He also previously served as a director of Agrium, Inc. until April 2013. In addition, Dr. Cunningham serves as a director, as the Chairman of the Safety, Environment and Responsibility Committee and as a member of each of the Human Resources and Compensation Committee and the Nominating and Corporate Governance Committee of Cenovus Energy Inc. Dr. Cunningham retired in 1997 from CITGO Petroleum Corporation, where he served as President and CEO since 1995. Dr. Cunningham also served as a director of LE GP, LLC (the general partner of Energy Transfer Equity, L.P.) from December 2009 to November 2010.

W. Randall Fowler. Mr. Fowler was elected a director of Enterprise GP in September 2011. He was named an Executive Vice President and the CFO of Enterprise GP in November 2010 (upon consummation of the Holdings Merger), having previously served as Executive Vice President and CFO of EPGP from August 2007 to November 2010. He also served as President and CEO of DEP GP from April 2010 until September 2011 and as Executive Vice President and CFO of DEP GP from August 2007 to April 2010. He served as a director of DEP GP from September 2006 until September 2011.

Mr. Fowler served as Senior Vice President and Treasurer of EPGP from February 2005 to August 2007 and of DEP GP from October 2006 to August 2007. Mr. Fowler also previously served as a director of EPGP and of Holdings GP from February 2006 to May 2010. Mr. Fowler also served as Senior Vice President and CFO of Holdings GP from August 2005 to August 2007. Mr. Fowler was elected Vice Chairman and CFO of EPCO in May 2010. He previously served as President and CEO of EPCO from December 2007 to May 2010 and as its CFO from April 2005 to December 2007.

Mr. Fowler, a Certified Public Accountant (inactive), joined us as Director of Investor Relations in January 1999. Mr. Fowler also serves as Chairman of the Board of the National Association of Publicly Traded Partnerships. He also serves on the Advisory Board for the College of Business at Louisiana Tech University.

Charles E. McMahen. Mr. McMahen was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and serves as Chairman of its Audit Committee. He served as a director of Holdings GP from August 2005 to November 2010. Mr. McMahen served as Vice Chairman of Compass Bank from March 1999 until December 2003 and served as Vice Chairman of Compass Bancshares from April 2001 until his retirement in December 2003. Mr. McMahen also served as Chairman and CEO of Compass Banks of Texas from March 1990 until March 1999. Mr. McMahen has served as a director of Compass Bancshares, and its successor, BBVA Compass Bank (a wholly owned subsidiary of BBVA), since 2001. He also serves as a director for BBVA Compass Bancshares, Inc. (a wholly owned subsidiary of BBVA and a bank holding company for BBVA's North American banking operations). Mr. McMahen serves on the Audit Committee for BBVA Compass Bancshares, Inc. and as Chairman of its Risk Committee. Mr. McMahen served as Chairman of the Board of Regents of the University of Houston from September 1998 to August 2000.

Rex C. Ross. Mr. Ross was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and is a member of its Audit Committee. He served as a director of EPGP from October 2006 until November 2010. Until July 2009, Mr. Ross served as a director of Schlumberger Technology Corporation, the holding company for all Schlumberger Limited assets and entities in the U.S. Prior to his retirement from Schlumberger Limited in May 2004, Mr. Ross held a number of executive management positions during his 11-year career with the company, including President of Schlumberger Oilfield Services North America; President, Schlumberger GeoQuest; and President of SchlumbergerSema North & South America. Mr. Ross also serves on the Board of Directors of Gulfmark Offshore, Inc. (a publicly traded offshore marine services company) and is a member of its Audit Committee and its Governance & Nominating Committee.

Edwin E. Smith. Mr. Smith was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and is a member of its Governance Committee. He served as a director of Holdings GP from August 2005 to November 2010. Mr. Smith has been a private investor since he retired from Allied Bank of Texas in 1989 after a 31-year career in banking. Mr. Smith previously served as a director of Encore Bancshares from July 2007 until July 2012 and as a director of EPCO from 1987 until 1997.

Richard S. Snell. Mr. Snell, a Certified Public Accountant, was elected a director of Enterprise GP in September 2011 and serves on its Audit Committee. He previously served as a director of DEP GP from January 2010 until September 2011. Mr. Snell also served as a director of TEPPCO's general partner from January 2006 until October 2009. From June 2000 until February 2006, he served as a director of EPGP. He is senior counsel with the law firm of Thompson & Knight LLP, having been with the firm since 2000. Prior to his position with Thompson & Knight LLP, he worked as an attorney for the Snell & Smith, P.C. law firm from its founding in 1993 until 2000.

A. James Teague. Mr. Teague was elected COO and a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and served as an Executive Vice President of Enterprise GP from November 2010 until February 2013. He served as Executive Vice President of EPGP from November 1999 to November 2010 and additionally as a director from July 2008 to November 2010 and as Chief Operating Officer from September 2010 to November 2010. In addition, he served as EPGP's Chief Commercial Officer from July 2008 until September 2010. He served as Executive Vice President and Chief Commercial Officer of DEP GP from July 2008 until September 2011. He previously served as a director of DEP GP from July 2008 to May 2010 and as a director of Holdings GP from October 2009 to May 2010. Mr. Teague joined Enterprise in connection with its purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. From 1998 to 1999, Mr. Teague served as President of Tejas Natural Gas Liquids, LLC, then an affiliate of Shell. From 1997 to 1998, he was President of Marketing and Trading for Mapco Inc.

Graham W. Bacon. Mr. Bacon was elected as Group Senior Vice President, Operations and Environmental, Health, Safety & Training in February 2014. He previously served as a Senior Vice President, Operations from January 2012 to February 2014, as a Vice President, Operations from June 2006 to January 2012, and as a Vice President, Engineering from September 2005 to May 2006. He joined Enterprise in 1991 and has held a variety of operations and engineering roles. Prior to joining Enterprise, Mr. Bacon worked for Vista Chemical Company.

William Ordemann. Mr. Ordemann was elected a Group Senior Vice President in April 2012 and is responsible for Enterprise's onshore and offshore natural gas and crude oil pipelines, natural gas processing and storage assets, as well as NGL fractionation and storage facilities. He previously served as Executive Vice President of Holdings GP from August 2007 to November 2010 and as Executive Vice President of Enterprise GP from November 2010 to April 2012. He also served as COO of EPGP from August 2007 until September 2010 and as its Executive Vice President from August 2007 to November 2010. He was also elected an Executive Vice President of DEP GP in August 2007 and served in such role until September 2011. He previously served as a Senior Vice President of EPGP from September 2001 to August 2007 and was a Vice President of EPGP from October 1999 to September 2001. Mr. Ordemann joined Enterprise in connection with our purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. Prior to joining Enterprise, he was a Vice President of Shell Midstream Enterprises, LLC from January 1997 to February 1998, and Vice President of Tejas Natural Gas Liquids, LLC from February 1998 to September 1999.

Michael C. Smith. Mr. Smith was elected a Group Senior Vice President in January 2014 and is responsible for Enterprise's regulated businesses. He previously served as Senior Vice President, Unregulated NGL

Business from April 2012 to January 2014, as Vice President, Western Gas Gathering & Processing from January 2010 to April 2012, as Vice President, Rocky Mountain Gathering from January 2009 to December 2009, as Director, Rocky Mountains, January 2006 to January 2009, and as Director, Commercial Development from October 2002 to December 2005. Prior to joining Enterprise, Mr. Smith served in marketing, engineering, and project management roles with Mapco Inc. and The Williams Companies.

Bryan F. Bulawa. Mr. Bulawa was elected a Senior Vice President and the Treasurer of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). He previously served as Senior Vice President, CFO and Treasurer of DEP GP from April 2010 until September 2011 and a director of DEP GP from February 2011 to September 2011. He also served as Senior Vice President and Treasurer of EPGP and Holdings GP from October 2009 to November 2010, as Senior Vice President and Treasurer of DEP GP from October 2009 to April 2010, and as Vice President and Treasurer of EPGP from July 2007 to October 2009. He has also served as Senior Vice President and Treasurer of EPCO since May 2010. Prior to joining Enterprise, Mr. Bulawa spent 13 years at Scotia Capital, where he last served as director of the firm's U.S. Energy Corporate Finance and Distribution group.

Stephanie C. Hildebrandt. Ms. Hildebrandt was elected a Senior Vice President and the General Counsel of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and served as Senior Vice President and General Counsel of EPGP and Holdings GP from May 2010 to November 2010. Ms. Hildebrandt served as Senior Vice President, Chief Legal Officer and Secretary of DEP GP from April 2010 until September 2011, having previously served as Vice President and General Counsel of EPGP from October 2009 to May 2010, as Vice President and Deputy General Counsel of EPGP from 2006 to 2009, and as Deputy General Counsel of EPGP from 2004 to 2006. Prior to joining us, Ms. Hildebrandt practiced law for three years at El Paso Corporation and for 12 years at Texaco Inc.

Michael J. Knesek. Mr. Knesek, a Certified Public Accountant, was elected the Senior Vice President, Controller and Principal Accounting Officer of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). From February 2005 to November 2010, Mr. Knesek served as Senior Vice President of EPGP, having previously served as a Vice President of EPGP since August 2000. Mr. Knesek served as the Principal Accounting Officer and Controller of Holdings GP from August 2005 to November 2010 and served in the same capacity for DEP GP from September 2006 to September 2011. He served as the Principal Accounting Officer and Controller of EPGP from August 2000 to November 2010. He also served as Senior Vice President of DEP GP from September 2006 to September 2011. Mr. Knesek has been the Controller of EPCO since 1990 and currently serves as one of its Senior Vice Presidents.

Director Experience, Qualifications, Attributes and Skills

The following is a brief discussion of the experience, qualifications, attributes or skills that led to the conclusion that each of the following persons should serve as a director of our general partner.

Six of our directors are current employees of EPCO and officers of our general partner or its affiliates. Each of these directors has significant experience in our industry as executive officers as well as other qualifications, attributes and skills. These include: for Ms. Williams, legal and community involvement with numerous charitable organizations, and active involvement in EPCO's businesses, including ownership and management of Enterprise's businesses; for Dr. Cunningham, over 45 years of refined products, chemicals and midstream businesses; for Mr. Bachmann, over 30 years of experience with our midstream assets, including legal, regulatory, contracts and mergers and acquisitions and, for over the last ten years, as a member of Enterprise's executive management team; for Mr. Creel, over 30 years of management experience with midstream assets, for both third parties and Enterprise, including finance and accounting (certified public accountant) and more than seven years of management experience in the financial industry; for Mr. Fowler, over ten years of experience with our midstream assets, including finance, accounting (inactive certified public accountant) and investor public relations and, for over the last seven years, as a member of our executive management team; and for Mr. Teague, over 40 years of commercial management of midstream assets and marketing and trading activities, both for third parties and for Enterprise's businesses.

Our seven outside directors also have significant experience in our industry in a variety of capacities, as well as other qualifications, attributes and skills. These include: for Mr. Andress, oil and gas exploration and production; for Mr. Barnett, legal, regulatory and management skills as a former managing partner of an international law firm; for Mr. Casey, executive management of NGL and petrochemicals trading, and related storage businesses; for Mr. McMahen, banking and finance; for Mr. Ross, executive management of oilfield services businesses; for Mr. Smith, banking and investments; and for Mr. Snell, legal and accounting matters and previous board service for other publicly traded midstream partnerships.

Section 16(a) Beneficial Ownership Reporting Compliance

Under federal securities laws, directors and executive officers of Enterprise GP and any persons holding more than 10% of our common units are required to report their beneficial ownership of common units and any changes in their beneficial ownership levels to us and the SEC. Specific due dates for these reports have been established by regulation, and we are required to disclose in this annual report any failure to file this information within the specified timeframes. All such reporting was done in a timely manner in 2013, except that a grant of restricted common units for which Mr. Knesek is the beneficial owner was reported on a Form 4 filed on March 6, 2013, instead of by the reporting deadline in February 2013.

Item 11. *Executive Compensation*.

Executive Officer Compensation

We do not directly employ any of the persons responsible for managing our business. Instead, we are managed by our general partner, the executive officers of which are employees of EPCO. Our management, administrative and operating functions are primarily performed by employees of EPCO pursuant to the ASA. Pursuant to the ASA, we reimburse EPCO for 100% of its compensation costs related to employment of personnel working on our behalf. For information regarding the ASA, see Note 14 of the Notes to Consolidated Financial Statements included under Part II, 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, 2013, 2012 and 2011 for the CEO, the CFO, and the three other most highly compensated executive officers of our general partner. Collectively, these individuals were our "named executive officers" for 2013.

Name and Principal Position	Year	Cash Salary ($)	Cash Bonus ($) (1)	Unit Awards ($) (2)	Option Awards ($)	All Other Comp. ($) (3)	Total ($)
Michael A. Creel	2013	$ 775,000	$ 1,750,000	$ 4,123,342	$ --	$ 575,115	$ 7,223,457
(CEO)	2012	769,000	1,550,000	3,738,240	--	597,606	6,654,846
	2011	707,275	1,425,000	2,640,354	--	530,461	5,303,090
W. Randall Fowler	2013	418,144	562,500	2,141,625	--	302,824	3,425,093
(Executive Vice President and CFO)	2012	415,097	562,500	1,947,000	--	312,216	3,236,813
	2011	402,905	562,500	1,442,100	--	287,595	2,695,100
A. James Teague	2013	690,150	1,750,000	4,123,342	--	489,233	7,052,725
(COO)	2012	685,150	1,550,000	3,364,416	--	459,763	6,059,329
	2011	665,113	1,300,000	1,922,800	--	412,067	4,299,980
William Ordemann	2013	425,150	400,000	1,142,200	--	234,962	2,202,312
(Group Senior Vice President)	2012	422,900	300,000	1,038,400	--	294,486	2,055,786
	2011	414,612	250,000	1,311,000	--	329,170	2,304,782
Stephanie C. Hildebrandt	2013	375,000	250,000	1,142,200	--	181,598	1,948,798
(Senior Vice President, General Counsel	2012	368,750	250,000	1,038,400	--	169,183	1,826,333
and Secretary)	2011	309,504	250,000	1,145,900	--	116,210	1,821,614

(1) Amounts represent discretionary annual cash awards accrued with respect to the years presented. Cash awards are paid in February of the following year (e.g., the cash awards with respect to 2013 were paid in February 2014).

(2) Amounts represent our estimated share of the aggregate grant date fair value of restricted common unit awards granted during each year presented. For information about assumptions made in the valuation of these awards and limited partner interests, see Note 5 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report, the applicable disclosures of which are incorporated by reference into this Item 11.

(3) Amounts include (i) contributions in connection with funded, qualified, defined contribution retirement plans, (ii) quarterly distributions paid on incentive plan awards, (iii) the imputed value of life insurance premiums paid on behalf of the officer and (iv) other amounts. See the following table for additional information.

The following table presents the components of "All Other Compensation" for each named executive officer for the year ended December 31, 2013:

	Contributions Under Funded, Qualified, Defined Contribution Retirement Plans	Quarterly Distributions Paid On Incentive Plan Awards	Life Insurance Premiums	Other	Total All Other Compensation
Michael A. Creel	$ 28,050	$ 536,660	$ 3,564	$ 6,841	$ 575,115
W. Randall Fowler	21,037	274,665	1,742	5,380	302,824
A. James Teague	28,050	450,122	6,858	4,203	489,233
William Ordemann	30,600	198,342	1,242	4,778	234,962
Stephanie C. Hildebrandt	28,050	148,725	810	4,013	181,598

Certain of the named executive officers perform services for other affiliates of EPCO. Under the ASA, the compensation costs of our named executive officers, including those related to equity-based awards, are allocated between us and other affiliates of EPCO 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.

The following table presents the average approximate amount of time devoted by each of our named executive officers to our consolidated businesses and to EPCO and its other affiliates during each of the years presented.

Named Executive Officer	Year	Enterprise Products Partners	EPCO and other affiliates	Total Time Allocated
Michael A. Creel (CEO)	2013	100%	--	100%
	2012	100%	--	100%
	2011	95%	5%	100%
W. Randall Fowler (CFO)	2013	75%	25%	100%
	2012	75%	25%	100%
	2011	75%	25%	100%
A. James Teague	2013	100%	--	100%
	2012	100%	--	100%
	2011	100%	--	100%
William Ordemann	2013	100%	--	100%
	2012	100%	--	100%
	2011	100%	--	100%
Stephanie C. Hildebrandt	2013	100%	--	100%
	2012	100%	--	100%
	2011	100%	--	100%

Compensation Discussion and Analysis

With respect to our named executive officers, compensation paid or awarded by us for the last three fiscal years reflects only that portion of compensation paid by EPCO and allocated to us pursuant to the ASA, including an allocation of a portion of the cost of equity-based long-term incentive plans of EPCO. The EPCO Trustees control EPCO and provide recommendations with respect to the compensation of our CEO and COO. As described further below, the Audit Committee of our general partner has ultimate decision-making authority with respect to compensation for each of our CEO and COO, and our CEO and COO have ultimate decision-making authority with respect to compensation for our other named executive officers. The following elements of compensation, and EPCO's decisions with respect to determination of payments, are not subject to approvals by the Board or the Audit Committee of our general partner, except in the case of compensation paid to each of our CEO and COO (as described below). Neither EPCO nor our general partner has a separate compensation committee; however, equity awards granted under EPCO's long-term incentive plans to officers of our general partner (including our named executive officers) are approved by the Audit Committee.

As discussed below, the elements of EPCO's compensation program, along with EPCO's other incentives (e.g., benefits, work environment and career development), are intended to provide a total rewards package to employees. The objectives of EPCO's compensation program are to provide competitive compensation opportunities that will align and drive employee performance toward the creation of sustained long-term unitholder value. Our compensation program allows us to attract, motivate and retain high quality talent with the skills and competencies we require. The compensation package is designed to reward contributions by employees in support of the business strategies of EPCO and its affiliates at both our partnership and individual levels. With respect to the three years ended December 31, 2013, 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, 2013, the elements of compensation for the named executive officers consisted of annual cash base salary, discretionary annual cash bonus awards, awards under long-term incentive arrangements and other compensation, including very limited perquisites.

In order to assist our CEO, EPCO and the Audit Committee with compensation decisions, EPCO's senior vice president of Human Resources formulates preliminary compensation recommendations for each of the named executive officers, including our CEO and COO. With respect to compensation to be paid to each of our CEO and COO, the EPCO Trustees consider such preliminary recommendation and make revisions, if appropriate. Afterwards, EPCO's senior vice president of Human Resources presents the revised compensation recommendations for each of our CEO and COO to the members of the Audit Committee, which consider the recommendations and then make a final determination regarding compensation of each of our CEO and COO. In making their final determination, the Audit Committee may discuss the recommendations with EPCO's senior vice president of Human Resources, request to discuss the recommendations with EPCO's compensation consultant, and/or retain its own compensation consultant.

With respect to compensation to be paid to the remaining named executive officers other than our CEO and COO, the CEO and COO consider the preliminary recommendations of EPCO's senior vice president of Human Resources and make revisions, if appropriate. The CEO and COO make a final determination regarding compensation of these 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. In 2013, EPCO engaged Meridian Compensation Partners, LLC (the "Consultant") to complete a detailed review of executive compensation relative to our industry. In connection with this review, the Consultant provided comparative market data on compensation practices and programs for executive level positions based on an analysis of industry competitors and other large companies. The market data for industry competitors included information from Anadarko Petroleum Corporation; CenterPoint Energy, Inc.; CMS Energy Corporation; Dominion Resources, Inc.; Enbridge Energy Partners, L.P.; Energy Transfer Partners, L.P.; Kinder Morgan Inc.; NiSource Inc.; ONEOK, Inc.; Plains All American Pipeline, L.P.; Spectra Energy Corp.; Sunoco Logistics Partners;

The Williams Companies, Inc.; and TransCanada Corporation. The market data for other large companies included 75 entities across multiple industries, including well-known companies such as Merck & Co., Inc.; The Home Depot, Inc.; Caterpillar Inc.; Target Corporation; and Honeywell International Inc., among others.

Neither we, nor EPCO, which engages the Consultant, are aware of the specific data of the companies included in the Consultant's proprietary database for specific positions. EPCO uses the information provided in the Consultant's analysis to gauge whether compensation levels reported by the Consultant and the general ranges of compensation for EPCO employees in similar positions are comparable, but that comparison is only a factor taken into consideration and may or may not impact compensation of our named executive officers, for which our Audit Committee (in the case of our CEO's and COO's compensation) or our CEO and COO (in the case of compensation to be paid to our other named executive officers) have the ultimate decision-making authority. EPCO does not otherwise engage in benchmarking for the named executive officers' positions.

The Audit Committee, our CEO, our COO and EPCO do not use any formula or specific performance-based criteria in determining the compensation of our named executive officers for services they perform for us; rather, the Audit Committee or our CEO and COO (as applicable) and EPCO determine an appropriate level and mix of compensation on a case-by-case basis. Further, there is no established policy or target for the allocation between either cash and non-cash or short-term and long-term incentive compensation. However, some considerations that the Audit Committee or our CEO and COO (as applicable) may take into account in making the case-by-case compensation determinations include total value of all elements of compensation and the appropriate balance of internal pay equity among executive officers. The Audit Committee, our CEO, our COO and EPCO also consider individual performance, levels of responsibility and value to the organization. All compensation determinations are subjective and discretionary and, as noted above, subject to the ultimate decision-making authority of the Audit Committee or our CEO and COO (as applicable), except for equity awards under EPCO's long-term incentive plans, as discussed below.

We believe that the absence of specific performance-based criteria associated with our cash compensation and equity awards, and the long-term nature of our equity awards, has the effect of discouraging excessive risk taking by our executive officers in order to reach certain targets. Further, the practice of making compensation decisions on a case-by-case basis permits consideration of flexible criteria, including current overall market conditions.

Changes in the base salaries of our named executive officers during the three years ending December 31, 2013 were largely budget-driven and made consistent relative to increases in the base salaries of our other executive officers.

The discretionary cash bonus awards paid to each of our named executive officers were determined by consultation, as appropriate, among the EPCO Trustees, our CEO, our COO and EPCO's senior vice president of Human Resources, subject to final determination by the Audit Committee (in the case of our CEO's and COO's cash bonus awards) and our CEO and COO (in the case of cash bonus awards to be paid to our other named executive officers). These cash bonus awards, in combination with annual base salaries, are intended to yield competitive total cash compensation levels for the named executive officers and drive performance in support of our business strategies, as well as the performance of other EPCO affiliates for which the named executive officers may perform services. It is EPCO's general policy to pay these awards in February of the following year. The discretionary cash bonuses reflected the Audit Committee's (with respect to our CEO and COO) and our CEO's and COO's (with respect to the other named executive officers) general consideration of our financial performance for those periods, without any weight or formula given to any specific financial performance measures, as well as their subjective judgment of each named executive officer's general contributions in connection with our performance, again without any weight or formula given to any specific individual contribution or accomplishments. The levels of cash bonuses were also based on the level and position of such named executive officers and the relative compensation paid to our other executive officers.

Awards granted to our named executive officers under EPCO's long-term incentive plans were determined by consultation among the EPCO Trustees, our CEO, our COO and EPCO's senior vice president of Human Resources, and were approved by the Audit Committee. The levels of EPCO's long-term incentive plan awards to our named executive officers during the last three years also reflected the Audit Committee's (with respect to our

CEO and COO) and our CEO's and COO's (with respect to the other named executive officers) general consideration of our financial performance for those periods, without any weight or formula given to any specific financial performance measures, as well as their subjective judgment of each named executive officer's general contributions in connection with our performance, again without any weight or formula given to any specific individual contribution or accomplishments. The levels of long-term incentive awards were also based on the level and position of such named executive officers and the relative compensation paid to our other executive officers.

EPCO expects to continue its policy of paying for limited perquisites attributable to our named executive officers. EPCO also makes matching contributions under its defined contribution plans for the benefit of our named executive officers in the same manner as it does for other EPCO employees.

EPCO does not offer our named executive officers a defined benefit pension plan. Also, none of our named executive officers had nonqualified deferred compensation during the three years ended December 31, 2013.

In the fourth quarter of 2010, EPCO entered into retention agreements with each of Messrs. Creel, Fowler, Teague and Ordemann to reinforce and encourage the continued dedication of such officers to EPCO and us as a member of our executive management team and to assure that we and EPCO will have the services of these executives in the foreseeable future. Pursuant to the retention agreements, Messrs. Creel, Fowler, Teague and Ordemann will be entitled to a cash retention payment of $10 million, $5 million, $10 million and $2.5 million, respectively, less applicable tax withholdings (as applicable to each person, the "Retention Payment") following the completion of 48 months of continuous employment with EPCO from the effective date of each retention agreement (the "Retention Period"). We record an allocated portion of such costs based on the approximate amount of time each officer spends on our consolidated business activities. The effective date of the retention agreements for Mr. Creel, Mr. Fowler and Mr. Teague was December 1, 2010. The effective date of the retention agreement for Mr. Ordemann was October 1, 2010.

Notwithstanding the required Retention Period, if at any time between 24 months and 48 months after December 1, 2010 (i.e., the period of continuous employment from December 1, 2010 until such time being referred to as the "Performance Period"), Mr. Teague designates a candidate to serve as COO of Enterprise GP and such candidate is determined by the Audit Committee to be satisfactory and is hired by EPCO, then Mr. Teague will be entitled to a cash performance payment of the greater of (a) $6 million or (b) $10 million times (i) the number of months of Mr. Teague's Performance Period, divided by (ii) 48 (the "Performance Payment"). Pursuant to his retention agreement, Mr. Teague is eligible to earn and receive either the Performance Payment or the Retention Payment, but not both.

Notwithstanding the Retention Period described above, each of Messrs. Creel, Fowler, Teague and Ordemann will receive, or in the event of his death, his designated beneficiary will receive, unless otherwise required by law, his applicable Retention Payment in the event of an involuntary termination of his employment prior to the end of his Retention Period for specified reasons, including death, disability or termination of his employment by EPCO other than for "cause" (as defined in the applicable retention agreement) in connection with his job elimination, a business reorganization, or a sale of EPCO or us. The Retention Payment is payable in full within 30 days of such qualifying termination. In the event Mr. Creel, Mr. Fowler, Mr. Teague or Mr. Ordemann is paid his Retention Payment in connection with an involuntary termination as described above, he agrees that, for a period equal to the lesser of (i) 18 months after the date of the event which gives rise to the Retention Payment or (ii) the remainder of the Retention Period (as if the retention agreement were in full force and effect for the full Retention Period), he will not solicit or induce, either directly or indirectly, any of our employees to cease employment with EPCO.

Any Retention Payment or Performance Payment (with respect to Mr. Teague) is in addition to any discretionary incentive compensation that EPCO or any of its affiliates may, in its sole discretion, grant or have in place from time to time.

Although the retention agreements, restricted common unit awards and unit option awards are entered into with EPCO, all or a portion of the compensation related to these agreements may be allocated to us in accordance with the ASA by and among EPCO, us and the other parties thereto.

We believe that each of the base salary, discretionary cash bonus awards, long-term incentive awards and retention agreements, as applicable, fit the overall compensation objectives of us and of EPCO and are designed to avoid risks that are likely to conflict with our risk management policies.

Grants of Plan-Based Awards in Fiscal Year 2013

The following table presents information concerning each 2013 grant of a plan-based award to a named executive officer for which we will be allocated our pro rata share of the related expense under the ASA.

		Estimated Future Payouts Under Equity Incentive Plan Awards			Exercise or Base Price of Option	Grant Date Fair Value of Unit and Option
Name	**Grant Date**	**Threshold (#)**	**Target (#)**	**Maximum (#)**	**Awards ($/Unit)**	**Awards ($)** (1)
Restricted common unit awards:						
Michael A. Creel (CEO)	2/19/13	--	72,200	--	--	$ 4,123,342
W. Randall Fowler (CFO)	2/19/13	--	50,000	--	--	2,141,625
A. James Teague	2/19/13	--	72,200	--	--	4,123,342
William Ordemann	2/19/13	--	20,000	--	--	1,142,200
Stephanie C. Hildebrandt	2/19/13	--	20,000	--	--	1,142,200

(1) Amounts presented reflect that portion of grant date fair value allocable to us based on the average percentage of time each named executive officer spent on our consolidated businesses during 2013. Based on current allocations, we estimate that the consolidated compensation expense we record for each named executive officer with respect to these awards will approximate these grant date fair value amounts over the vesting period. The closing price of our common units on February 19, 2013 was $57.11 per unit.

The restricted common unit awards granted to the named executive officers during 2013 were made under the 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) (“2008 Plan”). This plan provides for incentive awards to EPCO’s key employees and non-employee directors and consultants who perform management, administrative or operational functions for us or our affiliates.

No option awards were granted during 2013.

Grant date fair value amounts presented in the preceding table are based on certain assumptions and considerations made by management. See Note 5 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for additional information regarding our fair value assumptions made in connection with equity-based compensation.

Summary of Long-Term Incentive Arrangements Underlying 2013 Award Grants

Awards granted under the 2008 Plan may be in the form of unit options, restricted common units, phantom units, unit appreciation rights (“UARs”), distribution equivalent rights (“DERs”) and other unit-based awards or substitute awards. As of December 31, 2013, no phantom unit awards, UARs or associated DERs have been granted under EPCO’s incentive compensation plans to the named executive officers.

Restricted common unit awards allow recipients to acquire our common units (at no cost to the recipient apart from service or other conditions) once a defined vesting period expires, subject to customary forfeiture provisions. Restricted common unit grants generally vest at a rate of 25% per year beginning one year after the grant date. The fair value of restricted common units is based on the market price per unit of our common units on the date of grant. For financial statement purposes, compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures. Each recipient is also entitled to quarterly cash distributions equal to the product of the number of restricted common units outstanding for the participant and the quarterly cash distribution per common unit paid by us.

Equity Awards Outstanding at December 31, 2013

The following information summarizes each named executive officer's long-term incentive awards outstanding at December 31, 2013.

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 common unit awards:							
Michael A. Creel (CEO)	Various (1)	--	--	--	--	178,250	$ 11,817,975
W. Randall Fowler (CFO)	Various (1)	--	--	--	--	122,250	8,105,175
A. James Teague	Various (1)	--	--	--	--	156,050	10,346,115
William Ordemann	Various (1)	--	--	--	--	58,450	3,875,235
Stephanie C. Hildebrandt	Various (1)	--	--	--	--	50,875	3,373,013
Unit option awards:							
Michael A. Creel (CEO):							
February 19, 2009 option grant (4)	2/19/13	--	75,000	$ 22.06	12/31/14	--	--
May 6, 2009 option grant (4)	5/06/13	--	90,000	24.92	12/31/14	--	--
February 23, 2010 option grant (5)	2/23/14	--	90,000	32.27	12/31/15	--	--
W. Randall Fowler (CFO):							
February 19, 2009 option grant (4)	2/19/13	--	52,500	22.06	12/31/14	--	--
May 6, 2009 option grant (4)	5/06/13	--	60,000	24.92	12/31/14	--	--
February 23, 2010 option grant (5)	2/23/14	--	60,000	32.27	12/31/15	--	--
A. James Teague:							
February 19, 2009 option grant (4)	2/19/13	--	60,000	22.06	12/31/14	--	--
May 6, 2009 option grant (4)	5/06/13	--	60,000	24.92	12/31/14	--	--
February 23, 2010 option grant (5)	2/23/14	--	60,000	32.27	12/31/15	--	--
William Ordemann:							
February 19, 2009 option grant (4)	2/19/13	--	45,000	22.06	12/31/14	--	--
May 6, 2009 option grant (4)	5/06/13	--	60,000	24.92	12/31/14	--	--
February 23, 2010 option grant (5)	2/23/14	--	60,000	32.27	12/31/15	--	--
Stephanie C. Hildebrandt:							
February 19, 2009 option grant (4)	2/19/13	--	7,500	22.06	12/31/14	--	--
May 6, 2009 option grant (4)	5/06/13	--	15,000	24.92	12/31/14	--	--
February 23, 2010 option grant (5)	2/23/14	--	15,000	32.27	12/31/15	--	--

(1) Of the 565,875 non-vested restricted common unit awards presented in the table, 228,775 vest in 2014, 163,200 vest in 2015, 115,300 vest in 2016 and 58,600 vest in 2017.
(2) Amounts represent the total number of restricted common unit awards outstanding for each named executive officer.
(3) Amounts derived by multiplying the total number of restricted common unit awards outstanding for each named executive officer by the closing price of our common units at December 31, 2013 (the last trading day of 2013) of $66.30 per unit.
(4) These option grants were exercised in February 2014.
(5) These option grants are exercisable beginning in February 2015.

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options. These unit option awards are denominated in our common units. When issued, the exercise price of each unit option award may be no less than the market price of our common units on the date of grant. In general, unit option awards have a vesting period of four years from the date of grant and expire at the end of the calendar year following the year of vesting (e.g., an option vesting on February 19, 2013 will expire on December 31, 2014). However, unit option awards only become exercisable at certain times during the calendar year (typically the months of February, May, August and November) following the year in which they vest.

Option Exercises and Units Vested

The following table presents the exercise of unit options by and vesting of restricted common units to our named executive officers during the year ended December 31, 2013. These amounts are presented on a gross basis and do not reflect any allocation of compensation to other entities under the ASA.

Name	Option Awards: Number of Units Acquired on Exercise (#) (1)	Option Awards: Value Realized on Exercise ($) (2)	Unit Awards: Number of Units Acquired on Vesting (#) (1)	Unit Awards: Value Realized on Vesting ($) (3)
Michael A. Creel (CEO):				
Option awards	40,652	$ 2,293,200		
Restricted common unit awards			104,750	$ 5,080,274
W. Randall Fowler (CFO):				
Option awards	27,102	1,528,800		
Restricted common unit awards			70,250	3,383,735
A. James Teague:				
Option awards	27,102	1,528,800		
Restricted common unit awards			77,850	3,617,661
William Ordemann:				
Option awards	27,102	1,528,800		
Restricted common unit awards			50,950	2,707,050
Stephanie C. Hildebrandt:				
Option awards	6,775	382,200		
Restricted common unit awards			21,875	773,063

(1) Represents gross number of securities acquired before adjustments for applicable tax withholdings.

(2) Amount determined by multiplying the number of options exercised by the difference between the closing price of our common units on the date of exercise and the exercise price.

(3) Amount determined for restricted common unit awards by multiplying the number of restricted common unit awards that vested during 2013 by the closing price of our common units on the date of vesting.

Potential Payments Upon Termination or Change-in-Control

Our named executive officers do not have any employment agreements that call for payment of termination or severance benefits or provide for any payments in the event of a change in control of our general partner.

EPCO has entered into retention agreements with each of Messrs. Creel, Fowler, Teague and Ordemann, which are described under “Compensation Discussion and Analysis” within this Part III, Item 11. Under these agreements, each such person will receive, or in the event of his death, his designated beneficiary will receive, unless otherwise required by law, his applicable Retention Payment (set forth previously) in the event of an involuntary termination of his employment prior to the end of his Retention Period for specified reasons, including death, disability or termination of his employment by EPCO other than for “cause” (as defined in each retention agreement) in connection with his job elimination, a business reorganization or a sale of EPCO or our partnership.

Vesting of restricted common unit awards and option awards under the Enterprise Products 1998 Long-Term Incentive Plan (“1998 Plan”) and the 2008 Plan are subject to acceleration upon a qualifying termination, including termination after a change of control of our general partner. Qualifying termination under such awards generally means a termination as an employee of EPCO or an affiliated group member (i) upon death, (ii) a qualifying long-term disability, (iii) a qualifying retirement, or (iv) within one year after a change of control (as defined), other than a termination for cause (as defined) or termination by such person that is not a qualifying termination for good reason (as defined). A change of control under these award agreements is generally defined to mean that Dan L. Duncan, his widow, descendants, heirs and/or legatees and/or distributees of Dan L. Duncan’s estate, and/or trusts (including, without limitation, one or more voting trusts) established for the benefit of his widow, descendants, heirs and/or legatees and/or distributees, collectively, cease, directly or indirectly, to control our general partner. Mr. Duncan passed away in March 2010.

As of December 31, 2013, the estimated market value of unvested unit option awards that could be realized in connection with an accelerated vesting for a qualifying termination (calculated as the difference between the exercise prices of the underlying options and the closing price of our common units on December 31, 2013 of $66.30 per unit, but without reflecting any allocation of compensation to other entities under the ASA), would have been the following for each of the named executive officers:

	Accelerated Option Value
Michael A. Creel (CEO)	$ 10,104,900
W. Randall Fowler (CFO)	6,847,200
A. James Teague	7,179,000
William Ordemann	6,515,400
Stephanie C. Hildebrandt	1,462,950

Although the retention agreements, restricted common unit awards and unit option awards are entered into with EPCO, all or an allocated portion of the compensation related to these agreements may be charged to us in accordance with the ASA.

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. As described in Compensation Discussion and Analysis, decisions regarding the compensation of our named executive officers are made, as applicable, by EPCO, our CEO and COO, and the Audit Committee of our general partner.

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, 2013.

Submitted by: Randa Duncan Williams
Thurmon M. Andress
Richard H. Bachmann
E. William Barnett
Larry J. Casey
Michael A. Creel
Dr. Ralph S. Cunningham
W. Randall Fowler
Charles E. McMahen
Rex C. Ross
Edwin E. Smith
Richard S. Snell
A. James Teague

Notwithstanding anything to the contrary set forth in any previous filings under the Securities Act, as amended, or the Securities 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 2013. As previously noted, we do not have a separate compensation committee. As described in Compensation Discussion and Analysis, decisions regarding the compensation of our named executive officers are made, as applicable, by EPCO, our CEO and COO, and the Audit Committee of our general partner.

Director Compensation

Neither we nor our general partner provide any additional compensation to employees of EPCO who serve as directors of our general partner.

The independent directors of our general partner are compensated as follows: (i) each receives a $75,000 annual cash retainer; (ii) if the individual serves as chairman of a committee of the Board, then he receives an additional $15,000 in cash annually; (iii) each receives a meeting fee of $1,500 in cash for each meeting of the Board attended; (iv) each receives 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 (v) each receives an annual grant of our common units having a fair market value, based on the closing price of such security on the trading day immediately preceding the date of grant, of approximately $75,000.

The following table presents information regarding compensation paid to the independent directors of our general partner during the year ended December 31, 2013:

Name	Fees Earned or Paid in Cash ($)	Unit Awards ($)	All Other Compensation ($)	Total ($)
Thurmon M. Andress	$ 87,000	$ 75,842	$ --	$ 162,842
E. William Barnett (1)	102,000	75,842	--	177,842
Larry J. Casey	87,000	75,842	--	162,842
Charles E. McMahen (2)	108,000	75,842	--	183,842
Rex C. Ross	93,000	75,842	--	168,842
Edwin E. Smith	87,000	75,842	--	162,842
Richard S. Snell	93,000	75,842	--	168,842

(1) Mr. Barnett serves as chairman of the Governance Committee.
(2) Mr. McMahen serves as chairman of the Audit Committee.

As an honorary director, O.S. Andras receives $20,000 in cash annually for his services.

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 January 31, 2014, regarding each person known by Enterprise GP to beneficially own more than 5% of our limited partner units:

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common units	Randa Duncan Williams 1100 Louisiana Street, 10th Floor Houston, Texas 77002	340,880,379(1)	36.4%

(1) For a detailed listing of the ownership amounts that comprise Ms. Williams' 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

The following table sets forth certain information regarding the beneficial ownership of our common units as of January 31, 2014 by (i) our named executive officers; (ii) the current directors of Enterprise GP; and (iii) the current directors and executive officers (including named executive officers) of Enterprise GP as a group. All beneficial ownership information has been furnished by the respective directors and executive officers. Each person has sole voting and dispositive power over the securities shown unless indicated otherwise. The beneficial ownership amounts of certain individuals include options to acquire our common units that became exercisable in February 2014.

Ms. Williams is a DD LLC Trustee, an EPCO Trustee, an independent co-executor of the estate of Dan L. Duncan and a beneficiary of the estate. Ms. Williams is also currently Chairman and a Director of EPCO and Chairman of the Board and a Director of our general partner. Ms. Williams disclaims beneficial ownership of the limited partner units beneficially owned by the EPCO Trustees, the DD LLC Trustees and Mr. Duncan's estate except to the extent of her voting and dispositive interests in such units.

Table of Contents

Name of Beneficial Owner	Amount and Nature Of Beneficial Ownership	Percent of Class
Randa Duncan Williams:		
Units controlled by DD LLC Voting Trust		
Through DFI GP Holdings L.P.	40,844,206	4.4%
Through Dan Duncan LLC	20,881	*
Units controlled by EPCO Voting Trust:		
Through EPCO	523,306	*
Through EPCO Investments, LLC	15,241,517	1.6%
Through Duncan Family Interests, Inc.	264,179,839	28.2%
Through EPCO Holdings, Inc.	7,839,629	*
Units controlled by estate of Dan L. Duncan (1)	10,111,436	1.1%
Units controlled by Alkek and Williams, Ltd.	163,000	*
Units controlled by family trusts (2)	1,950,000	*
Units owned personally (3)	6,565	*
Total for Randa Duncan Williams	340,880,379	36.4%
Michael A. Creel (CEO) (4,5)	905,268	*
W. Randall Fowler (CFO) (4,6)	697,769	*
A. James Teague (4,7)	997,676	*
William Ordemann (4,8)	511,884	*
Stephanie C. Hildebrandt (4,9)	146,533	*
Thurmon M. Andress (10)	37,606	*
Richard H. Bachmann (11)	776,127	*
E. William Barnett	20,941	*
Larry J. Casey (12)	24,941	*
Dr. Ralph S. Cunningham (13)	587,398	*
Charles E. McMahen	41,413	*
Rex C. Ross (14)	69,852	*
Edwin E. Smith	190,330	*
Richard S. Snell	14,255	*
All current directors and executive officers of Enterprise GP, as a group (19 individuals in total) (15)	346,448,519	37.0%

* Represents a beneficial ownership of less than 1% of class

(1) The number of common units presented for the estate of Dan L. Duncan includes common units held by DD Securities LLC.

(2) The number of common units presented for Ms. Williams includes 1,512,500 common units held by family trusts for which she is the trustee but has disclaimed beneficial ownership.

(3) The number of common units presented for Ms. Williams includes 4,545 common units held by her spouse and 2,020 common units held jointly with her spouse.

(4) These individuals are the named executive officers for 2013.

(5) The number of common units presented for Mr. Creel includes 165,000 common unit options that are exercisable beginning in February 2014.

(6) The number of common units presented for Mr. Fowler includes (i) 250,000 common units held by a family limited partnership (for which he has disclaimed beneficial ownership except to the extent of his pecuniary interest) and (ii) 112,500 common unit options that are exercisable beginning in February 2014.

(7) The number of common units presented for Mr. Teague includes (i) 194,767 common units held by an immediate family member, (ii) 26,500 common units held by a family trust and (iii) 120,000 common unit options that are exercisable beginning in February 2014.

(8) The number of common units presented for Mr. Ordemann includes 105,000 common unit options that are exercisable beginning in February 2014.

(9) The number of common units presented for Ms. Hildebrandt includes 22,500 common unit options that are exercisable beginning in February 2014.

(10) The number of common units presented for Mr. Andress includes (i) 1,200 common units held by an immediate family member, (ii) 15,532 common units held by a family partnership and (iii) 712 common units held by family trusts.

(11) The number of common units presented for Mr. Bachmann includes (i) 11,438 common units held by family trusts, (ii) 4,381 common units held by an immediate family member and (iii) 120,000 common unit options that are exercisable beginning in February 2014.

(12) The number of common units presented for Mr. Casey includes 26 common units held by an immediate family member.

(13) The number of common units presented for Dr. Cunningham includes (i) 76,369 common units held by a family limited liability company, (ii) 305,506 common units held by a family limited partnership (for which he has disclaimed beneficial ownership except to the extent of his pecuniary interest), (iii) 23 common units held by the general partner of such family limited partnership and (iv) 120,000 common unit options that are exercisable beginning in February 2014.

(14) The number of common units presented for Mr. Ross includes 57,852 common units held by family trusts.

(15) Cumulatively, this group's beneficial ownership amount includes 825,000 common unit options that are exercisable beginning in February 2014.

At December 31, 2013, privately-held affiliates of EPCO (together with their respective subsidiaries) have pledged 20,000,000 of our common units that they own as security under such affiliates' credit facilities. These credit facilities include customary provisions regarding potential events of default. As a result, a change in ownership of these units could result if an event of default ultimately occurred.

Equity Ownership Guidelines

In order to further align the interests and actions of our general partner's directors and executive officers with our long-term interests and those of our general partner and other unitholders, the Board has adopted and approved certain equity ownership guidelines for our general partner's directors and executive officers. Under these 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 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.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2013 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 Part II, Item 8 of this annual report.

Plan Category	Number of Units to Be Issued Upon Exercise of Outstanding Common Unit Options	Weighted-Average Exercise Price of Outstanding Common Unit Options	Number of Units Remaining Available For Future Issuance Under Equity Compensation Plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by unitholders:			
1998 Plan (1,2)	30,000	$ 20.08	1,155,630
2008 Plan (2,3)	1,995,000	$ 26.58	4,348,820
Equity compensation plans not approved by unitholders:			
None	--	--	--
Total for equity compensation plans	2,025,000	$ 26.19	5,504,450

(1) The 30,000 unit options outstanding at December 31, 2013 are exercisable in 2014.
(2) At December 31, 2013, the maximum number of common units available for issuance under the 1998 Plan and 2008 Plan was 7,000,000 common units and 10,000,000 common units, respectively.
(3) Of the 1,995,000 unit options outstanding at December 31, 2013, 1,300,000 are exercisable in 2014 and 695,000 are exercisable in 2015.

The 1998 Plan provides for awards of our common units and other rights to our non-management 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 common units, phantom units and DERs.

The 2008 Plan provides for awards of our common units and other rights to our non-management 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 common units, phantom units, UARs, DERs, unit awards and other unit-based awards or substitute awards.

At December 31, 2013, the maximum number of common units available for issuance under the 2008 Plan was 10,000,000. This amount increased by 2,500,000 common units on January 1, 2014 and will increase by an additional 2,500,000 common units subsequently on each January 1 thereafter during the term of the 2008 Plan; provided, however, that in no event shall the maximum aggregate amount available for issuance under the 2008 Plan exceed 35,000,000 common units.

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 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report and is incorporated by reference into this Item 13.

Review and Approval of Transactions with Related Parties

We consider transactions between us and our subsidiaries and unconsolidated affiliates, on the one hand, and our executive officers and directors (or their immediate family members), our general partner or its affiliates (including other companies owned or controlled by the DD LLC Trustees or the EPCO Trustees), on the other hand, to be related party transactions. As further described below, our Partnership Agreement sets forth general procedures by which related party transactions and conflicts of interest may be approved or resolved by Enterprise GP or its Audit Committee. In addition, the Audit Committee charter, Enterprise GP's written internal review and approval policies and procedures (referred to as its "management authorization policy") and the amended and restated ASA with EPCO address specific types of related party transactions, as further described below.

At December 31, 2013, the Audit Committee was comprised of three independent directors: Charles E. McMahen, Rex C. Ross and Richard S. Snell. In accordance with its charter, the Audit Committee reviews and approves related party transactions:

§ pursuant to our Partnership Agreement or the limited liability company agreement of Enterprise GP, as such agreements may be amended from time to time;

§ in which an officer or director of Enterprise GP or any of our subsidiaries, or an immediate family member of such an officer or director, has a material financial interest or is otherwise a party;

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

§ with a value of $5 million or more (unless such transaction is equivalent to an arm's length or third party transaction); or

§ that it may otherwise deem appropriate from time to time.

The Audit Committee did not review or approve any related party transactions during the year ended December 31, 2013.

Enterprise GP's management authorization policy generally requires Board approval for asset purchase or sales transactions and capital expenditures to the extent such transactions have a value in excess of $250 million.

Any such transaction would typically also require Audit Committee review under its charter if such transaction is also a related party transaction.

The ASA governs numerous day-to-day transactions between us, Enterprise GP and EPCO and its affiliates, including the provision by EPCO of administrative and other services to us and our reimbursement to EPCO of costs, without markup or discount, for those services. The ASA was reviewed, approved and recommended to the Board by our Audit Committee, and the Board also approved it upon receiving such recommendation. For a summary of the ASA, see Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Related party transactions that are outside the scope of the ASA and that are not reviewed by the Audit Committee are subject to Enterprise GP's management authorization policy. This policy, which applies to related party transactions as well as transactions with third 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, commercial and financial transactions and legal agreements.

Partnership Agreement Standards for Audit Committee Review

Under our Partnership Agreement, whenever a potential conflict of interest exists or arises between our general partner or any of its affiliates, on the one hand, and us, any of our subsidiaries or any partner, on the other hand, any resolution or course of action by our general partner or its affiliates in respect of 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 the Audit Committee (i.e., a "Special Approval" is granted) or (ii) on terms objectively demonstrable to be no less favorable to us than those generally being provided to or available from third parties.

The Audit Committee (in connection with its Special Approval process) may consider the following when resolving conflicts of interest:

§ 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 party;

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

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

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

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

The level of review and work performed by the Audit Committee with respect to a given transaction varies depending upon the nature of the transaction and the scope of the Audit Committee's obligation. Examples of functions the Audit 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 results of operations, financial condition, cash available for distribution, properties or prospects;

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

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

§ engaging third party financial advisors to provide financial advice and assistance, including 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.

Nothing contained in our Partnership Agreement requires the Audit Committee to consider the interests of any party other than us. In the absence of the Audit Committee or our general partner acting in bad faith, the resolution, action or terms so made, taken or provided (including granting Special Approval) by the Audit Committee or our general partner with respect to such matter are deemed conclusive and binding on all persons (including all of our partners) and do not constitute a breach of Partnership Agreement, or any other agreement contemplated thereby, or a breach of any standard of care or duty imposed in our Partnership Agreement or under the Delaware Revised Uniform Limited Partnership Act or any other law, rule or regulation. Our Partnership Agreement provides that it is presumed that the resolution, action or terms made, taken or provided by the Audit 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

Each of the members of the Audit Committee, namely Messrs. McMahen, Ross and Snell, and each of the members of the Governance Committee, namely Messrs. Andress, Barnett, Casey and Smith, have been determined to be independent under the applicable NYSE listing standards and rules of the SEC. For a discussion of independence standards applicable to the Board and factors considered by the Board in making its independence determinations, please refer to "Partnership Governance" included under Part III, Item 10 of this annual report.

Item 14. *Principal Accounting 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 amounts billed to us by Deloitte & Touche for (or in) each of the years presented, as applicable (dollars in millions):

	For the Year Ended December 31, 2013	2012
Audit Fees (1)	$ 4.1	$ 3.8
Audit-Related Fees (2)	--	--
Tax Fees (3)	--	--
All Other Fees (4)	--	--

(1) Audit fees represent amounts billed for each of the years presented for (i) the audit of our annual financial statements and internal controls over financial reporting, (ii) the review of our quarterly financial statements filed on Form 10-Q and (iii) those services normally provided by Deloitte & Touche in connection with our 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 and are not reported under the section labeled "Audit Fees." No such services were rendered by Deloitte & Touche during the last two years.

(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. No such services were rendered by Deloitte & Touche during the last two years.

(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.

In order for Deloitte & Touche to maintain its independence, we are prohibited from using them to perform general bookkeeping, management or human resource functions for us, and any other service not permitted by the Public Company Accounting Oversight Board.

The Audit Committee of our general partner has approved the use of Deloitte & Touche as our independent principal accountant. In connection with its oversight responsibilities, the Audit Committee has adopted a pre-approval policy regarding any services to be performed by Deloitte & Touche. The pre-approval policy includes four primary service categories: Audit, Audit-related, Tax and Other.

When Deloitte & Touche's services are required, management and Deloitte & Touche discuss the proposed work with the Audit Committee. These discussions typically address the reasons for the project, the scope of the work to be performed and an estimate of the fee to be charged by Deloitte & Touche for such work. The Audit 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 estimate presented (the initial "pre-approved" fee amount). If at a later date, it appears that the initial pre-approved fee amount is insufficient to complete the work, management and Deloitte & Touche must present a supplemental request to the Audit Committee to increase the approved amount along with reasons for the increase. Under the pre-approval policy, management cannot act upon its own to authorize an expenditure for Deloitte & Touche services outside of the pre-approved amounts. On a quarterly basis, the Audit Committee is provided a schedule that compares the pre-approved amounts for each primary service category with the actual fees billed for each type of service. We believe the Audit Committee's pre-approval process helps to ensure the independence of our principal accountant from management.

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" beginning on page F-1 of this annual report for the financial statements included herein.

(2) Financial Statement Schedules: The separate filing of financial statement schedules has been omitted because such schedules are either not applicable or the information called for therein appears in the footnotes of our Consolidated Financial Statements.

(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).
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).
2.8	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise ETE LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2010).
2.9	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products GP, LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed September 7, 2010).
2.10	Contribution Agreement, dated as of September 30, 2010, by and between Enterprise Products

	Company and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2010).
2.11	Agreement and Plan of Merger, dated as of April 28, 2011, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPD MergerCo LLC, Duncan Energy Partners L.P. and DEP Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 29, 2011).
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	Certificate of Amendment to Certificate of Limited Partnership of Enterprise Products Partners L.P., filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.6 to Form 8-K filed November 23, 2010).
3.3	Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated November 22, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K filed November 23, 2010).
3.4	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 11, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 16, 2011).
3.5	Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC) (incorporated by reference to Exhibit 3.3 to Form S-1/A Registration Statement, Reg. No. 333-124320, filed by Enterprise GP Holdings L.P. on July 22, 2005).
3.6	Certificate of Amendment to Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC), filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.5 to Form 8-K filed November 23, 2010).
3.7	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC dated effective as of September 7, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 8, 2011).
3.8	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).
3.9	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).
3.10	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 A to Exhibit 3.1 to Form 8-K filed August 16, 2011).
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 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	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).
4.8	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).
4.9	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).
4.10	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).
4.11	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).
4.12	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).
4.13	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).
4.14	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 8-K filed September 5, 2007).
4.15	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).
4.16	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).
4.17	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).
4.18	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).
4.19	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).
4.20	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).

4.21	Nineteenth Supplemental Indenture, dated as of May 20, 2010, 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 May 20, 2010).
4.22	Twentieth Supplemental Indenture, dated as of January 13, 2011, 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 January 13, 2011).
4.23	Twenty-First Supplemental Indenture, dated as of August 24, 2011, 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 August 24, 2011).
4.24	Twenty-Second Supplemental Indenture, dated as of February 15, 2012, 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 4.25 to Form 10-Q filed May 10, 2012).
4.25	Twenty-Third Supplemental Indenture, dated as of August 13, 2012, 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 August 13, 2012).
4.26	Twenty-Fourth Supplemental Indenture, dated as of March 18, 2013, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.27	Twenty-Fifth Supplemental Indenture, dated as of February 12, 2014, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed February 12, 2014).
4.28	Form of 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 4.4 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.29	Form of 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 4.8 to Form 10-K filed March 31, 2003).
4.30	Form of 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).
4.31	Form of 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).
4.32	Form of 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).
4.33	Form of 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	Form of Global Note representing $250.0 million principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed November 4, 2005).
4.35	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.36	Form of 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).
4.37	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).
4.38	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).
4.39	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).
4.40	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).
4.41	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).
4.42	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).
4.43	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).
4.44	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).
4.45	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).
4.46	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).
4.47	Form of Global Note representing $400.0 million principal amount of 3.70% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.48	Form of Global Note representing $1.0 billion principal amount of 5.20% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.49	Form of Global Note representing $600.0 million principal amount of 6.45% Senior Notes due 2040 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.50	Form of Global Note representing $750.0 million principal amount of 3.20% Senior Notes due 2016 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).
4.51	Form of Global Note representing $750.0 million principal amount of 5.95% Senior Notes due 2041 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).
4.52	Form of Global Note representing $650.0 million principal amount of 4.05% Senior Notes due 2022 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 24, 2011).
4.53	Form of Global Note representing $600.0 million principal amount of 5.70% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 24, 2011).
4.54	Form of Global Note representing $750.0 million principal amount of 4.85% Senior Notes due 2042 with attached Guarantee (included in Exhibit 4.25 above).
4.55	Form of Global Note representing $650.0 million principal amount of 1.25% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 13, 2012).
4.56	Form of Global Note representing $1.1 billion principal amount of 4.45% Senior Notes due 2043 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed

	August 13, 2012).
4.57	Form of Global Note representing $1.25 billion principal amount of 3.35% Senior Notes due 2023 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed March 18, 2013).
4.58	Form of Global Note representing $1.0 billion principal amount of 4.85% Senior Notes due 2044 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed March 18, 2013).
4.59	Form of Global Note representing $850.0 million principal amount of 3.90% Senior Notes due 2024 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed February 12, 2014).
4.60	Form of Global Note representing $1.15 billion principal amount of 5.10% Senior Notes due 2045 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed February 12, 2014).
4.61	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 Exhibit 99.1 to Form 8-K filed May 24, 2007).
4.62	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).
4.63	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).
4.64	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).
4.65	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).
4.66	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).
4.67	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).
4.68	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).
4.69	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).
4.70	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).
4.71	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).
4.72	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).
4.73	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).
4.74	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, L.P. by U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.64 to Form 10-K filed on March 1, 2010).
4.75	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).
4.76	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).
4.77	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).
4.78	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).
4.79	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).
4.80	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 (incorporated by reference to Exhibit 4.70 to Form 10-K filed on March 1, 2010).
10.1***	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).
10.2***	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 9, 2007).
10.3***	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).
10.4***	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 10.1 to Form 10-Q filed August 9, 2010).
10.5***	Amendment to Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before August 5, 2010 (incorporated by reference to Exhibit 10.2 to Form 10-Q filed August 9, 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 10-Q filed August 9, 2010).
10.7***	Form of Employee 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).
10.8***	Amendment to Form of Employee Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before August 5, 2010 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed August 9, 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 10-Q filed August 9, 2010).
10.10***	Form of Non-Employee Director Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.6 to Form 8-K filed February 26, 2010).
10.11***	2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) (incorporated by reference to Annex A to Definitive Proxy Statement filed August 26, 2013).
10.12***	Form of Option Grant Award under the 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 (Commission File No. 333-150680) filed May 6, 2008).
10.13***	Amendment to Form of Option Grant Award under the 2008 Enterprise Products Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.9 to Form 10-Q filed August 9, 2010).
10.14***	Amendment to Form of Option Grant Award under the 2008 Enterprise Products Long-Term Incentive Plan for awards issued after February 23, 2010 and before August 5, 2010 (incorporated by reference to Exhibit 10.10 to Form 10-Q filed August 9, 2010).
10.15***	Form of Option Grant Award under the 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.11 to Form 10-Q filed August 9, 2010).
10.16***	Amendment to Form of Employee Restricted Unit Grant Award under the 2008 Enterprise Products Long-Term Incentive Plan for awards issued before August 5, 2010 (incorporated by reference to Exhibit 10.12 to Form 10-Q filed August 9, 2010).
10.17***	Form of Employee Restricted Unit Grant Award under the 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.13 to Form 10-Q filed August 9, 2010).
10.18***#	Form of Employee Phantom Unit Grant Award under the 2008 Enterprise Products Long-Term Incentive Plan.
10.19	Distribution Waiver Agreement, dated as of November 22, 2010, by and among Enterprise Products Partners L.P., EPCO Holdings, Inc. and the EPD Unitholder named therein (incorporated by reference to Exhibit 10.1 to Form 8-K filed November 23, 2010).
10.20***	Retention Agreement between Mr. William Ordemann and Enterprise Products Company dated effective October 1, 2010 (incorporated by reference to Exhibit 10.1 to Form 8-K filed October 14, 2010).
10.21***	Retention Agreement between Mr. Michael A. Creel and Enterprise Products Company dated effective December 1, 2010 (incorporated by reference to Exhibit 10.1 to Form 8-K filed December 10, 2010).
10.22***	Retention Agreement between Mr. W. Randall Fowler and Enterprise Products Company dated effective December 1, 2010 (incorporated by reference to Exhibit 10.2 to Form 8-K filed December 10, 2010).

10.23***	Retention Agreement between Mr. A. James Teague and Enterprise Products Company dated effective December 1, 2010 (incorporated by reference to Exhibit 10.3 to Form 8-K filed December 10, 2010).
10.24	Revolving Credit Agreement, dated as of September 7, 2011, among Enterprise Products Operating LLC, Canadian Enterprise Gas Products, Ltd, the Lenders party thereto, Wells Fargo Bank National Association, as Administrative Agent, The Royal Bank of Scotland PLC, Mizuho Corporate Bank, Ltd. and The Bank of Nova Scotia, as Co-syndication Agents and JPMorgan Chase Bank, N.A. and Barclays Bank PLC, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 8, 2011).
10.25	Guaranty Agreement, dated as of September 7, 2011, by and among Enterprise Products Partners L.P. and Enterprise Products Operating LLC in favor of Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed September 8, 2011).
10.26	First Amendment dated as of June 19, 2013 to Revolving Credit Agreement dated as of September 7, 2011, among Enterprise Products Operating LLC, Canadian Enterprise Gas Products, Ltd., Wells Fargo Bank, National Association, as administrative agent for each of the lenders that is a signatory or which becomes a signatory to the Credit Agreement, the Lenders party thereto, Citibank, N.A., DNB Bank ASA, New York Branch, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd. and The Royal Bank of Scotland Plc, as Co-Syndication Agents, and The Bank of Nova Scotia, SunTrust Bank, The Bank of Tokyo-Mitsubishi UFJ, Ltd., UBS Securities LLC and Royal Bank of Canada, as Co-Documentation Agents, and Wells Fargo Securities, LLC, Citigroup Global Markets Inc., DNB Markets, Inc., J.P. Morgan Securities LLC, Mizuho Corporate Bank, Ltd., RBS Securities Inc., Scotia Capital, SunTrust Robinson Humphrey, Inc., and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.3 to Form 8-K filed on June 20, 2013).
10.27	Sixth Amended and Restated Administrative Services Agreement, dated as of September 7, 2011, by and among Enterprise Products Company, EPCO Holdings, Inc., Enterprise Products Holdings LLC, Enterprise Products Partners L.P., Enterprise Products OLPGP, Inc., Enterprise Products Operating LLC, the TEPPCO Parties named therein, Enterprise ETE LLC and the DEP Parties named therein (incorporated by reference to Exhibit 10.3 to Form 8-K filed September 8, 2011).
10.28	Equity Distribution Agreement, dated November 12, 2013, by and among Enterprise Products Partners L.P., Enterprise Products OLPGP, Inc., Enterprise Products Operating LLC and Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., J.P Morgan Securities LLC, Mitsubishi UFJ Securities (USA), Inc., Mizuho Securities USA Inc., Morgan Stanley & Co. LLC, Raymond James & Associates, Inc., RBC Capital Markets, LLC, Scotia Capital (USA) Inc., SunTrust Robinson Humphrey, Inc., UBS Securities LLC and Wells Fargo Securities, LLC (incorporated by reference to Exhibit 1.1 to Form 8-K filed November 12, 2013).
10.29	364-Day Revolving Credit Agreement dated as of June 19, 2013, among Enterprise Products Operating LLC, the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent and Swingline Lender, Citibank, N.A., DNB Bank ASA, New York Branch, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., and The Royal Bank of Scotland Plc, as Co-Syndication Agents, and The Bank of Nova Scotia, SunTrust Bank, The Bank of Tokyo-Mitsubishi UFJ, Ltd., UBS Securities LLC and Royal Bank of Canada, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Form 8-K filed on June 20, 2013).
10.30	Guaranty Agreement, dated as of June 19, 2013, by Enterprise Products Partners L.P. in favor of Wells Fargo Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed on June 20, 2013).
12.1#	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2013, 2012, 2011, 2010 and 2009.
21.1#	List of consolidated subsidiaries as of February 1, 2014.
23.1#	Consent of Deloitte & Touche LLP.

31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2013.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2013.
32.1#	Sarbanes-Oxley Section 906 certification of Michael A. Creel for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2013.
32.2#	Sarbanes-Oxley Section 906 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2013.
101.CAL#	XBRL Calculation Linkbase Document
101.DEF#	XBRL Definition Linkbase Document
101.INS#	XBRL Instance Document
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 Products Partners L.P., Enterprise GP Holdings L.P, TEPPCO Partners, L.P. and TE Products Pipeline Company, LLC are 1-14323, 1-32610, 1-10403 and 1-13603, respectively.
***	Identifies management contract and compensatory plan arrangements.
#	Filed with this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on March 3, 2014.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)

By: Enterprise Products Holdings LLC, as General Partner

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 Exchange 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 3, 2014.

Signature	Title (Position with Enterprise Products Holdings LLC)
/s/ Randa Duncan Williams Randa Duncan Williams	Director and Chairman of the Board
/s/ Thurmon M. Andress Thurmon M. Andress	Director
/s/ Richard H. Bachmann Richard H. Bachmann	Director
/s/ E. William Barnett E. William Barnett	Director
/s/ Larry J. Casey Larry J. Casey	Director
/s/ Michael A. Creel Michael A. Creel	Director and Chief Executive Officer
/s/ Dr. Ralph S. Cunningham Dr. Ralph S. Cunningham	Director
/s/ W. Randall Fowler W. Randall Fowler	Director, Executive Vice President and Chief Financial Officer
/s/ Charles E. McMahen Charles E. McMahen	Director
/s/ Rex C. Ross Rex C. Ross	Director
/s/ Edwin E. Smith Edwin E. Smith	Director
/s/ Richard S. Snell Richard S. Snell	Director
/s/ A. James Teague A. James Teague	Director and Chief Operating Officer
/s/ Michael J. Knesek Michael J. Knesek	Senior Vice President, Controller and Principal Accounting Officer

Item 8. Financial Statements and Supplementary Data.

ENTERPRISE PRODUCTS PARTNERS L.P.
INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products Holdings LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Enterprise Products Partners L.P. and subsidiaries (the “Company”) as of December 31, 2013 and 2012, and the related statements of consolidated operations, comprehensive income, cash flows, and equity for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits 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 the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Enterprise Products Partners L.P. and subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 3, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 3, 2014

ENTERPRISE PRODUCTS PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

ASSETS	December 31, 2013	December 31, 2012
Current assets:		
Cash and cash equivalents	$ 56.9	$ 16.1
Restricted cash	65.6	4.3
Accounts receivable – trade, net of allowance for doubtful accounts of $7.5 at December 31, 2013 and $13.2 at December 31, 2012	5,475.5	4,350.9
Accounts receivable – related parties	6.8	2.5
Inventories	1,093.1	1,088.4
Prepaid and other current assets	325.5	380.9
Total current assets	7,023.4	5,843.1
Property, plant and equipment, net	26,946.6	24,846.4
Investments in unconsolidated affiliates	2,437.1	1,394.6
Intangible assets, net of accumulated amortization of $1,150.0 at December 31, 2013 and $1,050.0 at December 31, 2012	1,462.2	1,566.8
Goodwill	2,080.0	2,086.8
Other assets	189.4	196.7
Total assets	$ 40,138.7	$ 35,934.4
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 11)	$ 1,125.0	$ 1,546.6
Accounts payable – trade	723.7	764.5
Accounts payable – related parties	150.5	127.1
Accrued product payables	5,608.7	4,476.2
Accrued interest	304.3	300.8
Other current liabilities	326.5	540.5
Total current liabilities	8,238.7	7,755.7
Long-term debt (see Note 11)	16,226.5	14,655.2
Deferred tax liabilities	60.8	22.5
Other long-term liabilities	172.3	205.0
Commitments and contingencies (see Note 17)		
Equity: (see Note 12)		
Partners' equity:		
Limited partners:		
Common units (935,685,008 units outstanding at December 31, 2013 and 898,813,337 units outstanding at December 31, 2012)	15,573.8	13,439.6
Class B units (4,520,431 units outstanding at December 31, 2012)	--	118.5
Total limited partners' equity	15,573.8	13,558.1
Accumulated other comprehensive loss	(359.0)	(370.4)
Total partners' equity	15,214.8	13,187.7
Noncontrolling interests	225.6	108.3
Total equity	15,440.4	13,296.0
Total liabilities and equity	$ 40,138.7	$ 35,934.4

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in millions, except per unit amounts)

	For the Year Ended December 31,		
	2013	**2012**	**2011**
Revenues:			
Third parties	$ 47,661.1	$ 42,509.8	$ 43,537.9
Related parties	65.9	73.3	775.1
Total revenues (see Note 13)	47,727.0	42,583.1	44,313.0
Costs and expenses:			
Operating costs and expenses:			
Third parties	43,300.8	38,602.2	39,553.5
Related parties	937.9	765.7	1,765.0
Total operating costs and expenses	44,238.7	39,367.9	41,318.5
General and administrative costs:			
Third parties	74.0	78.9	72.8
Related parties	114.3	91.4	109.0
Total general and administrative costs	188.3	170.3	181.8
Total costs and expenses (see Note 13)	44,427.0	39,538.2	41,500.3
Equity in income of unconsolidated affiliates	167.3	64.3	46.4
Operating income	3,467.3	3,109.2	2,859.1
Other income (expense):			
Interest expense	(802.5)	(771.8)	(744.1)
Interest income	0.9	0.8	1.1
Other, net	(1.1)	72.6	(0.6)
Total other expense, net	(802.7)	(698.4)	(743.6)
Income before income taxes	2,664.6	2,410.8	2,115.5
Benefit from (provision for) income taxes (see Note 15)	(57.5)	17.2	(27.2)
Net income	2,607.1	2,428.0	2,088.3
Net income attributable to noncontrolling interests (see Note 12)	(10.2)	(8.1)	(41.4)
Net income attributable to limited partners	$ 2,596.9	$ 2,419.9	$ 2,046.9
Earnings per unit: (see Note 16)			
Basic earnings per unit	$ 2.90	$ 2.81	$ 2.48
Diluted earnings per unit	$ 2.82	$ 2.71	$ 2.38

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
(Dollars in millions)

	For the Year Ended December 31,		
	2013	**2012**	**2011**
Net income	$ 2,607.1	$ 2,428.0	$ 2,088.3
Other comprehensive income (loss):			
Cash flow hedges:			
Commodity derivative instruments:			
Changes in fair value of cash flow hedges	(46.9)	17.3	(221.9)
Reclassification of losses to net income	22.1	14.2	232.3
Interest rate derivative instruments:			
Changes in fair value of cash flow hedges	6.6	(70.2)	(333.2)
Reclassification of losses to net income	29.2	16.2	6.3
Total cash flow hedges	11.0	(22.5)	(316.5)
Other	0.4	3.5	(1.3)
Total other comprehensive income (loss)	11.4	(19.0)	(317.8)
Comprehensive income	2,618.5	2,409.0	1,770.5
Comprehensive income attributable to noncontrolling interests	(10.2)	(8.1)	(41.4)
Comprehensive income attributable to limited partners	$ 2,608.3	$ 2,400.9	$ 1,729.1

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in millions)

	For the Year Ended December 31,		
	2013	**2012**	**2011**
Operating activities:			
Net income	$ 2,607.1	$ 2,428.0	$ 2,088.3
Reconciliation of net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	1,217.6	1,104.9	1,007.0
Non-cash asset impairment charges (see Note 6)	92.6	63.4	27.8
Equity in income of unconsolidated affiliates	(167.3)	(64.3)	(46.4)
Distributions received from unconsolidated affiliates	251.6	116.7	156.4
Gains attributable to asset sales and insurance recoveries (see Note 19)	(83.3)	(86.4)	(155.7)
Deferred income tax expense (benefit)	37.9	(66.2)	12.1
Changes in fair market value of derivative instruments	1.4	(29.5)	(25.7)
Net effect of changes in operating accounts (see Note 19)	(97.6)	(582.5)	266.9
Other operating activities	5.5	6.8	(0.2)
Net cash flows provided by operating activities	3,865.5	2,890.9	3,330.5
Investing activities:			
Capital expenditures	(3,408.2)	(3,621.9)	(3,867.5)
Contributions in aid of construction costs	26.0	23.4	24.9
Decrease (increase) in restricted cash	(61.3)	34.2	60.2
Investments in unconsolidated affiliates	(1,094.1)	(609.5)	(30.0)
Proceeds from asset sales and insurance recoveries (see Note 19)	280.6	1,198.8	1,053.8
Other investing activities	(0.5)	(43.8)	(19.0)
Cash used in investing activities	(4,257.5)	(3,018.8)	(2,777.6)
Financing activities:			
Borrowings under debt agreements	13,852.8	8,363.1	8,324.1
Repayments of debt	(12,680.6)	(6,676.4)	(7,375.8)
Debt issuance costs	(23.7)	(21.5)	(34.7)
Monetization of interest rate derivative instruments (see Note 6)	(168.8)	(147.8)	(23.2)
Cash distributions paid to limited partners (see Note 12)	(2,400.3)	(2,178.6)	(1,974.3)
Cash distributions paid to noncontrolling interests (see Note 12)	(8.9)	(13.3)	(60.7)
Cash contributions from noncontrolling interests (see Note 12)	115.4	6.6	8.5
Net cash proceeds from the issuance of common units	1,792.0	816.8	542.9
Other financing activities	(45.1)	(24.7)	(5.4)
Cash provided by (used in) financing activities	432.8	124.2	(598.6)
Net change in cash and cash equivalents	40.8	(3.7)	(45.7)
Cash and cash equivalents, January 1	16.1	19.8	65.5
Cash and cash equivalents, December 31	$ 56.9	$ 16.1	$ 19.8

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED EQUITY
(See Note 12 for Unit History, Accumulated Other Comprehensive Income (Loss) and Noncontrolling Interests)
(Dollars in millions)

	Partners' Equity			
	Limited Partners	**Accumulated Other Comprehensive Income (Loss)**	**Noncontrolling Interests**	**Total**
Balance, December 31, 2010	$ 11,406.7	$ (32.5)	$ 526.6	$ 11,900.8
Net income	2,046.9	--	41.4	2,088.3
Cash distributions paid to limited partners	(1,974.3)	--	--	(1,974.3)
Cash distributions paid to noncontrolling interests	--	--	(60.7)	(60.7)
Cash contributions from noncontrolling interests	--	--	8.5	8.5
Net cash proceeds from the issuance of common units	542.9	--	--	542.9
Acquisition of noncontrolling interest in subsidiary	(5.4)	--	(9.6)	(15.0)
Amortization of fair value of equity-based awards	50.9	--	0.1	51.0
Issuance of common units pursuant to Duncan Merger (see Note 12)	402.8	(1.1)	(401.7)	--
Cash flow hedges	--	(316.5)	--	(316.5)
Other	(5.7)	(1.3)	1.3	(5.7)
Balance, December 31, 2011	12,464.8	(351.4)	105.9	12,219.3
Net income	2,419.9	--	8.1	2,428.0
Cash distributions paid to limited partners	(2,178.6)	--	--	(2,178.6)
Cash distributions paid to noncontrolling interests	--	--	(13.3)	(13.3)
Cash contributions from noncontrolling interests	--	--	6.6	6.6
Net cash proceeds from the issuance of common units	816.8	--	--	816.8
Amortization of fair value of equity-based awards	58.9	--	--	58.9
Cash flow hedges	--	(22.5)	--	(22.5)
Other	(23.7)	3.5	1.0	(19.2)
Balance, December 31, 2012	13,558.1	(370.4)	108.3	13,296.0
Net income	2,596.9	--	10.2	2,607.1
Cash distributions paid to limited partners	(2,400.3)	--	--	(2,400.3)
Cash distributions paid to noncontrolling interests	--	--	(8.9)	(8.9)
Cash contributions from noncontrolling interests	--	--	115.4	115.4
Net cash proceeds from the issuance of common units	1,792.0	--	--	1,792.0
Amortization of fair value of equity-based awards	72.4	--	--	72.4
Cash flow hedges	--	11.0	--	11.0
Other	(45.3)	0.4	0.6	(44.3)
Balance, December 31, 2013	$ 15,573.8	$ (359.0)	$ 225.6	$ 15,440.4

See Notes to Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

With the exception of per unit amounts, or as noted within the context of each disclosure, the dollar amounts presented in the tabular data within these disclosures are stated in millions of dollars.

KEY REFERENCES USED IN THESE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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

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

In addition to owning our general partner, affiliates of privately held EPCO owned approximately 36.4% of our limited partner interests at December 31, 2013.

References to "TEPPCO" mean TEPPCO Partners, L.P. prior to its merger with one of our wholly owned subsidiaries in October 2009 (the "TEPPCO Merger").

Note 1. Partnership Operations, Organization and Basis of Presentation

General

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO and are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, petrochemicals and refined products.

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States ("U.S."), Canada and Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals (including liquefied petroleum gas or "LPG"); crude oil gathering, transportation, storage and terminals; offshore production platforms; petrochemical and refined products transportation and services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. Our assets include approximately 51,000 miles of onshore and offshore pipelines; 200 million barrels ("MMBbls") of storage capacity for NGLs, petrochemicals, refined products and crude oil; and 14 billion cubic feet ("Bcf") of natural gas storage capacity. In addition, our asset portfolio includes 24 natural gas processing plants, 22 NGL and propylene fractionators, six offshore hub platforms located in the Gulf of Mexico, a butane isomerization complex, NGL import and LPG export terminals, and octane enhancement and high-purity isobutylene production facilities.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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. All activities included in our former sixth reportable business segment, Other Investments, ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our previously held investment in Energy Transfer Equity L.P. (together with its subsidiaries, "Energy Transfer Equity") (see "Liquidation of Investment in Energy Transfer Equity" under Note 9).

We are 100% owned by our limited partners from an economic perspective. We are managed and controlled by Enterprise GP, which has a non-economic general partner interest in us. We, Enterprise GP, EPCO and Dan Duncan LLC are affiliates under the collective common control of the DD LLC Trustees and the EPCO Trustees. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers. See Note 14 for information regarding the ASA and other related party matters.

Completion of Duncan Merger in September 2011

Duncan Energy Partners L.P. ("Duncan Energy Partners") was formed by Enterprise Products Partners in September 2006 and completed its initial public offering in February 2007 (NYSE: DEP). Duncan Energy Partners was under common control with Enterprise by affiliates of EPCO and its business purpose was to acquire, own and operate midstream energy assets.

In April 2011, we, our general partner, EPD MergerCo LLC ("Duncan MergerCo," our wholly owned subsidiary), Duncan Energy Partners and DEP Holdings, LLC ("DEP GP," the general partner of Duncan Energy Partners) entered into a merger agreement (the "Duncan Merger Agreement"). In September 2011, the Duncan Merger Agreement was approved by the unitholders of Duncan Energy Partners and the merger of Duncan MergerCo with and into Duncan Energy Partners and related transactions were completed, with Duncan Energy Partners surviving such merger as our wholly owned subsidiary (collectively, we refer to these transactions as the "Duncan Merger").

Each issued and outstanding common unit of Duncan Energy Partners was cancelled and converted into the right to receive our limited partner common units based on an exchange ratio of 1.01 Enterprise common units for each Duncan Energy Partners common unit. We issued 24,277,310 of our common units (net of fractional common units cashed out) to the former public unitholders of Duncan Energy Partners as consideration in the Duncan Merger. We did not issue any common units as merger consideration to our subsidiaries that owned limited partner interests in Duncan Energy Partners.

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

Note 2. Summary of Significant Accounting Policies

Allowance for Doubtful Accounts

Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts, including those related to natural gas imbalances. Our procedure for estimating the allowance for doubtful accounts is based on: (i) historical experience with customers, (ii) the perceived financial stability of customers based on our research and (iii) the levels of credit we grant to customers. In addition, we may increase the allowance for doubtful accounts in response to the specific identification of customers involved in bankruptcy proceedings and similar financial difficulties. On a routine basis, we review estimates associated with the allowance for doubtful accounts to ensure that we have recorded sufficient reserves to cover potential losses.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents our allowance for doubtful accounts activity for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
Balance at beginning of period	$ 13.2	$ 13.4	$ 18.4
Charged to costs and expenses	2.1	0.3	0.8
Deductions (1)	(7.8)	(0.5)	(5.8)
Balance at end of period	$ 7.5	$ 13.2	$ 13.4

(1) The 2013 deduction is primarily due to the write-off of certain amounts attributable to companies in bankruptcy and amounts we believe are no longer collectible. The 2011 deduction amount is primarily due to our reassessment of the allowance for doubtful accounts as a result of improved credit ratings of a customer, which reduced our exposure to potential uncollectibility.

See "Credit Risk Due to Industry Concentrations" in Note 18 for additional information.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and highly liquid investments with original maturities of less than three months from the date of purchase.

Consolidation Policy

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of all intercompany accounts and transactions. We also consolidate other entities and ventures in which we possess a controlling financial interest as well as partnership interests where we are the sole general partner of the partnership. We evaluate our financial interests in business enterprises to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own. Third party or affiliate ownership interests in our controlled subsidiaries are presented as noncontrolling interests. See Note 12 for information regarding noncontrolling interests.

If the entity is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3% and 50%, unless our interest is so minor that we have virtually no influence over the investee's operating and financial policies. For all other types of investments, we apply the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the investee's operating and financial policies. In consolidation, we eliminate our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates to the extent such amounts remain on our Consolidated Balance Sheets (or those of our equity method investments) in inventory or similar accounts.

We account for investments using the cost method when our ownership interest in an entity does not provide us with significant influence or when we have virtually no influence over the investee's operating and financial policies. At December 31, 2013, we did not have any significant investments accounted for using the cost method.

Contingencies

Certain conditions may exist as of the date our consolidated financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the need for accounting recognition or disclosure of these contingencies, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in such proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

We accrue an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when it is believed to be only reasonably possible or remote.

For contingencies where an unfavorable outcome is reasonably possible and the impact would be material, we disclose the nature of the contingency and, if feasible, an estimate of the possible loss or range of loss.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed. See Note 17 for additional information regarding our contingencies.

Current Assets and Current Liabilities

We present, as individual captions in our Consolidated Balance Sheets, all components of current assets and current liabilities that exceed 5% of total current assets and liabilities, respectively.

Deferred Revenues

Amounts billed in advance of the period in which the service is rendered or product delivered are recorded as deferred revenue. At December 31, 2013 and 2012, deferred revenues totaled $108.7 million and $82.1 million, respectively, and were recorded as a component of other current and long-term liabilities, as appropriate, on our Consolidated Balance Sheets. See Note 4 for information regarding our revenue recognition policies.

Derivative Instruments

We use derivative instruments such as futures, swaps, options, forward contracts and other arrangements to manage price risks associated with inventories, firm commitments, interest rates, foreign currencies and certain anticipated future commodity transactions. To qualify for hedge accounting, the hedged item must expose us to risk and the related derivative instrument must reduce the exposure to that risk and meet specific hedge documentation requirements related to designation dates, expectations for hedge effectiveness and the probability that hedged future transactions will occur as forecasted. We formally designate derivative instruments as hedges and document and assess their effectiveness at inception of the hedge and on a monthly basis thereafter. Forecasted transactions are evaluated for the probability of occurrence and are periodically back-tested once the forecasted period has passed to determine whether similarly forecasted transactions are probable of occurring in the future.

For certain physical forward commodity derivative contracts, we apply the normal purchase/normal sale exception, whereby changes in the mark-to-market values of such contracts are not recognized in income. As a result, the revenues and expenses associated with such physical transactions are recognized during the period when volumes are physically delivered or received. Physical forward commodity contracts subject to this exception are evaluated for the probability of future delivery and are periodically back-tested once the forecasted period has passed to determine whether similar forward contracts are probable of physical delivery in the future. See Note 6 for additional information regarding our derivative instruments.

Earnings Per Unit

Earnings per unit is based on the amount of net income attributable to limited partners and the weighted-average number of limited partner units outstanding during a period. See Note 16 for additional information regarding our earnings per unit amounts.

Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management’s best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. 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, 2013, 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.

The following table presents the activity of our environmental reserves for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
Balance at beginning of period	$ 13.7	$ 12.3	$ 12.4
Charged to costs and expenses	3.9	13.9	9.3
Acquisition-related additions and other	0.7	5.2	1.0
Deductions	(8.4)	(17.7)	(10.4)
Balance at end of period	$ 9.9	$ 13.7	$ 12.3

At December 31, 2013 and 2012, $6.0 million and $6.5 million, respectively, of our environmental reserves were classified as current liabilities.

Equity-based Awards

See Note 5 for information regarding our accounting for equity-based awards.

Estimates

Preparing our consolidated financial statements in conformity with U.S. generally accepted accounting principles ("GAAP") requires us to make estimates that affect amounts presented in the financial statements. Our most significant estimates relate to (i) the useful lives and depreciation/amortization methods used for fixed and identifiable intangible assets; (ii) measurement of fair value and projections used in impairment testing of fixed and intangible assets (including goodwill); (iii) contingencies; and (iv) revenue and expense accruals.

Actual results could differ materially from our estimates. On an ongoing basis, we review our estimates based on currently available information. Any changes in the facts and circumstances underlying our estimates may require us to update such estimates, which could have a material impact on our consolidated financial statements.

Impairment Testing for Goodwill

Our goodwill amounts are assessed for impairment on a routine annual basis or when impairment indicators are present. If such indicators occur (e.g., the loss of a significant customer or technological obsolescence of assets), the estimated fair value of the reporting unit to which the goodwill is assigned is determined and compared to its carrying value. If the fair value of the reporting unit is less than its carrying value including associated goodwill amounts, a charge to earnings is recorded to reduce the carrying value of the goodwill to its implied fair value.

Impairment Testing for Long-Lived Assets

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset's carrying value exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge equal to the excess of the asset's carrying value over its estimated fair value is recorded. Fair value is defined as the price that would be received to sell an asset or be paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. We measure fair value using market price indicators or, in the absence of such data, appropriate valuation techniques. See Note 6 for information regarding impairment charges related to long-lived assets during 2013, 2012 and 2011.

Impairment Testing for Unconsolidated Affiliates

We evaluate our equity method investments for impairment when events or changes in circumstances indicate that there is a loss in value of the investment attributable to an other than temporary decline. Examples of such events or changes in circumstances include continuing operating losses of the entity and/or long-term negative changes in the entity's industry. In the event we determine that the loss in value of an investment is an other than temporary decline, we record a charge to equity earnings to adjust the carrying value of the investment to its estimated fair value. During 2013, we evaluated our equity method investment in Neptune for impairment. As a result of this evaluation, we recorded a $4.8 million non-cash impairment charge that is a component of equity in earnings from unconsolidated affiliates for the year ended December 31, 2013. There were no impairment charges in 2012 and 2011 related to our equity method investments. See Note 9 for additional information regarding our equity method investments.

Income Taxes

Publicly traded partnerships like ours are treated as corporations unless they have 90% or more in qualifying income (as that term is defined in the IRS Internal Revenue Code). We satisfied this requirement in each of the years ended December 31, 2013, 2012 and 2011 and, as a result, are not subject to federal income tax. However, our partners are individually responsible for paying federal income taxes on their share of our taxable income. Net earnings for financial statement purposes may differ significantly from taxable income reportable to our unitholders as a result of differences between the tax basis and financial reporting basis of certain assets and liabilities and other factors. We do not have access to information regarding each partner's individual tax basis in our limited partner interests. See Note 15 for additional information regarding our income taxes.

Inventories

Inventories primarily consist of NGLs, petrochemicals, refined products, crude oil and natural gas volumes that are valued at the lower of average cost or market. We capitalize, as a cost of inventory, shipping and handling charges (e.g., pipeline transportation and storage fees) and other related costs associated with purchased volumes. As volumes are sold and delivered out of inventory, the cost of these volumes (including freight-in charges that have been capitalized as part of inventory cost) are charged to operating costs and expenses. Shipping and handling fees associated with products we sell and deliver to customers are charged to operating costs and expenses as incurred. See Note 7 for additional information regarding our inventories.

Other Non-Operating Income

The following table presents the components of "Other, net" as presented on our Statements of Consolidated Operations for the periods indicated:

	For the Year Ended December 31,		
	2013	**2012**	**2011**
Gain on sales of available-for-sale securities of Energy Transfer Equity (1)	$ --	$ 68.8	$ --
Distribution income from Energy Transfer Equity	--	4.1	--
Other	(1.1)	(0.3)	(0.6)
Total	$ (1.1)	$ 72.6	$ (0.6)

(1) See Note 9 for information regarding the liquidation of our investment in limited partnership units of Energy Transfer Equity.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Expenditures for additions, improvements and other enhancements to property, plant and equipment are capitalized, and minor replacements, maintenance, and repairs that do not extend asset life or add value are charged to expense as incurred. When property, plant and equipment assets are retired or otherwise disposed of, the related cost and accumulated depreciation is removed from the accounts and any resulting gain or loss is included in results of operations for the respective period.

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of an asset. Our estimate of depreciation expense incorporates management assumptions regarding the useful economic lives and residual values of our assets. With respect to midstream energy assets such as natural gas gathering systems that are reliant upon a specific natural resource basin for throughput volumes, the anticipated useful economic life of such assets may be limited by the estimated life of the associated natural resource basin from which the assets derive benefit. Our forecast of the remaining life for the applicable resource basins is based on several factors, including information published by the U.S. Energy Information Administration. Where appropriate, we use other depreciation methods (generally accelerated) for tax purposes.

Leasehold improvements are recorded as a component of property, plant and equipment. The cost of leasehold improvements is charged to earnings using the straight-line method over the shorter of (i) the remaining lease term or (ii) the estimated useful lives of the improvements. We consider renewal terms that are deemed reasonably assured when estimating remaining lease terms.

Our assumptions regarding the useful economic lives and residual values of our assets may change in response to new facts and circumstances, which would prospectively impact our depreciation expense amounts. Examples of such circumstances include, but are not limited to: (i) changes in laws and regulations that limit the estimated economic life of an asset; (ii) changes in technology that render an asset obsolete; (iii) changes in expected salvage values or (iv) significant changes in the forecast life of the applicable resource basins, if any. See Note 8 for additional information regarding our property, plant and equipment.

Certain of our plant operations entail periodic planned outages for major maintenance activities. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services and related items. We use the expense-as-incurred method for our planned major maintenance activities for plant operations; however, the cost of annual planned major maintenance projects for such plants are deferred and recognized ratably until the next planned annual outage. With regard to the planned major maintenance activities on our marine transportation assets and underground storage caverns, we use the deferral method to account for such costs. Under this method, major maintenance costs are capitalized and amortized over the period until the next major overhaul or cavern integrity project.

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. ARO amounts are measured at their estimated fair value using expected present value techniques. Over time, the ARO liability is accreted to its present value (through accretion expense) and the capitalized amount is depreciated over the remaining useful life of the related long-lived asset. We will incur a gain or loss to the extent that our ARO liabilities are not settled at their recorded amounts.

Restricted Cash

Restricted cash represents amounts held in segregated bank accounts by our clearing brokers as margin in support of our commodity derivative instruments portfolio and related physical purchases and sales of natural gas, crude oil, refined products and NGLs. Additional cash may be restricted to maintain our commodity derivative instruments portfolio as prices fluctuate or deposit requirements change. At December 31, 2013 and 2012, our restricted cash amounts were $65.6 million and $4.3 million, respectively. See Note 6 for information regarding our derivative instruments and hedging activities.

Revenue Recognition

In general, we recognize revenue from our customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered,

(iii) the buyer's price is fixed or determinable and (iv) collectibility is reasonably assured. See Note 4 for additional information regarding our revenue recognition policies.

Note 3. Recent Accounting Developments

The Financial Accounting Standards Board ("FASB") and the International Accounting Standards Board ("IASB") continue their joint project to converge U.S. GAAP and International Financial Reporting Standards in the area of revenue recognition. As currently drafted, the converged standard eliminates the transaction- and industry-specific revenue recognition guidance under current U.S. GAAP and replaces it with a principles based approach for determining revenue recognition. It is expected that the new standard will be issued during the first quarter of 2014. Although the FASB and IASB continue their deliberations on certain revenue recognition topics, we continue to monitor developments in connection with the proposed new accounting guidance. Based on information currently available, the effective date of the new standard would be January 1, 2017.

Note 4. Revenue Recognition

The following information summarizes our revenue recognition policies by business segment. See Note 13 for general information regarding our business segments.

NGL Pipelines & Services

In our natural gas processing business, we utilize contracts that are either fee-based, commodity-based or a combination of the two. When a cash fee for natural gas processing services is stipulated by a contract, we record revenue when a producer's natural gas has been processed and redelivered. Our commodity-based contracts include keepwhole and margin-band contracts, percent-of-liquids contracts, percent-of-proceeds contracts and contracts featuring a combination of commodity and fee-based terms. Under keepwhole and margin-band contracts, we take ownership of mixed NGLs extracted from the producer's natural gas stream while replacing the equivalent quantity of energy on a natural gas basis to producers. We recognize revenue when the extracted NGLs are delivered and sold to customers under NGL marketing sales contracts. Under percent-of-liquids contracts, we take ownership of a portion of the mixed NGLs extracted from the producer's natural gas stream (in lieu of a cash processing fee) and recognize revenue when the extracted NGLs are delivered and sold to customers under NGL marketing sales contracts. Under percent-of-proceeds contracts, we share in the proceeds generated from the sale of mixed NGLs we extract on the producer's behalf (in lieu of a cash processing fee). In certain cases, we also utilize contracts that include a combination of commodity-based terms (such as those described above) and fee-based terms.

Our NGL marketing activities generate revenues from the sale and delivery of NGLs we take title to through our natural gas processing activities (i.e., our equity NGL production) and open market and contract purchases. Revenue from these sales contracts is recognized when the NGLs are delivered to customers. In general, sales prices referenced in these contracts are market-based and may include pricing differentials for factors such as delivery location or NGL product quality.

Revenues from NGL pipeline transportation contracts and tariffs are generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies, including the Federal Energy Regulatory Commission ("FERC"), or contractual arrangements. Typically, pipeline transportation revenue is recognized when volumes are delivered to customers. However, under certain NGL pipeline transportation agreements (e.g., those associated with committed shippers on our Texas Express Pipeline, Front Range Pipeline and ATEX Express pipeline), customers are required to ship a minimum volume over an agreed-upon period. These arrangements typically entail the shipper paying a transportation fee based on a minimum volume commitment, with a provision that allows the shipper to make up any volume shortfalls over the agreed-upon period (referred to as shipper "make-up rights"). Revenue pursuant to such agreements, including that associated with make-up rights, is recognized at the earlier of when the volume is shipped, when the shipper's ability to meet the minimum volume commitment has expired, or when the pipeline is otherwise released from its performance obligation.

We collect storage revenue under our NGL and related product storage contracts based on the number of days a customer has volumes in storage multiplied by a storage fee (as defined in each contract). Under these contracts, revenue is recognized ratably over the length of the storage period. With respect to capacity reservation agreements, we collect a fee for reserving storage capacity for certain customers in our underground storage wells. Customers pay reservation fees based on the level of storage capacity reserved rather than the actual volumes stored. Under these agreements, revenue is recognized ratably over the specified reservation period. When a customer exceeds its reserved capacity, we charge that customer excess storage fees, which are recognized in the period of occurrence. In addition, we generally charge customers throughput fees based on volumes delivered into and subsequently withdrawn from storage, which are recognized as the service is provided.

We typically earn revenues from NGL fractionation under fee-based arrangements. These fees are contractually subject to adjustment for changes in certain fractionation expenses (e.g., natural gas fuel costs). Under fee-based arrangements, revenue is recognized in the period services are provided. At our Norco facility in Louisiana, we perform fractionation services for certain customers under percent-of-liquids contracts. Such contracts allow us to retain a contractually determined percentage of the customer's fractionated NGLs as payment for services rendered. Revenue is recognized from such arrangements when we sell and deliver the retained NGLs to customers.

Revenue from NGL import and LPG export terminaling activities is recorded in the period services are provided. Customers are typically billed a fee per unit of volume loaded or unloaded. With respect to our export terminal operations, revenue may also include deficiency fees charged to customers who reserve capacity at our export facilities and later fail to use such capacity. Deficiency fee revenue is recognized when the customer fails to utilize the specified export capacity as required by contract.

Onshore Natural Gas Pipelines & Services

Our onshore natural gas pipelines typically generate revenues from transportation agreements under which shippers are billed a fee per unit of volume transported multiplied by the volume gathered or delivered. Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies, including the FERC, or contractual arrangements. Certain of our onshore natural gas pipelines offer firm capacity reservation services whereby the shipper pays a contractual fee based on the level of throughput capacity reserved (whether or not the shipper actually utilizes such capacity). Revenues are recognized when volumes have been delivered to customers or in the period we provide firm capacity reservation services.

Under our natural gas storage revenue contracts, there are typically two components: (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. Revenue from demand payments is recognized during the period the customer reserves capacity. Revenue from storage fees is recognized in the period the services are provided.

Our natural gas marketing activities generate revenue from the sale and delivery to local gas distribution companies and other customers of natural gas purchased from producers, regional natural gas processing plants and the open market. Revenue from these sales contracts is recognized when the natural gas is delivered to customers. In general, sales prices referenced in the underlying contracts are market-based and may include pricing differentials for factors such as delivery location.

Onshore Crude Oil Pipelines & Services

Revenue from crude oil transportation is generally based upon a fixed fee per barrel transported multiplied by the volume delivered. Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies, including the FERC, or contractual arrangements. Typically, revenue associated with these arrangements is recognized when volumes have been delivered; however, under certain of our crude oil pipeline transportation agreements, customers are required to ship a minimum volume over an agreed-upon period, with make-up rights. Revenue pursuant to such agreements, including that associated with make-up rights, is recognized at the earlier of when the volume is shipped, when the shipper's ability to meet the minimum volume commitment has expired, or when the pipeline is otherwise released from its performance obligation.

Under our crude oil terminaling agreements, we charge customers for crude oil storage based on the number of days a customer has volumes in storage multiplied by a contractual storage fee. Under these contracts, revenue is recognized ratably over the length of the storage period. With respect to storage capacity reservation agreements, we collect a fee for reserving storage capacity for customers at our terminals. Under these agreements, revenue is recognized ratably over the specified reservation period. In addition, we charge our customers throughput (or "pumpover") fees based on volumes withdrawn from our terminals. Revenue is also generated from fee-based trade documentation services and is recognized as services are completed.

Our crude oil marketing activities generate revenues from the sale and delivery of crude oil purchased either directly from producers or from others on the open market. These sales contracts generally settle with the physical delivery of crude oil to customers. In general, the sales prices referenced in the underlying contracts are market-based and may include pricing differentials for factors such as delivery location or crude oil quality.

Offshore Pipelines & Services

Revenue from our offshore pipelines is generally based upon a fixed fee per unit of volume gathered or transported multiplied by the volume delivered. Transportation fees are based either on contractual arrangements or tariffs regulated by the FERC. Revenue associated with these fee-based contracts and tariffs is recognized when volumes have been delivered.

Revenues from offshore platform services generally consist of demand fees and commodity charges. Revenues from offshore platform services are recognized in the period the services are provided. Demand fees represent charges to customers served by our offshore platforms regardless of the volume the customer actually delivers to the platform. Revenue from commodity charges is based on a fee per unit of volume delivered to the platform 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.

Petrochemical & Refined Products Services

Our propylene fractionation and butane isomerization facilities generate revenue through fee-based arrangements, which typically include a base-processing fee subject to adjustment for changes in power, fuel and labor costs, all of which are the primary costs of propylene fractionation and butane isomerization. Revenue resulting from such agreements is recognized in the period the services are provided. Revenues from our petrochemical pipeline transportation contracts are primarily based upon a fixed fee per volume transported (typically measured in gallons or pounds) multiplied by the volume delivered.

Our petrochemical marketing activities include the purchase and fractionation of refinery grade propylene obtained in the open market and generate revenues from the sale and delivery of products obtained through propylene fractionation. Revenue from these sales contracts is recognized when such products are delivered to customers. In general, we sell our petrochemical products at market-based prices, which may include pricing differentials for factors such as delivery location. Revenue from the production and sale of octane additives and high purity isobutylene is dependent on the sales price and volume of such commodities sold to customers. Revenue is recognized for sales transactions when the product is delivered.

Pipelines transporting refined products generate revenues through contracts and tariffs as customers are billed a fixed fee per barrel of liquids transported multiplied by the volume delivered. The fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Revenue associated with these fee-based contracts and tariffs is recognized when volumes have been delivered. Revenue from our refined products storage facilities is based on the number of days a customer has volumes in storage multiplied by a contractual storage fee. Under these contracts, revenue is recognized ratably over the length of the storage period. Revenue from product terminaling activities is recorded in the period such services are provided. Customers are typically billed a fee per unit of volume loaded.

Revenue is also generated from the provision of inland and offshore marine transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil, liquefied petroleum gas and other petroleum products via tow boats and tank barges. Under our marine services transportation contracts, revenue is recognized over the transit time of individual tows as determined on an individual contract basis, which is generally less than ten days in duration. Revenue from these contracts is typically based on set day rates or a set fee per cargo movement. The costs of fuel, substantially all of which is a pass through expense, and other specified operational fees and costs are directly reimbursed by the customer under most of these contracts.

Note 5. Equity-based Awards

An allocated portion of the fair value of EPCO's equity-based awards is charged to us under the ASA. The following table summarizes the compensation expense we recognized in connection with equity-based awards for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
Restricted common unit awards	$ 71.5	$ 57.0	$ 47.5
Unit option awards	0.8	1.3	3.1
Other (1)	0.5	1.7	0.3
Total	$ 72.8	$ 60.0	$ 50.9

(1) Primarily represents expense associated with unit appreciation rights ("UARs") and similar awards.

The fair value of equity-classified awards (e.g., restricted common unit and unit option awards) is amortized to earnings over the requisite service or vesting period. Compensation expense for liability-classified awards (e.g., UARs) is recognized over the requisite service or vesting period based on the fair value of the award remeasured at each reporting date. Liability-classified awards are settled in cash upon vesting.

At December 31, 2013, EPCO's significant long-term incentive plans applicable to us were the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan") and the 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) ("2008 Plan").

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 common units, phantom units and distribution equivalent rights ("DERs"). Up to 7,000,000 of our common units may be issued as awards under the 1998 Plan. After giving effect to awards granted under the 1998 Plan through December 31, 2013, a total of 1,155,630 additional common units could be issued.

In September 2013, our unitholders approved the third amendment and restatement of the 2008 Plan, which was also approved by the Audit and Conflicts Committee (the "AC Committee") of the Board of Directors of our general partner. The 2008 Plan (as amended and restated) is a long-term incentive plan under which any employee or consultant of EPCO, us or our affiliates that provides services to us, directly or indirectly, may receive incentive compensation awards in the form of options, restricted common units, phantom units, DERs, UARs, unit awards, other unit-based awards or substitute awards. Non-employee directors of our general partner may also participate in the 2008 Plan.

The 2008 Plan is administered by the AC Committee, which has significant authority thereunder to, among other things, (i) designate participants; (ii) determine the type or types of award(s) and the number of common units to be covered by any award; (iii) determine the terms and conditions of any award; and (iv) determine whether, to what extent and under what circumstances participants may settle, exercise, cancel or forfeit any award.

The maximum number of common units available for issuance under the 2008 Plan was 10,000,000 at December 31, 2013. This amount automatically increased under the terms of the 2008 Plan by 2,500,000 common units on January 1, 2014 and will continue to automatically increase annually on January 1 thereafter during the term of the 2008 Plan; provided, however, that in no event shall the maximum aggregate number exceed 35,000,000 common units. The 2008 Plan is effective until September 30, 2023 or, if earlier, until the time that all available common units under the 2008 Plan have been delivered to participants or the time of termination of the 2008 Plan by the Board of Directors of EPCO or by the AC Committee. After giving effect to awards granted under the 2008 Plan through December 31, 2013, a total of 4,348,820 additional common units could be issued.

Restricted Common Unit Awards

Restricted common unit awards allow recipients to acquire our common units (at no cost to the recipient apart from service or other conditions) once a defined vesting period expires, subject to customary forfeiture provisions. As used in the context of EPCO's long-term incentive plans, the term "restricted common unit" represents a time-vested unit. Restricted common unit awards generally vest at a rate of 25% per year beginning one year after the grant date. Such awards are non-vested until the required service period expires. Restricted common units are included in the number of common units presented on our Consolidated Balance Sheets.

The fair value of a restricted common unit award 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, over the requisite service or vesting period.

The following table presents information regarding restricted common unit awards for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted common units at December 31, 2010	3,561,614	$ 29.78
Granted (2)	1,414,630	$ 43.66
Vested	(924,108)	$ 31.54
Forfeited	(183,920)	$ 34.27
Restricted common units at December 31, 2011	3,868,216	$ 34.22
Granted (3)	1,588,738	$ 51.96
Vested	(1,316,603)	$ 34.80
Forfeited	(246,865)	$ 40.43
Restricted common units at December 31, 2012	3,893,486	$ 40.87
Granted (4)	1,774,526	$ 57.22
Vested	(1,885,348)	$ 34.97
Forfeited	(172,057)	$ 47.63
Restricted common units at December 31, 2013	3,610,607	$ 51.66

(1) Determined by dividing the aggregate grant date fair value of awards (before an allowance for forfeitures) by the number of awards issued.
(2) The aggregate grant date fair value of restricted common unit awards issued during 2011 was $61.8 million based on a grant date market price of our common units ranging from $40.54 to $44.67 per unit. An estimated annual forfeiture rate of 4.6% was applied to these awards.
(3) The aggregate grant date fair value of restricted common unit awards issued during 2012 was $82.5 million based on a grant date market price of our common units ranging from $51.92 to $53.54 per unit. An estimated annual forfeiture rate of 3.25% was applied to these awards.
(4) The aggregate grant date fair value of restricted common unit awards issued during 2013 was $101.5 million based on a grant date market price of our common units ranging from $57.11 to $63.48 per unit. An estimated annual forfeiture rate of 3.9% was applied to these awards.

Typically, each recipient is also entitled to nonforfeitable cash distributions equal to the product of the number of restricted common units outstanding for the participant and the cash distribution per unit paid to limited partners. Since these restricted common units are participating securities, such distributions are included in "Cash distributions paid to limited partners" as presented on our Statements of Consolidated Cash Flows.

The following table presents supplemental information regarding our restricted common unit awards for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
Cash distributions paid to restricted common unitholders	$ 10.6	$ 10.5	$ 9.6
Total intrinsic value of restricted common unit awards that vested during period	$ 109.9	$ 67.0	$ 39.1

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate $72.8 million at December 31, 2013, of which our allocated share of the cost is currently estimated to be $66.2 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 1.9 years.

Unit Option Awards

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options. These unit option awards are denominated in our common units. When issued, the exercise price of each unit option award may be no less than the market price of our common units on the date of grant. In general, unit option awards have a vesting period of four years from the date of grant and expire at the end of the calendar year following the year of vesting (e.g., an option vesting on May 29, 2012 would have expired on December 31, 2013). However, unit option awards only become exercisable at certain times during the calendar year following the year in which they vest (typically the months of February, May, August and November).

The fair value of each unit option award is estimated on the date of grant using a Black-Scholes option pricing model, which incorporates various assumptions including expected life of the option, risk-free interest rates, expected distribution yield of our common units, and expected price volatility of our common units. In general, our assumption of expected life of the options represents the period of time that the options are expected to be outstanding based on an analysis of our historical option activity. Our selection of risk-free interest rates is based on published yields for U.S. government securities with terms comparable to the expected life of the option. The expected distribution yield and unit price volatility assumptions are estimated based on several factors, which include an analysis of historical price volatility and distribution yield over a period of time equal to the expected life of the option. Compensation expense recorded in connection with unit option awards is based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

The following table presents unit option award activity for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Unit option awards at December 31, 2010 and 2011	3,753,420	$ 28.08		
Exercised	(742,280)	$ 30.77		
Forfeited	(250,000)	$ 27.45		
Unit option awards at December 31, 2012 (2,3)	2,761,140	$ 27.41		
Exercised	(736,140)	$ 29.95		
Unit option awards at December 31, 2013 (2,3)	2,025,000	$ 26.49	1.3	$ 57.0

(1) Aggregate intrinsic value reflects fully vested unit option awards at the date indicated.
(2) At December 31, 2013 and 2012, we were committed to issue 2,025,000 and 2,761,140, respectively, of our common units if all outstanding unit option awards were exercised. Option awards outstanding at December 31, 2013 include 1,330,000 awards that vested during 2013 and became exercisable beginning in February 2014. Of the remaining outstanding option awards at December 31, 2013, 695,000 will vest in 2014 and become exercisable in 2015.
(3) None of the unit option awards outstanding at December 31, 2013, 2012 and 2011 were exercisable.

In order to fund its unit option award-related obligations, EPCO may purchase common units at fair value either in the open market or directly from us. When employees exercise unit option awards, we reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

The following table presents supplemental information regarding our unit option awards during the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
Total intrinsic value of unit option awards exercised during period	$ 19.8	$ 14.6	$ --
Cash received from EPCO in connection with the exercise of unit option awards	$ 11.5	$ 10.2	$ --
Unit option award-related cash reimbursements to EPCO	$ 19.8	$ 14.0	$ --

For the EPCO group of companies, the unrecognized compensation cost associated with unit option awards was an aggregate $0.1 million at December 31, 2013. We expect to be allocated substantially all of the cost of these awards during the first quarter of 2014.

Note 6. Derivative Instruments, Hedging Activities and Fair Value Measurements

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with assets, liabilities and certain anticipated future transactions, we use derivative instruments such as futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

We are required to recognize derivative instruments at fair value as either assets or liabilities on our Consolidated Balance Sheets unless such instruments meet certain normal purchase/normal sale criteria. While all derivatives are required to be reported at fair value on the balance sheet, changes in fair value of derivative instruments are reported in different ways, depending on the nature and effectiveness of the hedging activities to which they relate. After meeting specified conditions, a qualified derivative may be designated as a total or partial hedge of:

§ Changes in the fair value of a recognized asset or liability, or an unrecognized firm commitment – In a fair value hedge, gains and losses for both the derivative instrument and the hedged item are recognized in income during the period of change.

§ Variable cash flows of a forecasted transaction – In a cash flow hedge, the effective portion of the hedge is reported in other comprehensive income (loss) and is reclassified into earnings when the forecasted transaction affects earnings.

An effective hedge relationship is one in which the change in fair value of a derivative instrument can be expected to offset 80% to 125% of the changes in fair value of a hedged item at inception and throughout the life of the hedging relationship. The effective portion of a hedge relationship is the amount by which the derivative instrument exactly offsets the change in fair value of the hedged item during the reporting period. Conversely, ineffectiveness represents the change in the fair value of the derivative instrument that does not exactly offset the change in the fair value of the hedged item. Any ineffectiveness associated with a hedge relationship is recognized in earnings immediately. Ineffectiveness can be caused by, among other things, changes in the timing of forecasted transactions or a mismatch of terms between the derivative instrument and the hedged item.

A contract designated as a cash flow hedge of an anticipated transaction that is not probable of occurring is immediately recognized in earnings.

Certain of our derivative instruments do not qualify for hedge accounting treatment; therefore, they are accounted for using mark-to-market accounting.

Interest Rate Hedging Activities

We may utilize interest rate swaps, forward starting swaps and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy is a component in controlling our overall cost of capital associated with such borrowings. Interest rate swaps exchange the stated interest rate paid on a notional amount of existing debt for the fixed or floating interest rate stipulated in the derivative instrument. Forward starting swaps hedge the expected underlying benchmark interest rates related to future issuances of debt.

The following table summarizes our portfolio of interest rate swaps at December 31, 2013:

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes AA	10 fixed-to-floating swaps	$ 750.0	1/2011 to 2/2016	3.2% to 1.2%	Fair value hedge
Undesignated swaps	6 floating-to-fixed swaps	$ 600.0	5/2010 to 7/2014	0.2% to 2.0%	Mark-to-market

During 2012, we settled 11 fixed-to-floating interest rate swaps having an aggregate notional amount of $800.0 million, resulting in gains totaling $37.7 million. As fair value hedges, the unamortized portion of these gains are a component of long-term debt (see Note 11) and are being amortized to earnings (as a decrease in interest expense) using the effective interest method over the forecasted hedged period of approximately three years.

In connection with the issuance of Senior Notes II and HH in March 2013 (see Note 11), we settled 16 forward starting swaps having an aggregate notional amount of $1.0 billion, that were outstanding at December 31, 2012, which resulted in cash losses totaling $168.8 million. These losses are a component of accumulated other comprehensive loss and are being amortized to earnings (as an increase in interest expense) over the forecasted hedge period of ten years using the effective interest method.

In connection with the issuance of senior notes during 2012, we settled 17 forward starting swaps having an aggregate notional amount of $850.0 million, resulting in cash losses totaling $185.5 million. These losses are reflected in accumulated other comprehensive loss and are being amortized to earnings (as an increase in interest expense) over the forecasted hedge period of ten years using the effective interest method.

In connection with the issuance of senior notes during 2011, we settled three forward starting swaps and two treasury locks having notional amounts of $250.0 million and $1.23 billion, respectively. The settlement of the three forward starting swaps resulted in cash losses totaling $5.8 million. As cash flow hedges, these losses are reflected in accumulated other comprehensive loss and are being amortized to earnings (as an increase in interest expense) over the forecasted hedge period of ten years using the effective interest method. The settlement of the two treasury locks resulted in cash losses totaling $17.4 million, which are being amortized to earnings (as an increase in interest expense) over the weighted-average forecasted hedge period of 25 years using the effective interest method.

Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, refined products and petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps, basis swaps and option contracts. The following table summarizes our portfolio of commodity derivative instruments outstanding at December 31, 2013 (volume measures as noted):

Derivative Purpose	Volume (1) Current (2)	Volume (1) Long-Term (2)	Accounting Treatment
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	7.0	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls)	1.1	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	0.4	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	3.1	0.1	Cash flow hedge
Natural gas marketing:			
Forecasted sales of natural gas (Bcf)	2.6	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	8.2	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	5.9	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	5.4	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.6	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.6	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	0.1	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	4.0	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	5.8	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	94.7	19.7	Mark-to-market
Refined products risk management activities (MMBbls) (4)	0.8	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	14.4	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is January 2015, May 2014 and October 2016, respectively.
(3) Current volumes include 27.5 Bcf of physical derivative instruments that are predominantly priced at a marked-based index plus a premium or minus a discount related to location differences.
(4) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

At December 31, 2013, our predominant commodity hedging strategies consisted of (i) hedging anticipated future purchases and sales of commodity products associated with transportation, storage and blending activities, (ii) hedging the fair value of commodity products held in inventory, (iii) hedging natural gas processing margins, and (iv) hedging octane enhancement margins. The following information summarizes these hedging strategies:

§ The objective of our anticipated future commodity purchases and sales hedging program is to hedge the margins of certain transportation, storage and blending activities by locking in purchases and sales prices through the use of forward contracts and derivative instruments.

§ The objective of our inventory hedging program is to hedge the fair value of commodity products currently held in inventory by locking in the sales price of the inventory through the use of forward contracts and derivative instruments.

§ The objective of our natural gas processing hedging program is to hedge an amount of gross margin associated with these activities. We achieve this objective by executing forward fixed-price sales of a portion of our expected equity NGL production using forward contracts and commodity derivative instruments. For certain natural gas processing contracts, the hedging of expected equity NGL production also involves the purchase of natural gas for plant thermal reduction, which is hedged by executing forward fixed-price purchases using forward contracts and derivative instruments.

§ The objective of our octane enhancement hedging program is to hedge an amount of gross margin associated with these activities. We achieve this objective by executing forward fixed-price sales of a portion of our expected octane enhancement product volumes and forward fixed-price purchases of NGL feedstocks using forward contracts and derivative instruments.

Certain basis swaps, basis spread options and other derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of commodity products. There is some uncertainty involved in the timing of these transactions often due to the development of more favorable profit opportunities or when spreads are insufficient to cover variable costs thus reducing the likelihood that the transactions will occur during the periods originally forecasted. In accordance with derivatives accounting guidance, these instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of the underlying assets. Due to volatility in commodity prices, any non-cash, mark-to-market earnings variability cannot be predicted.

Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items

The following table provides a balance sheet overview of our derivative assets and liabilities at the dates indicated:

	Asset Derivatives				Liability Derivatives			
	December 31, 2013		December 31, 2012		December 31, 2013		December 31, 2012	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments								
Interest rate derivatives	Other current assets	$ 20.2	Other current assets	$ 19.6	Other current liabilities	$ --	Other current liabilities	$ 175.4
Interest rate derivatives	Other assets	12.4	Other assets	25.6	Other liabilities	--	Other liabilities	--
Total interest rate derivatives		32.6		45.2		--		175.4
Commodity derivatives	Other current assets	30.9	Other current assets	45.3	Other current liabilities	46.5	Other current liabilities	35.4
Commodity derivatives	Other assets	--	Other assets	--	Other liabilities	0.3	Other liabilities	0.5
Total commodity derivatives		30.9		45.3		46.8		35.9
Total derivatives designated as hedging instruments		$ 63.5		$ 90.5		$ 46.8		$ 211.3
Derivatives not designated as hedging instruments								
Interest rate derivatives	Other current assets	$ --	Other current assets	$ --	Other current liabilities	$ 7.8	Other current liabilities	$ 12.2
Interest rate derivatives	Other assets	--	Other assets	--	Other liabilities	--	Other liabilities	5.0
Total interest rate derivatives		--		--		7.8		17.2
Commodity derivatives	Other current assets	7.6	Other current assets	15.7	Other current liabilities	5.5	Other current liabilities	8.9
Commodity derivatives	Other assets	2.8	Other assets	0.6	Other liabilities	2.8	Other liabilities	0.7
Total commodity derivatives		10.4		16.3		8.3		9.6
Total derivatives not designated as hedging instruments		$ 10.4		$ 16.3		$ 16.1		$ 26.8

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Certain of our commodity derivative instruments are subject to master netting arrangements or similar agreements. The following tables present our derivative instruments subject to such arrangements at the dates indicated:

Offsetting of Financial Assets and Derivative Assets

	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Amounts of Assets Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet: Financial Instruments	Gross Amounts Not Offset in the Balance Sheet: Cash Collateral Received	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)	(iv)	(v) = (iii) + (iv)
As of December 31, 2013:						
Commodity derivatives	$ 41.3	$ --	$ 41.3	$ (41.0)	$ --	$ 0.3
As of December 31, 2012:						
Commodity derivatives	$ 61.6	$ --	$ 61.6	$ (38.7)	$ (15.2)	$ 7.7

Offsetting of Financial Liabilities and Derivative Liabilities

	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Liabilities Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet: Financial Instruments	Gross Amounts Not Offset in the Balance Sheet: Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)	(iv)	(v) = (iii) + (iv)
As of December 31, 2013:						
Commodity derivatives	$ 55.1	$ --	$ 55.1	$ (41.0)	$ (9.3)	$ 4.8
As of December 31, 2012:						
Commodity derivatives	$ 45.5	$ --	$ 45.5	$ (38.7)	$ (4.3)	$ 2.5

Derivative assets and liabilities recorded on our Consolidated Balance Sheets are presented on a gross-basis and determined at the individual transaction level. This presentation method is applied regardless of whether the respective exchange clearing agreements, counterparty contracts or master netting agreements contain netting language often referred to as "rights of offset." Although derivative amounts are presented on a gross-basis, having rights of offset enable the settlement of a net as opposed to gross receivable or payable amount under a counterparty default or liquidation scenario.

Cash is paid and received as collateral under certain agreements, particularly for those associated with exchange transactions. For any cash collateral payments or receipts, corresponding assets or liabilities are recorded to reflect the variation margin deposits or receipts with exchange clearing brokers and customers. These balances are also presented on a gross-basis on our Consolidated Balance Sheets.

The tabular presentation above provides a means for comparing the gross amount of derivative assets and liabilities, excluding associated accounts payable and receivable, to the net amount that would likely be receivable or payable under a default scenario based on the existence of rights of offset in the respective derivative agreements. Any cash collateral paid or received is reflected in this table, but only to the extent that it represents variation margins. Any amounts associated with derivative prepayments or initial margins that are not influenced by the derivative asset or liability amounts or those that are determined solely on their volumetric notional amounts are excluded from this table.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following tables present the effect of our derivative instruments designated as fair value hedges on our Statements of Consolidated Operations for the periods indicated:

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative		
		For the Year Ended December 31,		
		2013	2012	2011
Interest rate derivatives	Interest expense	$ (13.1)	$ 2.7	$ 24.7
Commodity derivatives	Revenue	(0.1)	(6.4)	17.1
Total		$ (13.2)	$ (3.7)	$ 41.8

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item		
		For the Year Ended December 31,		
		2013	2012	2011
Interest rate derivatives	Interest expense	$ 12.8	$ (2.9)	$ (24.5)
Commodity derivatives	Revenue	(5.7)	19.1	(14.9)
Total		$ 7.1	$ 16.2	$ (39.4)

With respect to our derivative instruments designated as fair value hedges, amounts attributable to ineffectiveness and those excluded from the assessment of hedge effectiveness were not material to our consolidated financial statements during the years ended December 31, 2013, 2012 or 2011.

The following tables present the effect of our derivative instruments designated as cash flow hedges on our Statements of Consolidated Operations and Statements of Consolidated Comprehensive Income for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income (Loss) on Derivative (Effective Portion)		
	For the Year Ended December 31,		
	2013	2012	2011
Interest rate derivatives (1)	$ 6.6	$ (70.2)	$ (333.2)
Commodity derivatives – Revenue (2) (3)	(47.9)	31.0	(192.3)
Commodity derivatives – Operating costs and expenses (3)	1.0	(13.7)	(29.6)
Total	$ (40.3)	$ (52.9)	$ (555.1)

(1) The increase in other comprehensive loss in 2011 and 2012 was primarily due to the impact of decreases in forward London Interbank Offered Rates ("LIBOR") on our forward starting interest rate swap portfolio.
(2) The increase in other comprehensive loss in 2011 was primarily due to the impact of rising commodity prices on our cash flow hedges associated with physical future deliveries of NGLs, crude oil and refined products.
(3) The fair value of these derivative instruments would be reclassified to their respective locations on the Statement of Consolidated Operations upon settlement of the underlying derivative transactions, as appropriate.

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) to Income (Effective Portion)		
		For the Year Ended December 31,		
		2013	2012	2011
Interest rate derivatives	Interest expense	$ (29.2)	$ (16.2)	$ (6.3)
Commodity derivatives	Revenue	(22.4)	10.1	(218.4)
Commodity derivatives	Operating costs and expenses	0.3	(24.3)	(13.9)
Total		$ (51.3)	$ (30.4)	$ (238.6)

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion)		
		For the Year Ended December 31,		
		2013	2012	2011
Commodity derivatives	Revenue	$ 0.2	$ --	$ 0.2
Commodity derivatives	Operating costs and expenses	--	0.3	(0.3)
Total		$ 0.2	$ 0.3	$ (0.1)

Over the next twelve months, we expect to reclassify $32.4 million of losses attributable to interest rate derivative instruments from accumulated other comprehensive loss to earnings as an increase in interest expense. Likewise, we expect to reclassify $14.3 million of losses attributable to commodity derivative instruments from accumulated other comprehensive loss to earnings, $15.3 million as a decrease in revenue and $1.0 million as a decrease in operating costs and expenses.

The following table presents the effect of our derivative instruments not designated as hedging instruments on our Statements of Consolidated Operations for the periods indicated:

Derivatives Not Designated as Hedging Instruments	Location	Gain (Loss) Recognized in Income on Derivative		
		For the Year Ended December 31,		
		2013	2012	2011
Interest rate derivatives	Interest expense	$ (0.7)	$ (5.6)	$ (18.5)
Commodity derivatives	Revenue	7.3	22.7	39.9
Commodity derivatives	Operating costs and expense	--	(2.8)	(3.7)
Foreign currency derivatives	Other expense	--	--	(0.5)
Total		$ 6.6	$ 14.3	$ 17.2

Fair Value Measurements

Our fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk, in the principal market of the asset or liability at a specified measurement date. Recognized valuation techniques employ inputs such as contractual prices, quoted market prices or rates, operating costs, discount factors and business growth rates. These inputs may be either readily observable, corroborated by market data or generally unobservable. In developing our estimates of fair value, we endeavor to utilize the best information available and apply market-based data to the highest extent possible. Accordingly, we utilize valuation techniques (such as the market approach) that maximize the use of observable inputs and minimize the use of unobservable inputs.

A three-tier hierarchy has been established that classifies fair value amounts recognized in the financial statements based on the observability of inputs used to estimate such fair values. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). At each balance sheet reporting date, we categorize our financial assets and liabilities using this hierarchy.

The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

§ Level 1 fair values are based on quoted prices, which are available in active markets for identical assets or liabilities as of the measurement date. Active markets are defined as those in which transactions for identical assets or liabilities occur with sufficient frequency so as to provide pricing information on an ongoing basis (e.g., the New York Mercantile Exchange). Our Level 1 fair values consist of financial assets and liabilities such as exchange-traded commodity derivative instruments.

§ Level 2 fair values are based on pricing inputs other than quoted prices in active markets (as reflected in Level 1 fair values) and are either directly or indirectly observable as of the measurement date. Level 2 fair values include instruments that are valued using financial models or other appropriate valuation methodologies. Such financial models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, the time value of money, volatility factors, current market and contractual prices for the underlying instruments and other relevant economic measures. Substantially all of these assumptions (i) are observable in the marketplace throughout the full term of the instrument; (ii) can be derived from observable data; or (iii) are validated by inputs other than quoted prices (e.g., interest rate and yield curves at commonly quoted intervals). Our Level 2 fair values primarily consist of commodity derivative instruments such as forwards, swaps and other instruments transacted on an exchange or over-the-counter and interest rate derivative instruments. The fair values of these derivative instruments are based on observable price quotes for similar products and locations. The fair value of our interest rate derivatives are determined using financial models that incorporate the implied forward LIBOR yield curve for the same period as the future interest rate swap settlements.

§ Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect management's ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available to us in the circumstances, which might include our internally developed data. Level 3 inputs are typically used in connection with internally developed valuation methodologies where we make our best estimate of an instrument's fair value. Our Level 3 fair values primarily consist of ethane, propane, normal butane and natural gasoline-based contracts with terms greater than one year and certain options used to hedge natural gas storage inventory and transportation capacities. In addition, we often rely on price quotes from reputable brokers who publish price quotes on certain products and compare these prices to other reputable brokers for the same products in the same markets whenever possible. These prices, when combined with data from our commodity derivative instruments, are used in our models to determine the fair value of such instruments.

Transfers within the fair value hierarchy routinely occur for certain term contracts as prices and other inputs used for the valuation of future delivery periods become more observable with the passage of time. Other transfers are made periodically in response to changing market conditions that affect liquidity, price observability and other inputs used in determining valuations. We deem any such transfers to have occurred at the end of the quarter in which they transpired. There were no transfers between Level 1 and 2 for the years ended December 31, 2013 and 2012, respectively. See below for information related to transfers out of Level 3.

Recurring Fair Value Measurements

The following table sets forth, by level within the fair value hierarchy, the carrying values of our financial assets and liabilities at the dates indicated. These assets and liabilities are measured on a recurring basis and are classified based on the lowest level of input used to estimate their fair value. Our assessment of the relative significance of such inputs requires judgment.

	2013 Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Carrying Value at December 31, 2013**
Financial assets:				
Interest rate derivatives	$ --	$ 32.6	$ --	$ 32.6
Commodity derivatives	17.2	20.2	3.9	41.3
Total	$ 17.2	$ 52.8	$ 3.9	$ 73.9
Financial liabilities:				
Interest rate derivatives	$ --	$ 7.8	$ --	$ 7.8
Commodity derivatives	30.8	23.6	0.7	55.1
Total	$ 30.8	$ 31.4	$ 0.7	$ 62.9

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	2012 Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Carrying Value at December 31, 2012
Financial assets:				
Interest rate derivatives	$ --	$ 45.2	$ --	$ 45.2
Commodity derivatives	11.4	47.8	2.4	61.6
Total	$ 11.4	$ 93.0	$ 2.4	$ 106.8
Financial liabilities:				
Interest rate derivatives	$ --	$ 192.6	$ --	$ 192.6
Commodity derivatives	13.1	28.5	3.9	45.5
Total	$ 13.1	$ 221.1	$ 3.9	$ 238.1

The following table sets forth a reconciliation of changes in the overall fair values of our recurring Level 3 financial assets and liabilities for the periods indicated:

		For the Year Ended December 31,	
	Location	2013	2012
Financial asset (liability) balance, net, January 1		$ (1.5)	$ 0.4
Total gains (losses) included in:			
Net income (1)	Revenue	2.8	(2.9)
Other comprehensive income (loss)	Commodity derivative instruments – changes in fair value of cash flow hedges	(0.9)	10.1
Settlements		1.6	0.8
Transfers out of Level 3 (2)		1.2	(9.9)
Financial asset (liability) balance, net, December 31		$ 3.2	$ (1.5)

(1) There were $4.4 million and $1.9 million of unrealized gains included in these amounts for the years ended December 31, 2013 and 2012, respectively.
(2) Transfers out of Level 3 into Level 2 were due to shorter remaining transaction maturities falling inside of the Level 2 range at December 31, 2013 and 2012, respectively.

The following tables provide quantitative information about our recurring Level 3 fair value measurements at the dates indicated:

	Fair Value At December 31, 2013				
	Financial Assets	Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives:					
Crude oil	$ 3.9	$ 0.7	Discounted cash flow	Forward commodity prices	$89.55-$98.54/barrel

	Fair Value At December 31, 2012				
	Financial Assets	Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives:					
Crude oil	$ 2.4	$ 3.9	Discounted cash flow	Forward commodity prices	$75.62-$92.28/barrel

We believe forward commodity prices are the most significant unobservable inputs in determining our Level 3 recurring fair value measurements at December 31, 2013. In general, changes in the price of the underlying commodity increases or decreases the fair value of a commodity derivative depending on whether the derivative was purchased or sold. We generally expect changes in the fair value of our derivative instruments to be offset by corresponding changes in the fair value of our hedged exposures.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

We have a risk management policy that covers our Level 3 commodity derivatives. Governance and oversight of risk management activities for these commodities are provided by our CEO with guidance and support from a risk management committee ("RMC") that meets quarterly (or on a more frequent basis, if needed). Members of executive management attend the RMC meetings, which are chaired by the head of our commodities risk control group. This group is responsible for preparing and distributing daily reports and risk analysis to members of the RMC and other appropriate members of management. These reports include mark-to-market valuations with the one-day and month-to-date changes in fair values. This group also develops and validates the forward commodity price curves used to estimate the fair values of our Level 3 commodity derivatives. These forward curves incorporate published indexes, market quotes and other observable inputs to the extent available.

Nonrecurring Fair Value Measurements

The following table summarizes our non-cash impairment charges by segment during each of the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
NGL Pipelines & Services	$ 30.6	$ 16.3	$ 11.3
Onshore Natural Gas Pipelines & Services	--	29.2	10.4
Onshore Crude Oil Pipelines & Services	30.1	10.6	--
Offshore Pipelines & Services	18.0	4.0	5.5
Petrochemical & Refined Products Services	18.7	3.3	0.6
Total	$ 97.4	$ 63.4	$ 27.8

Non-cash impairment charges for 2013 include $4.8 million related to our investment in two offshore natural gas gathering systems owned by Neptune (see Note 9). This charge is a component of equity in income of unconsolidated affiliates on our Statements of Consolidated Operations. The remainder of the non-cash impairment charges for 2013, or $92.6 million, primarily relate to the abandonment of fixed assets classified as property, plant and equipment. These latter charges are a component of operating costs and expenses on our Statements of Consolidated Operations.

The following table summarizes our non-recurring fair value measurements for the year ended December 31, 2013:

		December 31, 2013 Fair Value Measurements Using			
	Carrying Value at December 31, 2013	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Impairment of long-lived assets disposed of other than by sale (1)	$ --	$ --	$ --	$ --	$ 79.4
Impairment of long-lived assets held and used	44.6	--	--	44.6	9.0
Impairment of long-lived assets to be disposed of by sale	0.6	--	--	0.6	9.0
Total					$ 97.4

(1) Our non-cash asset impairment charges for the year ended December 31, 2013 primarily represent the abandonment of crude oil and natural gas pipeline segments in Texas, Oklahoma and the Gulf of Mexico, certain refined products terminal assets in Texas, an NGL storage cavern in Arizona and an NGL fractionator and storage caverns in Ohio.

During the year ended December 31, 2012, we recorded $63.4 million of non-cash asset impairment charges primarily due to the abandonment of assets classified as property, plant and equipment. The following table summarizes our non-recurring fair value measurements for the year ended December 31, 2012:

		December 31, 2012 Fair Value Measurements Using			
	Carrying Value at December 31, 2012	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Impairment of long-lived assets disposed of other than by sale (1)	$ 0.8	$ --	$ --	$ 0.8	$ 56.5
Impairment of long-lived assets held and used	2.2	--	--	2.2	2.6
Impairment of long-lived assets to be disposed of by sale	--	--	--	--	4.3
Total					$ 63.4

(1) Our non-cash asset impairment charges for the year ended December 31, 2012 primarily represent the abandonment of crude oil and natural gas pipeline segments in Texas and the Gulf of Mexico.

As presented in the preceding tables, our estimated fair values were based on management's expectation of the market values for such assets based on their knowledge and experience in the industry (a Level 3 type measure involving significant unobservable inputs). In many cases, there are no active markets (Level 1) or other similar recent transactions (Level 2) to compare to. Our assumptions used in such analyses are based on the nonfinancial assets' highest and best use, which includes estimated probabilities where multiple cash flow outcomes are possible.

When probability weights are used, they are generally obtained from business management personnel having oversight responsibilities for the assets being tested. Key commercial assumptions (e.g., anticipated operating margins, throughput or processing volume growth rates, timing of cash flows, etc.) that represent Level 3 unobservable inputs and test results are reviewed and certified by members of senior management.

Other Fair Value Information

The carrying amounts of cash and cash equivalents (including restricted cash balances), accounts receivable, commercial paper notes and accounts payable approximate their fair values based on their short-term nature. The estimated total fair value of our fixed-rate debt obligations was $18.4 billion and $18.42 billion at December 31, 2013 and 2012, respectively. The aggregate carrying value of these debt obligations was $17.36 billion and $16.18 billion at December 31, 2013 and 2012, respectively. These values are based on quoted market prices for such debt or debt of similar terms and maturities (Level 2), our credit standing and the credit standing of our counterparties. Changes in market rates of interest affect the fair value of our fixed-rate debt. The carrying values of our variable-rate long-term debt obligations approximate their fair values since the associated interest rates are market-based. We do not have any long-term investments in debt or equity securities recorded at fair value.

Note 7. Inventories

Our inventory amounts by product type were as follows at the dates indicated:

	December 31,	
	2013	2012
NGLs	$ 593.8	$ 594.3
Petrochemicals and refined products	395.1	304.5
Crude oil	42.6	119.4
Natural gas	61.6	70.2
Total	$ 1,093.1	$ 1,088.4

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In those instances where we take ownership of inventory volumes through percent-of-liquids contracts and similar arrangements (as opposed to outright purchases from third parties for cash), these volumes are valued at market-based prices during the month in which they are acquired.

Due to fluctuating commodity prices, we recognize lower of cost or market adjustments when the carrying value of our available-for-sale inventories exceeds their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized. To the extent our commodity hedging strategies address inventory-related price risks and are successful, these inventory valuation adjustments are mitigated or offset. See Note 6 for a description of our commodity hedging activities.

The following table presents our total cost of sales amounts and lower of cost or market adjustments for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
Cost of sales (1)	$ 40,770.2	$ 36,015.5	$ 38,292.6
Lower of cost or market adjustments	$ 18.5	$ 22.1	$ 9.5

(1) Cost of sales is a component of "Operating costs and expenses," as presented on our Statements of Consolidated Operations. Year-to-year fluctuations in these amounts are primarily due to changes in energy commodity prices and sales volumes associated with our marketing activities.

Note 8. Property, Plant and Equipment

The historical costs of our property, plant and equipment and related accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	December 31, 2013	December 31, 2012
Plants, pipelines and facilities (1)	3-45 (6)	$ 27,540.4	$ 25,382.4
Underground and other storage facilities (2)	5-40 (7)	2,101.8	1,826.3
Platforms and facilities (3)	20-31	659.6	635.2
Transportation equipment (4)	3-10	138.9	136.2
Marine vessels (5)	15-30	744.8	695.0
Land		176.6	167.2
Construction in progress		2,655.5	2,113.1
Total		34,017.6	30,955.4
Less accumulated depreciation		7,071.0	6,109.0
Property, plant and equipment, net		$ 26,946.6	$ 24,846.4

(1) Plants and pipelines include processing plants; NGL, natural gas, crude oil and petrochemical and refined products pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment and related assets.
(2) Underground and other storage facilities include underground product storage caverns; above ground storage tanks; water wells and related assets.
(3) Platforms and facilities include offshore platforms and related facilities and other associated assets located in the Gulf of Mexico.
(4) Transportation equipment includes tractor-trailer tank trucks and other vehicles and similar assets used in our operations.
(5) Marine vessels include tow boats, barges and related equipment used in our marine transportation business.
(6) In general, the estimated useful lives of major assets within this category are: processing plants, 20-35 years; pipelines and related equipment, 5-45 years; terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings, 20-40 years; and laboratory and shop equipment, 5-35 years.
(7) In general, the estimated useful lives of assets within this category are: underground storage facilities, 5-35 years; storage tanks, 10-40 years; and water wells, 5-35 years.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table summarizes our depreciation expense and capitalized interest amounts for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
Depreciation expense (1)	$ 1,012.4	$ 900.5	$ 776.6
Capitalized interest (2)	133.0	116.8	106.7

(1) Depreciation expense is a component of "Costs and expenses" as presented on our Statements of Consolidated Operations.

(2) We capitalize interest costs incurred on funds used to construct property, plant and equipment while the asset is in its construction phase. The capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset's estimated useful life as a component of depreciation expense. When capitalized interest is recorded, it reduces interest expense from what it would be otherwise.

In December 2011, we sold our equity interests in Crystal Holding L.L.C. ("Crystal"), which owns natural gas storage facilities and associated pipelines located in Mississippi for $547.8 million in cash (net of working capital adjustments). We recorded a $129.1 million gain on the sale of Crystal. The net carrying value of our investment in Crystal was approximately $411.9 million, of which $356.2 million was the total net carrying value of Crystal's property, plant and equipment. We determined that the financial results of Crystal did not meet the criteria to be classified as discontinued operations. We enter into commercial contracts and have operational arrangements with the Petal and Hattiesburg natural gas storage facilities, which are adjacent to and currently share operating assets with our Petal, Mississippi NGL storage facility.

In March 2013, we sold the Stratton Ridge-to-Mont Belvieu segment of the Seminole Pipeline, along with a related storage cavern, for cash proceeds of $86.9 million. As a result, net income for the year ended December 31, 2013 includes a $52.5 million gain attributable to the sale of these assets. The Seminole Pipeline remains connected to our Mont Belvieu complex through a newly constructed NGL pipeline that we own.

Asset Retirement Obligations

We record AROs in connection with legal requirements to perform specified retirement activities under contractual arrangements and/or governmental regulations. Our contractual AROs primarily result from right-of-way agreements associated with our pipeline operations and real estate leases associated with our plant sites. In addition, we record AROs in connection with governmental regulations associated with the abandonment or retirement of (i) above-ground brine storage pits, (ii) offshore Gulf of Mexico platform and pipeline assets and (iii) certain marine vessels. We also record AROs in connection with regulatory requirements associated with the renovation or demolition of certain assets containing hazardous substances such as asbestos. We typically fund our ARO obligations using cash flow from operations.

Property, plant and equipment at December 31, 2013 and 2012 includes $37.4 million and $40.3 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

The following table presents information regarding our AROs for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
Balance at beginning of period	$ 105.2	$ 112.0	$ 97.1
Liabilities incurred	1.7	1.7	0.7
Liabilities settled	(14.2)	(27.8)	(7.3)
Revisions in estimated cash flows	(8.6)	13.7	15.0
Accretion expense	6.1	5.6	6.5
Balance at end of period	$ 90.2	$ 105.2	$ 112.0

The following table presents our forecast of accretion expense for the periods indicated:

2014	2015	2016	2017	2018
$ 6.1	$ 6.5	$ 6.9	$ 7.4	$ 8.0

Certain of our unconsolidated affiliates have AROs recorded at December 31, 2013 and 2012 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our consolidated financial statements.

Note 9. Investments in Unconsolidated Affiliates

The following table presents our investments in unconsolidated affiliates by business segment at the dates indicated. Unless noted otherwise, we account for these investments using the equity method.

	Ownership Interest at December 31, 2013	December 31, 2013	December 31, 2012
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C. (“VESCO”)	13.1%	$ 27.6	$ 29.6
K/D/S Promix, L.L.C. (“Promix”)	50%	45.4	46.9
Baton Rouge Fractionators LLC (“BRF”)	32.2%	19.5	20.2
Skelly-Belvieu Pipeline Company, L.L.C. (“Skelly-Belvieu”)	50%	40.8	38.2
Texas Express Pipeline LLC (“Texas Express”)	35%	339.9	144.4
Texas Express Gathering LLC (“TEG”)	45%	37.8	20.9
Front Range Pipeline LLC (“Front Range”)	33.3%	134.5	24.4
Onshore Natural Gas Pipelines & Services:			
White River Hub, LLC (“White River Hub”)	50%	24.2	24.9
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC (“Seaway”)	50%	940.7	341.4
Eagle Ford Pipeline LLC (“Eagle Ford Crude Oil Pipeline”)	50%	224.5	152.4
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. (“Poseidon”)	36%	41.7	47.3
Cameron Highway Oil Pipeline Company (“Cameron Highway”)	50%	207.7	220.0
Deepwater Gateway, L.L.C. (“Deepwater Gateway”)	50%	84.5	90.0
Neptune Pipeline Company, L.L.C. (“Neptune”)	25.7%	38.7	46.8
Southeast Keathley Canyon Pipeline Company, L.L.C. (“SEKCO”)	50%	159.2	74.9
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC (“BRPC”)	30%	7.6	8.5
Centennial Pipeline LLC (“Centennial”)	50%	60.1	60.8
Other (1)	Various	2.7	3.0
Total		$ 2,437.1	$ 1,394.6

(1) Other unconsolidated affiliates include a 50% interest in a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas and a 25% interest in a company that provides logistics communications solutions between petroleum pipelines and their customers.

NGL Pipelines & Services

The principal business activity of each investee included in our NGL Pipelines & Services segment is described as follows:

- VESCO owns a natural gas processing facility in south Louisiana and a related gathering system that gathers natural gas from certain offshore developments for delivery to its natural gas processing facility.

- Promix owns an NGL fractionation facility and related storage caverns located in south Louisiana. The facility receives mixed NGLs via pipeline from natural gas processing plants located in southern Louisiana and along the Mississippi Gulf Coast. In addition, Promix owns an NGL gathering system that gathers mixed NGLs from processing plants in southern Louisiana for its fractionator.

§ BRF owns an NGL fractionation facility located in south Louisiana that receives mixed NGLs from natural gas processing plants located in Alabama, Mississippi and southern Louisiana.

§ Skelly-Belvieu owns a pipeline that transports mixed NGLs from Skellytown, Texas to Mont Belvieu, Texas. The Skelly-Belvieu Pipeline receives NGLs through a pipeline interconnect with our Mid-America Pipeline System in Skellytown, Texas.

§ Texas Express owns an NGL pipeline that extends from Skellytown, Texas to our NGL fractionation and storage complex at Mont Belvieu, Texas. This pipeline commenced operations in November 2013. Mixed NGL volumes from the Rocky Mountains, Permian Basin and Mid-Continent regions are delivered to the pipeline via an interconnect with our Mid-America Pipeline System near Skellytown. The pipeline also transports mixed NGL volumes from two gathering systems owned by TEG to Mont Belvieu. In addition, mixed NGL volumes from the Denver-Julesburg supply basin are transported to the pipeline using the Front Range pipeline, which commenced operations in February 2014.

§ TEG owns two NGL gathering systems that deliver volumes to the Texas Express Pipeline. These gathering systems commenced operations in November 2013. The Elk City gathering system currently gathers mixed NGLs from natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and western Oklahoma. The North Texas gathering system currently gathers mixed NGLs from natural gas processing plants in the Barnett Shale production area in North Texas. Enbridge serves as operator of these two NGL gathering systems.

§ Front Range owns an NGL pipeline that transports mixed NGLs from natural gas processing plants located in the Denver-Julesburg Basin in Colorado to an interconnect with our Texas Express pipeline and Mid-America Pipeline System at Skellytown, Texas. The Front Range pipeline commenced operations in February 2014.

Onshore Natural Gas Pipelines & Services

White River Hub owns a natural gas hub facility serving producers in the Piceance Basin of northwest Colorado. The facility enables producers to access six interstate natural gas pipelines.

Onshore Crude Oil Pipelines & Services

The principal business activity of each investee included in our Onshore Crude Oil Pipelines & Services segment is described as follows:

§ Seaway owns a pipeline that connects the Cushing, Oklahoma hub with markets in Southeast Texas. The Seaway Pipeline is comprised of the Longhaul System, the Freeport System and the Texas City System. The Cushing hub is a major industry trading hub and price settlement point for West Texas Intermediate on the New York Mercantile Exchange.

The Longhaul System provides north-to-south transportation of crude oil from the Cushing hub to Seaway's Jones Creek terminal near Freeport, Texas and our terminal located near Katy, Texas. In early 2012, Seaway undertook a reversal of the flow of its Longhaul System and began providing north-to-south transportation service in May 2012. Previously, this pipeline was used to transport crude oil in the opposite direction from the Jones Creek terminal to the Cushing hub.

We expect to complete a looping project involving our Longhaul System in mid-year 2014. This expansion project entails the construction of an additional pipeline that will transport crude oil southbound from the Cushing hub to the Jones Creek terminal.

The Freeport System consists of a ship unloading dock, three pipelines and other related facilities that transport crude oil from Freeport, Texas to the Jones Creek terminal. The Texas City System consists of a ship unloading dock, storage tanks, various pipelines and other related facilities that deliver crude oil from Texas City, Texas to Galena Park, Texas and other nearby locations. The Freeport System and Texas City

System make only intrastate movements. Seaway also owns storage tanks at the Jones Creek terminal, which are connected to the Longhaul System.

§ Eagle Ford Pipeline LLC owns a crude oil pipeline that transports crude oil and condensate for producers in South Texas. The system consists of a crude oil and condensate pipeline extending from Gardendale, Texas in LaSalle County to Three Rivers, Texas in Live Oak County and continuing on to Corpus Christi, Texas. The system also includes a pipeline segment extending from Three Rivers to an interconnect with our South Texas Crude Oil Pipeline System in Wilson County. This system, which commenced operations in July 2013, includes a marine terminal facility at Corpus Christi and storage capacity across the system. Plains All American Pipeline, L.P. ("Plains"), our joint venture partner in the pipeline, serves as operator of the system.

Offshore Pipelines & Services

The principal business activity of each investee included in our Offshore Pipelines & Services segment is described as follows:

§ Poseidon owns a crude oil pipeline that transports crude oil production from the outer continental shelf and deepwater areas of the Gulf of Mexico offshore Louisiana to onshore facilities in south Louisiana.

§ Cameron Highway owns a crude oil pipeline that transports crude oil production from deepwater areas of the Gulf of Mexico, primarily the Green Canyon area, for delivery to refineries and terminals in southeast Texas.

§ Deepwater Gateway owns an offshore platform that processes crude oil and natural gas from production fields located in the South Green Canyon area of the Gulf of Mexico.

§ Neptune owns the Manta Ray Offshore Gathering System and Nautilus System, both of which are natural gas pipeline systems located in the Gulf of Mexico. As a result of declining pipeline throughput volumes forecast for these systems in 2014 and future years, we recorded a $4.8 million non-cash impairment charge related to our equity investment in Neptune in 2013.

§ SEKCO, upon construction, will own a crude oil gathering pipeline serving the Lucius oil and gas field located in the southern Keathley Canyon area of the deepwater central Gulf of Mexico. The SEKCO Oil Pipeline is expected to begin service during the third quarter of 2014.

Petrochemical & Refined Products Services

The principal business activity of each significant investee included in our Petrochemical & Refined Products Services segment is described as follows:

§ BRPC owns a propylene fractionation facility located in south Louisiana that fractionates refinery grade propylene into chemical grade propylene.

§ Centennial owns an interstate refined products pipeline that extends from an origination facility in Beaumont, Texas, to Bourbon, Illinois. Centennial also owns a refined products storage terminal located near Creal Springs, Illinois.

Other Investments

Liquidation of Investment in Energy Transfer Equity

The Other Investments segment included our noncontrolling ownership interest in Energy Transfer Equity, which was accounted for using the equity method until January 18, 2012. Since our ownership interest in Energy Transfer Equity exceeded 3% of its total ownership interests throughout 2011, we accounted for our investment in Energy Transfer Equity using the equity method and included gains from the partial sale of this investment in operating income. During 2011, we sold a total of 9,672,576 Energy Transfer Equity common units for net cash proceeds of $375.2 million and recorded gains of $27.2 million on the sales. At December 31, 2011, we owned 29,303,514 common units of Energy Transfer Equity representing 13.1% of its limited partner interests.

On January 18, 2012, we sold 22,762,636 of these common units in a private transaction, which generated cash proceeds of $825.1 million. As a result of this transaction, our ownership interest in Energy Transfer Equity was reduced below 3%, and we discontinued using the equity method to account for this investment and began accounting for it as an investment in available-for-sale equity securities. The remaining 6,540,878 units were sold systematically through April 27, 2012 and generated additional total cash proceeds of $270.2 million. In the aggregate, the liquidation of this investment during 2012 resulted in $68.8 million of gains that are a component of "Other income" on our Statements of Consolidated Operations.

All activities included in the Other Investments business segment ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our investment in Energy Transfer Equity. See Note 13 for information regarding our business segments.

Equity Earnings and Excess Cost

The following table presents our equity in income (loss) of unconsolidated affiliates by business segment for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
NGL Pipelines & Services	$ 15.7	$ 15.9	$ 21.8
Onshore Natural Gas Pipelines & Services	3.8	4.4	5.5
Onshore Crude Oil Pipelines & Services	140.3	32.6	(4.1)
Offshore Pipelines & Services	29.8	26.9	27.1
Petrochemical & Refined Products Services (1)	(22.3)	(17.9)	(18.7)
Other Investments (2)	--	2.4	14.8
Total	$ 167.3	$ 64.3	$ 46.4

(1) Losses are primarily attributable to our investment in Centennial. As a result of a trend in declining earnings, we estimated the fair value of this equity-method investment during each of the last three fiscal years. Our estimates, based on a combination of the market and income approaches, indicate that the fair value of this investment remains substantially in excess of its carrying value.

(2) With respect to the year ended December 31, 2012, the amount presented reflects our equity in the income of Energy Transfer Equity from January 1, 2012 to January 18, 2012.

On occasion, the price we pay to acquire an ownership interest in a company exceeds the underlying carrying value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our investments in Promix, Skelly-Belvieu, Seaway, Poseidon, Cameron Highway, Centennial and La Porte at December 31, 2013. These excess cost amounts are attributable to the fair value of the underlying tangible assets of these entities exceeding their respective book carrying values at the time of our acquisition of ownership interests in these entities. We amortize such excess cost amounts as a reduction to equity earnings in a manner similar to depreciation.

The following table presents the unamortized excess cost amounts by business segment at the dates indicated:

	December 31,	
	2013	2012
NGL Pipelines & Services	$ 27.7	$ 28.9
Onshore Crude Oil Pipelines & Services	17.8	18.5
Offshore Pipelines & Services	10.0	13.6
Petrochemical & Refined Products Services	2.6	2.7
Total	$ 58.1	$ 63.7

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents our amortization of excess cost amounts by business segment for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
NGL Pipelines & Services	$ 1.2	$ 1.0	$ 1.0
Onshore Crude Oil Pipelines & Services	0.7	0.7	0.7
Offshore Pipelines & Service	1.3	1.2	1.2
Petrochemical & Refined Products Services	0.1	0.2	0.1
Other Investments (1)	--	0.3	31.5
Total	$ 3.3	$ 3.4	$ 34.5

(1) Reflects amortization of excess cost amounts related to our investment in Energy Transfer Equity through January 18, 2012, which is the date we ceased using the equity method to account for this investment.

The following table presents forecasted amortization of excess cost amounts for the years indicated.

2014	2015	2016	2017	2018
$ 3.2	$ 3.2	$ 3.2	$ 3.2	$ 3.2

Summarized Combined Financial Information of Unconsolidated Affiliates

Combined balance sheet information for the last two years and results of operations data for the last three years for our unconsolidated affiliates are summarized in the following table (all data presented on a 100% basis):

	At December 31,	
	2013	2012
Balance Sheet Data:		
Current assets	$ 266.6	$ 254.7
Property, plant and equipment, net	5,735.6	2,911.3
Other assets	24.9	3.2
Total assets	$ 6,027.1	$ 3,169.2
Current liabilities	$ 494.6	$ 276.3
Other liabilities	309.0	272.1
Combined equity	5,223.5	2,620.8
Total liabilities and combined equity	$ 6,027.1	$ 3,169.2

	For the Year Ended December 31,		
	2013	2012	2011
Income Statement Data:			
Revenues	$ 947.4	$ 670.1	$ 9,119.9
Operating income	423.9	213.7	1,393.4
Net income	382.6	174.9	458.1

Income statement data presented for the year ended December 31, 2011 includes amounts related to Energy Transfer Equity (prior to our treating this investment as an available-for-sale security as previously noted) and Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp. (collectively "Evangeline," prior to our acquisition of their remaining ownership interests in June 2012).

Other

The credit agreements of Poseidon and Centennial restrict their ability to pay cash dividends if a default or event of default (as defined in each credit agreement) has occurred and is continuing at the time such payments are scheduled to be paid. These businesses were in compliance with the terms of their credit agreements at December 31, 2013.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 10. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets by business segment at the dates indicated:

	December 31, 2013			December 31, 2012		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 340.8	$ (165.7)	$ 175.1	$ 340.8	$ (147.6)	$ 193.2
Contract-based intangibles	281.3	(171.2)	110.1	284.6	(157.2)	127.4
Segment total	622.1	(336.9)	285.2	625.4	(304.8)	320.6
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,163.6	(281.2)	882.4	1,163.6	(250.0)	913.6
Contract-based intangibles	466.1	(330.7)	135.4	466.1	(311.8)	154.3
Segment total	1,629.7	(611.9)	1,017.8	1,629.7	(561.8)	1,067.9
Onshore Crude Oil Pipelines & Services:						
Customer relationship intangibles	10.7	(6.3)	4.4	10.7	(4.9)	5.8
Contract-based intangibles	0.4	(0.3)	0.1	0.4	(0.3)	0.1
Segment total	11.1	(6.6)	4.5	11.1	(5.2)	5.9
Offshore Pipelines & Services:						
Customer relationship intangibles	203.9	(150.0)	53.9	203.9	(138.5)	65.4
Contract-based intangibles	1.2	(0.4)	0.8	1.2	(0.4)	0.8
Segment total	205.1	(150.4)	54.7	205.1	(138.9)	66.2
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.3	(38.2)	66.1	104.3	(33.4)	70.9
Contract-based intangibles	39.9	(6.0)	33.9	41.2	(5.9)	35.3
Segment total	144.2	(44.2)	100.0	145.5	(39.3)	106.2
Total all segments	$ 2,612.2	$ (1,150.0)	$ 1,462.2	$ 2,616.8	$ (1,050.0)	$ 1,566.8

The following table presents the amortization expense of our intangible assets by business segment for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
NGL Pipelines & Services	$ 36.4	$ 39.7	$ 41.1
Onshore Natural Gas Pipelines & Services	50.1	63.4	77.1
Onshore Crude Oil Pipelines & Services	1.4	0.9	0.4
Offshore Pipelines & Services	11.5	11.3	11.2
Petrochemical & Refined Products Services	6.2	10.4	17.2
Total	$ 105.6	$ 125.7	$ 147.0

The following table presents our forecast of amortization expense associated with existing intangible assets for the years indicated:

2014	2015	2016	2017	2018
$ 93.8	$ 85.6	$ 81.2	$ 85.7	$ 89.0

In general, our intangible assets fall within two categories – customer relationship and contract-based intangible assets. The values assigned to such intangible assets are amortized to earnings using either (i) a straight-line approach or (ii) other methods that closely resemble the pattern in which the economic benefits of associated resource bases are estimated to be consumed or otherwise used, as appropriate.

Customer relationship intangible assets. Customer relationship intangible assets represent the estimated economic value assigned to certain relationships acquired in connection with business combinations and asset purchases whereby (i) we acquired information about or access to customers and now have the ability to provide services to them and (ii) the customers now have the ability to make direct contact with us. Customer relationships may arise from contractual arrangements (such as service contracts) and through means other than contracts, such as through regular contact by sales or service representatives.

At December 31, 2013, the carrying value of our portfolio of customer relationship intangible assets was $1.18 billion. The following information summarizes the significant components of this category of intangible assets:

§ State Line and Fairplay customer relationships – We acquired these customer relationships in connection with our acquisition of the State Line and Fairplay natural gas gathering systems in May 2010. The carrying values of these intangible assets at December 31, 2013 are presented in the following table:

	Gross Value	Accumulated Amortization	Carrying Value
State Line natural gas gathering customer relationships (1)	$ 675.0	$ (62.2)	$ 612.8
Fairplay natural gas gathering customer relationships (1)	116.6	(24.2)	92.4
Fairplay natural gas processing customer relationships (2)	103.4	(21.5)	81.9
Total	$ 895.0	$ (107.9)	$ 787.1

(1) These natural gas gathering customer relationship intangible assets are a component of our Onshore Natural Gas Pipelines & Services business segment.
(2) The Fairplay natural gas processing customer relationship intangible assets are a component of our NGL Pipelines & Services business segment.

In this context, a customer relationship is broadly defined as a relationship between the natural gas gathering system and the production fields from which it gathers natural gas. Natural gas gathering systems require a significant investment, both in terms of initial construction costs and ongoing maintenance. Ownership of the gathering system creates a level of access to producers in a field analogous to having a franchise over a particular area. Efficient operation of the gathering system helps to support commercial relationships with existing producers and provides us with opportunities to establish relationships with new ones. The duration of such customer relationships are limited by the estimated economic life of the underlying resource basins.

The economic value we attributed to customer relationships acquired with the State Line and Fairplay systems was estimated using recognized business valuation techniques based on several key assumptions, which include assumptions regarding the renewal of existing gathering and processing contracts and the longevity of the underlying natural gas resource basins. In general, natural gas is gathered on the State Line and Fairplay systems under long-term contracts, which include acreage dedications and volumetric commitments from certain natural gas producers. In addition, certain contracts related to the Fairplay system include natural gas processing services. Based on our experience as a provider of natural gas gathering and processing services, we anticipate the acquired customer relationships to extend well beyond the discrete term of existing contracts.

Customer relationship intangibles related to the State Line system have an estimated economic life of 27 years through 2037. The natural gas gathering and processing customer relationships associated with the Fairplay system have an estimated economic life of 23 years through 2033. Amortization expense attributable to these customer relationships is recorded using the units-of-production method based on gathering volumes. This method of amortization allows for expense to be recorded in a manner that closely resembles the pattern in which we benefit from natural gas gathering and processing services provided to customers.

§ San Juan Gathering System customer relationships – We acquired these customer relationships in connection with a merger transaction completed in September 2004. At December 31, 2013, the carrying value of this group of intangible assets was $159.7 million. These intangible assets are being amortized to earnings over their estimated economic life of 35 years through 2039. Amortization expense attributable to these customer relationships is recorded using a method that closely resembles the pattern in which the economic benefits of the underlying natural gas resource basins are expected to be consumed or otherwise used.

§ Offshore Pipeline & Platform customer relationships – We acquired these customer relationships in connection with a merger transaction completed in September 2004. At December 31, 2013, the carrying value of this group of intangible assets was $53.9 million. These intangible assets are being amortized to earnings over their estimated economic lives, which range from 11 to 33 years (i.e., through 2015 to 2037). Amortization expense attributable to these customer relationships is recorded using a method that closely resembles the pattern in which the economic benefits of the underlying crude oil and natural gas resource basins are expected to be consumed or otherwise used.

§ Encinal natural gas processing customer relationships – We acquired these customer relationships in connection with our acquisition of certain South Texas assets in 2006. At December 31, 2013, the carrying value of this group of intangible assets was $56.9 million. These intangible assets are being amortized to earnings over their estimated economic life of 20 years through 2026. Amortization expense attributable to these customer relationships is recorded using a method that closely resembles the pattern in which the economic benefit of the underlying natural gas resource basins are expected to be consumed or otherwise used.

Contract-based intangible assets. Contract-based intangible assets represent specific commercial rights we acquired in connection with business combinations or asset purchases. At December 31, 2013, the carrying value of our contract-based intangible assets was $280.3 million. The following information summarizes the significant components of this category of intangible assets:

§ Jonah natural gas gathering agreements – These intangible assets represent the value attributed to certain natural gas gathering contracts on the Jonah Gathering System that were acquired by TEPPCO in 2001. At December 31, 2013, the carrying value of this group of intangible assets was $89.4 million. These intangible assets are being amortized to earnings over their estimated economic life of 40 years through 2041. Amortization expense attributable to these intangible assets is recorded using a units-of-production method based on gathering volumes.

§ Shell Processing Agreement – This margin-band/keepwhole natural gas processing agreement grants us the right to process Shell Oil Company's (or its assignee's) current and future natural gas production from the state and federal waters of the Gulf of Mexico. We acquired the Shell Processing Agreement in connection with our purchase of certain U.S. Gulf Coast midstream energy assets from Shell Oil Company in 1999. At December 31, 2013, the carrying value of this intangible asset was $61.7 million. This intangible asset is being amortized to earnings on a straight-line basis over its estimated economic life of 20 years through 2019.

§ San Juan basin natural gas gathering agreements – These intangible assets represent the value attributed to certain natural gas gathering contracts with producers in the San Juan basin that were acquired by TEPPCO in 2002. At December 31, 2013, the carrying value of these intangible assets was $44.9 million. These intangible assets are being amortized to earnings over their estimated economic life of 20 years through 2021. Amortization expense attributable to these intangible assets is recorded using a units-of-production method based on gathering volumes.

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing at the end of each fiscal year, and more frequently, if circumstances indicate it is probable that the fair value of goodwill is below its carrying amount. The following table presents changes in the carrying amount of goodwill during the periods indicated:

	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Consolidated Total
Balance at December 31, 2010 (1)	$ 341.2	$ 311.1	$ 311.2	$ 82.1	$ 1,062.1	$ 2,107.7
Goodwill adjustment (2)	--	--	--	--	(0.6)	(0.6)
Goodwill related to the sale of assets (3)	--	(14.8)	--	--	--	(14.8)
Balance at December 31, 2011 (1)	341.2	296.3	311.2	82.1	1,061.5	2,092.3
Reclassification to assets held for sale	--	--	--	--	(5.5)	(5.5)
Balance at December 31, 2012 (1)	341.2	296.3	311.2	82.1	1,056.0	2,086.8
Goodwill related to the sale of assets	--	--	(6.1)	--	(0.7)	(6.8)
Balance at December 31, 2013 (1)	$ 341.2	$ 296.3	$ 305.1	$ 82.1	$ 1,055.3	$ 2,080.0

(1) The total carrying amount of goodwill at December 31, 2010 is net of $1.3 million of accumulated impairment charges incurred prior to 2010. No goodwill impairment charges were recorded during the three years ended December 31, 2013.
(2) The goodwill we recorded in connection with a marine business acquisition completed in November 2010 was subsequently reduced in May 2011 due to a purchase price adjustment.
(3) In December 2011, we disposed of our ownership interests in Crystal (see Note 8), including related goodwill.

Goodwill impairment testing involves determining the estimated fair value of the associated reporting unit. Our fair value estimates are based on assumptions regarding the future economic prospects of the businesses that comprise the reporting unit. Such assumptions include: (i) discrete financial forecasts for the businesses contained within the reporting unit, which, in turn, rely on management's estimates of operating margins, throughput volumes and similar factors; (ii) long-term growth rates for cash flows beyond the discrete forecast period; and (iii) appropriate discount rates. When management's assumptions are used to estimate reporting unit fair value, we believe such assumptions are consistent with the assumptions market participants would make to estimate the reporting unit's fair value. Based on our most recent goodwill impairment test at December 31, 2013, each reporting unit's fair value was substantially in excess of its carrying value (i.e., by at least 10%).

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 11. Debt Obligations

The following table presents our consolidated debt obligations (arranged by company and maturity date) at the dates indicated:

	December 31, 2013	December 31, 2012
EPO senior debt obligations:		
Commercial Paper Notes, fixed-rates (1)	$ 475.0	$ 346.6
Senior Notes C, 6.375% fixed-rate, due February 2013	--	350.0
Senior Notes T, 6.125% fixed-rate, due February 2013	--	182.5
Senior Notes M, 5.65% fixed-rate, due April 2013	--	400.0
Senior Notes U, 5.90% fixed-rate, due April 2013	--	237.6
Senior Notes O, 9.75% fixed-rate, due January 2014	500.0	500.0
364-Day Credit Agreement, variable-rate, due June 2014	--	--
Senior Notes G, 5.60% fixed-rate, due October 2014	650.0	650.0
Senior Notes I, 5.00% fixed-rate, due March 2015	250.0	250.0
Senior Notes X, 3.70% fixed-rate, due June 2015	400.0	400.0
Senior Notes FF, 1.25% fixed-rate, due August 2015	650.0	650.0
Senior Notes AA, 3.20% fixed-rate, due February 2016	750.0	750.0
Senior Notes L, 6.30% fixed-rate, due September 2017	800.0	800.0
Senior Notes V, 6.65% fixed-rate, due April 2018	349.7	349.7
$3.5 Billion Multi-Year Revolving Credit Facility, variable-rate, due June 2018	--	--
Senior Notes N, 6.50% fixed-rate, due January 2019	700.0	700.0
Senior Notes Q, 5.25% fixed-rate, due January 2020	500.0	500.0
Senior Notes Y, 5.20% fixed-rate, due September 2020	1,000.0	1,000.0
Senior Notes CC, 4.05% fixed-rate, due February 2022	650.0	650.0
Senior Notes HH, 3.35% fixed-rate, due March 2023	1,250.0	--
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0	500.0
Senior Notes H, 6.65% fixed-rate, due October 2034	350.0	350.0
Senior Notes J, 5.75% fixed-rate, due March 2035	250.0	250.0
Senior Notes W, 7.55% fixed-rate, due April 2038	399.6	399.6
Senior Notes R, 6.125% fixed-rate, due October 2039	600.0	600.0
Senior Notes Z, 6.45% fixed-rate, due September 2040	600.0	600.0
Senior Notes BB, 5.95% fixed-rate, due February 2041	750.0	750.0
Senior Notes DD, 5.70% fixed-rate, due February 2042	600.0	600.0
Senior Notes EE, 4.85% fixed-rate, due August 2042	750.0	750.0
Senior Notes GG, 4.45% fixed-rate, due February 2043	1,100.0	1,100.0
Senior Notes II, 4.85% fixed-rate, due March 2044	1,000.0	--
TEPPCO senior debt obligations:		
TEPPCO Senior Notes, 6.125% fixed-rate, due February 2013	--	17.5
TEPPCO Senior Notes, 5.90% fixed-rate, due April 2013	--	12.4
TEPPCO Senior Notes, 6.65% fixed-rate, due April 2018	0.3	0.3
TEPPCO Senior Notes, 7.55% fixed-rate, due April 2038	0.4	0.4
Total principal amount of senior debt obligations	15,825.0	14,646.6
EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066	550.0	550.0
EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067	285.8	285.8
EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068	682.7	682.7
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067	14.2	14.2
Total principal amount of senior and junior debt obligations	17,357.7	16,179.3
Other, non-principal amounts:		
Change in fair value of debt hedged in fair value hedging relationship (2)	26.4	39.3
Unamortized discounts, net of premiums	(41.5)	(38.0)
Other	8.9	21.2
Total other, non-principal amounts	(6.2)	22.5
Less current maturities of debt (3)	(1,125.0)	(1,546.6)
Total long-term debt	$ 16,226.5	$ 14,655.2

(1) Principal amounts outstanding at December 31, 2013 have fixed-rates of 0.27% and are due in January 2014.
(2) See Note 6 for information regarding our interest rate hedging activities.
(3) We expect to refinance the current maturities of our debt obligations at or prior to their maturity.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents scheduled maturities of our consolidated debt obligations for the next five years, and in total thereafter, at December 31, 2013:

		Scheduled Maturities of Debt					
	Total	2014	2015	2016	2017	2018	After 2018
Commercial Paper Notes	$ 475.0	$ 475.0	$ --	$ --	$ --	$ --	$ --
Senior Notes	15,350.0	650.0	1,300.0	750.0	800.0	350.0	11,500.0
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Total	$ 17,357.7	$ 1,125.0	$ 1,300.0	$ 750.0	$ 800.0	$ 350.0	$ 13,032.7

Long-term and current maturities of debt reflect the classification of such obligations at December 31, 2013 after taking into consideration EPO's issuance of long-term senior notes in February 2014 and the use of net proceeds received from the offering to repay debt, as described below.

In January 2014, $500.0 million in principal amount of Senior Notes O matured and were repaid using the issuance of short-term notes under EPO's commercial paper program. In February 2014, EPO issued $850 million in principal amount of 3.90% senior notes due February 2024 ("Senior Notes JJ") and $1.15 billion in principal amount of 5.10% senior notes due February 2045 ("Senior Notes KK"). Senior Notes JJ were issued at 99.811% of their principal amount and Senior Notes KK were issued at 99.845% of their principal amount. Net proceeds of $1.98 billion from the issuance of Senior Notes JJ and KK were used to repay debt, including amounts then outstanding under EPO's $3.5 Billion Multi-Year Revolving Credit Facility and commercial paper program (which EPO used to repay $500.0 million in principal amount of Senior Notes O that matured in January 2014), and for general company purposes.

Parent-Subsidiary Guarantor Relationships

Enterprise Products Partners L.P. acts as guarantor of the consolidated debt obligations of EPO with the exception of the remaining debt obligations of TEPPCO. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full and unconditional repayment of that obligation.

EPO Debt Obligations

Commercial Paper Notes. In August 2012, EPO established a commercial paper program under which it may issue (and have outstanding at any time) up to $2.0 billion in the aggregate of short-term commercial paper notes. As of December 31, 2013, a total of $475.0 million of notes were outstanding under this program. These notes matured in January 2014. We intend to maintain a minimum available borrowing capacity under EPO's $3.5 Billion Multi-Year Revolving Credit Facility equal to any amount outstanding under commercial paper notes as a back-stop to the program. All commercial paper notes issued under the program are senior unsecured obligations of EPO that are unconditionally guaranteed by Enterprise Products Partners L.P.

364-Day Credit Agreement. In June 2013, EPO entered into a 364-Day Revolving Credit Agreement with a group of lenders (the "364-Day Credit Agreement"). Under the terms of the 364-Day Credit Agreement, EPO may borrow up to $1.0 billion at a variable interest rate for a term of 364 days, subject to the terms and conditions set forth therein.

EPO's obligations under the 364-Day Credit Agreement are not secured by any collateral; however, they are guaranteed by Enterprise Products Partners L.P. Amounts borrowed under the 364-Day Credit Agreement mature on June 18, 2014, although EPO may, between 15 and 60 days prior to the maturity date, elect to have the entire principal balance then outstanding continued as a non-revolving term loan for a period of one additional year, payable on June 18, 2015.

The 364-Day Credit Agreement contains customary representations, warranties, covenants (affirmative and negative) and events of default, the occurrence of which would permit the lenders to accelerate the maturity date of amounts borrowed under the 364-Day Credit Agreement. The 364-Day Credit Agreement also restricts EPO's ability to pay cash distributions to its parent, Enterprise Products Partners L.P., if a default or an event of default (as defined in the 364-Day Credit Agreement) has occurred and is continuing at the time such distribution is scheduled to be paid.

$3.5 Billion Multi-Year Revolving Credit Facility. In June 2013, EPO amended the terms of its $3.5 Billion Multi-Year Revolving Credit Facility to, among other things, extend the maturity date of commitments under the agreement from September 2016 to June 2018 and lower the applicable margin on borrowings. Borrowings under this revolving credit facility may be used for working capital, capital expenditures, acquisitions and general company purposes.

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

The revolving credit facility contains certain financial and other customary affirmative and negative covenants. The credit agreement also restricts EPO's ability to pay cash distributions to Enterprise Products Partners L.P. if a default or an event of default (as defined in the credit agreement) has occurred and is continuing at the time such distribution is scheduled to be paid. EPO's borrowings under this revolving credit facility are unsecured general obligations that are guaranteed by Enterprise Products Partners L.P. and are non-recourse to Enterprise GP.

Senior Notes. EPO's fixed-rate senior notes are unsecured obligations of EPO that rank equal with its existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. EPO's senior notes are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict its ability (with certain exceptions) to incur debt secured by liens and engage in sale and leaseback transactions. In total, EPO issued $2.25 billion, $2.5 billion and $2.75 billion of senior notes during the years ended December 31, 2013, 2012 and 2011, respectively.

In March 2013, EPO issued $1.25 billion in principal amount of 3.35% senior notes due March 2023 ("Senior Notes HH") and $1.0 billion in principal amount of 4.85% senior notes due March 2044 ("Senior Notes II"). Senior Notes HH were issued at 99.908% of their principal amount and Senior Notes II were issued at 99.619% of their principal amount. Net proceeds from the issuance of Senior Notes HH and II were used to repay debt, including (i) amounts outstanding under EPO's $3.5 Billion Multi-Year Revolving Credit Facility and commercial paper program (which EPO used to repay $550.0 million principal amount of senior notes that matured in February 2013) and (ii) $650.0 million principal amount of senior notes that matured in April 2013, and for general company purposes.

Junior Subordinated Notes. EPO's payment obligations under its junior notes are subordinated to all of its current and future senior indebtedness (as defined in the related indenture agreement). Enterprise Products Partners L.P. guarantees repayment of amounts due under these junior notes through an unsecured and subordinated guarantee. The indenture agreement governing these notes allows EPO to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. Subject to certain exceptions, during any period in which interest payments are deferred, neither we nor EPO can declare or make any distributions on any of our respective equity securities or make any payments on indebtedness or other obligations that rank equal with or are subordinate to our junior notes. Each series of our junior notes rank equal with each other. Generally, each series of junior notes are not redeemable by EPO absent payment of a make-whole premium (while such notes bear interest at a fixed annual rate).

In connection with the issuance of each series of junior notes, EPO entered into separate Replacement Capital Covenants in favor of covered debt holders (as defined in the underlying documents) pursuant to which EPO agreed, for the benefit of such debt holders, that it would not redeem or repurchase such junior notes unless such redemption or repurchase is made using proceeds from the issuance of certain securities.

The following table summarizes the interest rate terms of our junior subordinated notes:

Series	Fixed Annual Interest Rate	Variable Annual Interest Rate Thereafter
Junior Subordinated Notes A	8.375% through August 2016 (1)	3-month LIBOR rate + 3.708% (4)
Junior Subordinated Notes B	7.034% through January 2018 (2)	Greater of: (i) 3-month LIBOR rate + 2.68% or (ii) 7.034% (5)
Junior Subordinated Notes C	7.00% through June 2017 (3)	3-month LIBOR rate + 2.778% (6)

(1) Interest is payable semi-annually in arrears in February and August of each year, which commenced in February 2007.
(2) Interest is payable semi-annually in arrears in January and July of each year, which commenced in January 2008.
(3) Interest is payable semi-annually in arrears in June and December of each year, which commenced in December 2009.
(4) Interest is payable quarterly in arrears in February, May, August and November of each year commencing in November 2016.
(5) Interest is payable quarterly in arrears in January, April, July and October of each year commencing in April 2018.
(6) Interest is payable quarterly in arrears in March, June, September and December of each year commencing in June 2017.

Remaining TEPPCO Debt Obligations

In October 2009, substantially all of the senior notes and junior subordinated notes of TEPPCO were exchanged for an equal amount of new EPO senior notes and junior subordinated notes. A small number of the original TEPPCO notes were not presented for exchange and remain outstanding. In connection with the October 2009 debt exchange, substantially all of the restrictive covenants and reporting requirements associated with the remaining TEPPCO notes were eliminated.

Letters of Credit

At December 31, 2013, EPO had $2.5 million of letters of credit outstanding related to operations at our facilities and motor fuel tax obligations.

Lender Financial Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at December 31, 2013.

Information Regarding Variable Interest Rates Paid

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt during the year ended December 31, 2013:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
EPO $3.5 Billion Multi-Year Revolving Credit Facility	1.14% to 1.51%	1.28%

Note 12. Equity and Distributions

Partners Equity

On September 7, 2011, the 24,036,950 common units of Duncan Energy Partners outstanding at the effective date of the Duncan Merger (other than those beneficially owned by EPO) were converted into Enterprise common units at a ratio of 1.01 Enterprise common units to each Duncan Energy Partners' common unit. As a result, Duncan Energy Partners' unitholders received 24,277,310 Enterprise common units (net of fractional Enterprise common units that were cashed out) as consideration in the Duncan Merger. No Enterprise common units were issued to EPO or its subsidiaries as merger consideration.

As a result of the Duncan Merger, the noncontrolling interests of Enterprise related to limited partner interests in Duncan Energy Partners that were owned by third parties other than EPO or its subsidiaries were reclassified to limited partners' equity at the effective date of the Duncan Merger. This reclassification adjustment transferred approximately $401.7 million from noncontrolling interests to limited partners' equity.

Partners' equity reflects the various classes of limited partner interests (i.e., common units, including restricted common units, and Class B units) that we have outstanding. The following table summarizes changes in the number of Enterprise's outstanding units since December 31, 2010:

	Common Units (Unrestricted)	Restricted Common Units	Total Common Units
Balance, December 31, 2010	840,119,958	3,561,614	843,681,572
Common units issued in connection with underwritten offering	10,350,000	--	10,350,000
Common units issued in connection with Duncan Merger	24,277,310	--	24,277,310
Common units issued in connection with our DRIP and EUPP	2,337,904	--	2,337,904
Common units issued in connection with the vesting of restricted common unit awards	924,108	(924,108)	--
Restricted common unit awards issued	--	1,414,630	1,414,630
Forfeiture of restricted common unit awards	--	(183,920)	(183,920)
Acquisition and cancellation of treasury units in connection with the vesting of equity-based awards	(255,276)	--	(255,276)
Other	(1,802)	--	(1,802)
Balance, December 31, 2011	877,752,202	3,868,216	881,620,418
Common units issued in connection with underwritten offering	9,200,000	--	9,200,000
Common units issued in connection with our at-the-market program	3,978,545	--	3,978,545
Common units issued in connection with our DRIP and EUPP	2,814,660	--	2,814,660
Common units issued in connection with the vesting of unit options	213,914	--	213,914
Common units issued in connection with the vesting of restricted common unit awards	1,316,603	(1,316,603)	--
Common units issued in connection with the vesting of other types of equity-based awards	52,168	--	52,168
Restricted common unit awards issued	--	1,588,738	1,588,738
Forfeiture of restricted common unit awards	--	(246,865)	(246,865)
Acquisition and cancellation of treasury units in connection with the vesting of equity-based awards	(408,241)	--	(408,241)
Balance, December 31, 2012	894,919,851	3,893,486	898,813,337
Common units issued in connection with underwritten offering	18,400,000	--	18,400,000
Common units issued in connection with our at-the-market program	7,624,689	--	7,624,689
Common units issued in connection with our DRIP and EUPP	5,154,127	--	5,154,127
Common units issued in connection with the vesting of unit options	200,882	--	200,882
Common units issued in connection with the vesting of restricted common unit awards	1,885,348	(1,885,348)	--
Conversion and reclassification of Class B units to common units	4,520,431	--	4,520,431
Restricted common unit awards issued	--	1,774,526	1,774,526
Forfeiture of restricted common unit awards	--	(172,057)	(172,057)
Acquisition and cancellation of treasury units in connection with the vesting of equity-based awards	(630,927)	--	(630,927)
Balance, December 31, 2013	932,074,401	3,610,607	935,685,008

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Sixth Amended and Restated Agreement of Limited Partnership (as amended from time to time, the "Partnership Agreement"). We are managed by our general partner, Enterprise GP.

In accordance with our Partnership Agreement, capital accounts are maintained for our limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the equity amounts presented in our consolidated financial statements prepared in accordance with GAAP. Earnings and cash distributions are allocated to holders of our common units in accordance with their respective percentage interests.

In June 2013, we filed with the SEC a new universal shelf registration statement (the "2013 Shelf") that replaced our prior universal shelf registration statement filed with the SEC in July 2010 (the "2010 Shelf"). The 2013 Shelf allows (and the prior 2010 Shelf allowed) Enterprise Products Partners L.P. and EPO (each on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. We used the 2013 Shelf and 2010 Shelf to facilitate the following securities offerings:

- § We used the 2010 Shelf to issue 10,350,000 common units to the public (including an over-allotment amount of 1,350,000 common units) at an offering price of $44.68 per unit in December 2011, which generated total net cash proceeds of $448.5 million. In addition, EPO utilized the 2010 Shelf to issue $2.75 billion of unsecured senior notes during 2011.

- § We used the 2010 Shelf to issue 9,200,000 common units to the public (including an over-allotment amount of 1,200,000 common units) at an offering price of $53.07 per unit in September 2012, which generated total net cash proceeds of $473.3 million. In addition, EPO issued $2.5 billion of unsecured senior notes during 2012 using the 2010 Shelf.

- § We used the 2010 Shelf to issue 9,200,000 common units to the public (including an over-allotment amount of 1,200,000 common units) at an offering price of $54.56 per unit in February 2013, which generated net cash proceeds of $486.6 million. In addition, EPO issued $2.25 billion of unsecured senior notes in during 2013 using the 2010 Shelf (see Note 11).

- § We used the 2013 Shelf to issue 9,200,000 common units to the public (including an over-allotment amount of 1,200,000 common units) at an offering price of $62.05 per unit in November 2013, which generated net cash proceeds of $553.0 million.

In October 2013, we filed a registration statement with the SEC covering the issuance of up to $1.25 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings. Pursuant to this “at-the-market” program, we may sell common units under an equity distribution agreement between Enterprise Products Partners L.P. and certain broker-dealers from time-to-time by means of ordinary brokers’ transactions through the NYSE at market prices, in block transactions or as otherwise agreed to with the broker-dealer parties to the agreement. The new registration statement was declared effective on October 15, 2013 and replaced our prior registration statement with respect to the at-the-market program, which was filed with the SEC in March 2012 and covered the issuance of up to $1.0 billion of our common units.

During 2013, we issued 7,624,689 common units under our at-the-market program for aggregate gross cash proceeds of $460.4 million, resulting in total net cash proceeds of $456.3 million. During 2012, we issued 3,978,545 common units under this program for aggregate gross cash proceeds of $205.4 million, resulting in total net cash proceeds of $203.8 million. After taking into account the aggregate sale price of common units sold under our at-the-market program through December 31, 2013, we have the capacity to issue additional common units under this program up to an aggregate sales price of $1.25 billion.

We also have registration statements on file with the SEC collectively authorizing the issuance of up to 70,000,000 of our common units in connection with a distribution reinvestment plan (or “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 our common units they own by reinvesting the quarterly cash distributions they receive from us into the purchase of additional new common units. After taking into account the number of common units issued under the DRIP through December 31, 2013, we may issue an additional 18,480,878 common units under this plan. Activity under our DRIP for the last three fiscal years was as follows: 5,012,414 common units issued during 2013, which generated net cash proceeds of $287.6 million; 2,679,848 common units issued during 2012, which generated net cash proceeds of $132.6 million; and 2,241,589 common units issued during 2011, which generated net cash proceeds of $90.4 million.

In January 2013, affiliates of privately held EPCO, which own our general partner and approximately 36.4% of our limited partner interests at December 31, 2013, expressed their willingness to purchase up to $100 million of our common units during 2013 through our DRIP. During the year ended December 31, 2013, these EPCO affiliates reinvested $100.0 million, resulting in the issuance of 1,749,498 common units under our DRIP (this amount being a component of the total common units issued under the DRIP during 2013).

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In addition to the DRIP, we have registration statements on file with the SEC authorizing the issuance of our common units in connection with an employee unit purchase plan (or "EUPP"). In September 2013, our unitholders approved the amendment and restatement of the EUPP. As a result, the maximum number of common units issuable under the EUPP increased from 440,879 common units to 4,000,000 common units. In addition, the term of the EUPP was extended to September 2023. After taking into account the number of common units issued under the EUPP through December 31, 2013, we may issue an additional 3,713,444 common units under this plan. Activity under our EUPP for the last three fiscal years was as follows: 141,713 common units issued during 2013, which generated net cash proceeds of $8.5 million; 134,812 common units issued during 2012, which generated net cash proceeds of $7.1 million; and 96,315 common units issued during 2011, which generated net cash proceeds of $4.0 million.

The net cash proceeds we received from the issuance of common units during the year ended December 31, 2013 were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and commercial paper program and for general company purposes.

Class B Units. In connection with the TEPPCO Merger in October 2009, a privately held affiliate of EPCO exchanged a portion of its TEPPCO units (based on a 1.24 exchange ratio) for 4,520,431 of our Class B units in lieu of receiving common units. The Class B units automatically converted into the same number of common units on the date immediately following the payment date for the sixteenth regular quarterly distribution following the closing date of the TEPPCO Merger. The Class B units were entitled to vote together with our common units as a single class on partnership matters and generally had the same rights and privileges as our common units, except that the Class B units were not entitled to receive regular quarterly cash distributions until they automatically converted into an equal number of common units on August 8, 2013.

Treasury Units. 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. A total of 1,381,600 common units were repurchased under this program; however, no repurchases have been made since 2002. As of December 31, 2013, we and our affiliates could repurchase up to 618,400 additional common units under this program.

A total of 1,885,348 restricted common unit awards granted to employees of EPCO vested and converted to common units during the year ended December 31, 2013. Of this amount, 630,927 were sold back to us by employees to cover related withholding tax requirements. The total cost of these treasury unit purchases was approximately $36.9 million. We cancelled such treasury units immediately upon acquisition. See Note 5 for additional information regarding our equity-based awards.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive income (loss) primarily reflects the effective portion of the gain or loss on derivative instruments designated and qualified as cash flow hedges. Gain or loss amounts related to cash flow hedges recorded in accumulated other comprehensive income (loss) are reclassified to earnings in the same period(s) in which the underlying hedged forecasted transactions affect earnings. If it becomes probable that a forecasted transaction will not occur, the related net gain or loss in accumulated other comprehensive income (loss) is immediately reclassified into earnings.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the components of accumulated other comprehensive income (loss) as reported on our Consolidated Balance Sheets at the dates indicated:

	Gains and Losses on Cash Flow Hedges				
	Commodity Derivative Instruments	Interest Rate Derivative Instruments	Foreign Currency Translation Adjustment	Postretirement Benefit Plans	Total
Balance, December 31, 2012	$ 10.1	$ (383.0)	$ 1.7	$ 0.8	$ (370.4)
Other comprehensive income before reclassifications	(46.9)	6.6	--	0.4	(39.9)
Amounts reclassified from accumulated other comprehensive income	22.1	29.2	--	--	51.3
Total other comprehensive income	(24.8)	35.8	--	0.4	11.4
Balance, December 31, 2013	$ (14.7)	$ (347.2)	$ 1.7	$ 1.2	$ (359.0)

	Gains and Losses on Cash Flow Hedges					
	Commodity Derivative Instruments	Interest Rate Derivative Instruments	Foreign Currency Translation Adjustment	Postretirement Benefit Plans	Other	Total
Balance, December 31, 2011	$ (21.4)	$ (329.0)	$ 1.7	$ (1.7)	$ (1.0)	$ (351.4)
Other comprehensive income before reclassifications	17.3	(70.2)	--	2.6	--	(50.3)
Amounts reclassified from accumulated other comprehensive income	14.2	16.2	--	(0.1)	1.0	31.3
Total other comprehensive income	31.5	(54.0)	--	2.5	1.0	(19.0)
Balance, December 31, 2012	$ 10.1	$ (383.0)	$ 1.7	$ 0.8	$ --	$ (370.4)

The following table presents reclassifications out of accumulated other comprehensive income (loss) into net income during the year ended December 31, 2013:

		For the Year Ended December 31,	
	Location	2013	2012
Losses (gains) on cash flow hedges:			
Interest rate derivatives	Interest expense	$ 29.2	$ 16.2
Commodity derivatives	Revenue	22.4	(10.1)
Commodity derivatives	Operating costs and expenses	(0.3)	24.3
Total		$ 51.3	$ 30.4

Noncontrolling Interests

Noncontrolling interests as presented on our Consolidated Financial Statements represent third party ownership interests in joint ventures that we consolidate for financial reporting purposes, including Tri-States NGL Pipeline L.L.C., Independence Hub LLC, Rio Grande Pipeline Company, Wilprise Pipeline Company LLC and Enterprise EF78 LLC.

In June 2013, we formed a joint venture, Enterprise EF78 LLC, with Western Gas Partners, LP ("Western Gas") involving two NGL fractionators at our complex in Mont Belvieu, Texas. We own 75% of the joint venture's membership interests and consolidate the joint venture. Western Gas acquired a 25% noncontrolling interest in the joint venture for an initial contribution of $90.2 million. The initial contribution and subsequent contributions to fund construction are reflected as cash contributions from noncontrolling interests on our Statements of Consolidated Cash Flows.

For periods prior to the Duncan Merger in September 2011, that portion of the income of Duncan Energy Partners attributable to its limited partner interests that were owned by third parties and related parties other than EPO and its subsidiaries is a component of net income attributable to noncontrolling interests.

Cash distributions paid to or cash contributions received from the limited partners of Duncan Energy Partners other than EPO and its subsidiaries (prior to the Duncan Merger) are presented as amounts paid to or received from noncontrolling interests in 2011.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents additional information regarding noncontrolling interests as presented on our Consolidated Balance Sheets at the dates indicated:

	December 31, 2013	December 31, 2012
Joint venture partners	$ 225.6	$ 108.3

The following table presents the components of net income attributable to noncontrolling interests as presented on our Statements of Consolidated Operations for the periods indicated:

	For the Year Ended December 31, 2013	2012	2011
Limited partners of Duncan Energy Partners other than EPO and its subsidiaries (prior to Duncan Merger)	$ --	$ --	$ 20.9
Joint venture partners	10.2	8.1	20.5
Total	$ 10.2	$ 8.1	$ 41.4

The following table presents cash distributions paid to and cash contributions received from noncontrolling interests as presented on our Statements of Consolidated Cash Flows and Statements of Consolidated Equity for the periods indicated:

	For the Year Ended December 31, 2013	2012	2011
Cash distributions paid to noncontrolling interests:			
Limited partners of Duncan Energy Partners other than EPO and its subsidiaries (prior to Duncan Merger)	$ --	$ --	$ 32.9
Joint venture partners	8.9	13.3	27.8
Total	$ 8.9	$ 13.3	$ 60.7
Cash contributions from noncontrolling interests:			
Limited partners of Duncan Energy Partners other than EPO and its subsidiaries (prior to Duncan Merger)	$ --	$ --	$ 2.6
Joint venture partners	115.4	6.6	5.9
Total	$ 115.4	$ 6.6	$ 8.5

Cash Distributions

The following table presents Enterprise's declared quarterly cash distribution rates per common unit with respect to 2012 and 2013 and the related record and payment dates. The quarterly cash distribution rates per common unit correspond to the fiscal quarters indicated. Actual cash distributions are paid by Enterprise within 45 days after the end of each fiscal quarter.

	Distribution Per Common Unit	Record Date	Payment Date
2012			
1st Quarter	$ 0.6275	04/30/12	05/09/12
2nd Quarter	$ 0.6350	07/31/12	08/08/12
3rd Quarter	$ 0.6500	10/31/12	11/08/12
4th Quarter	$ 0.6600	01/31/13	02/07/13
2013			
1st Quarter	$ 0.6700	04/30/13	05/07/13
2nd Quarter	$ 0.6800	07/31/13	08/07/13
3rd Quarter	$ 0.6900	10/31/13	11/07/13
4th Quarter	$ 0.7000	01/31/14	02/07/14

As previously noted, 4,520,431 Class B units automatically converted into an equal number of distribution-bearing common units on August 8, 2013.

On September 3, 2010, Enterprise GP Holdings L.P. ("Holdings"), Enterprise, Enterprise GP, Enterprise Products GP, LLC ("EPGP, the former general partner of Enterprise) and Enterprise ETE LLC ("Holdings

MergerCo," a wholly owned subsidiary of Enterprise) entered into a merger agreement (the "Holdings Merger Agreement"). On November 22, 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with and into Holdings MergerCo and related transactions were completed, with Holdings MergerCo surviving such merger. Collectively, we refer to these transactions as the "Holdings Merger."

In connection with the Holdings Merger, a privately held affiliate of EPCO agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from us with respect to a certain number of our common units it owns (the "Designated Units"). The temporary distribution waiver remains in effect for five years following the closing date of the Holdings Merger. Distributions paid to partners during calendar years 2011, 2012 and 2013 excluded 30,610,000, 26,130,000 and 23,700,000 Designated Units, respectively. For the remaining term of the waiver agreement, distributions to be paid, if any, during each of the calendar years 2014 and 2015 will exclude 22,560,000 common units and 17,690,000 common units, respectively.

The number of our distribution-bearing units will increase as the number of Designated Units decrease. For example, the number of our distribution-bearing units increased by 1,140,000 beginning with the February 2014 distribution and will increase in subsequent years as the number of Designated Units declines as scheduled in the waiver agreement.

Note 13. Business Segments

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 types of services rendered (or technologies employed) and products produced and/or sold. The following information summarizes the current assets and operations of each business segment (mileage and other statistics are unaudited):

§ Our NGL Pipelines & Services business segment includes our natural gas processing plants and related NGL marketing activities; approximately 19,400 miles of NGL pipelines; NGL and related product storage facilities; and 15 NGL fractionators. This segment also includes our NGL import and LPG export terminal operations.

§ Our Onshore Natural Gas Pipelines & Services business segment includes approximately 19,600 miles of onshore natural gas pipeline systems that provide for the gathering and transportation of natural gas in Colorado, Louisiana, New Mexico, Texas and Wyoming. We lease underground salt dome natural gas storage facilities located in Texas and Louisiana and own an underground salt dome storage cavern in Texas, all of which are important to our natural gas pipeline operations. This segment also includes our related natural gas marketing activities.

§ Our Onshore Crude Oil Pipelines & Services business segment includes approximately 4,600 miles of onshore crude oil pipelines, crude oil storage terminals located in Oklahoma and Texas, and our crude oil marketing activities. This business also includes a fleet of approximately 470 tractor-trailer tank trucks, the majority of which we lease and operate, used to transport crude oil for us and third parties.

§ 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 2,300 miles of offshore natural gas and crude oil pipelines and six offshore hub platforms.

§ Our Petrochemical & Refined Products Services business segment includes (i) propylene fractionation and related operations, including 680 miles of pipelines; (ii) a butane isomerization complex and related pipeline assets; (iii) octane enhancement and high purity isobutylene production facilities; (iv) refined products pipelines aggregating 4,200 miles and related marketing activities; and (v) marine transportation.

All activities included in our former sixth reportable business segment, Other Investments, ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our previously held investment in Energy Transfer Equity. See Note 9 for information regarding the liquidation of our investment in Energy Transfer Equity.

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-based rates. Our consolidated revenues reflect the elimination of intercompany transactions. Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our executive management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income.

In total, gross operating margin represents operating income exclusive of (1) depreciation, amortization and accretion expenses, (2) impairment charges, (3) gains and losses attributable to asset sales and insurance recoveries and (4) general and administrative costs. As discussed below, gross operating margin includes equity in income of unconsolidated affiliates and non-refundable deferred transportation revenues relating to the make-up rights of committed shippers associated with certain pipelines. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in consolidation. Gross operating margin is exclusive of other income and expense transactions, income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before any allocation of earnings to noncontrolling interests.

We include equity in income of unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Equity investments with industry partners are a significant component of our business strategy. They are a means by which we conduct our operations to align our interests with those of customers and/or suppliers. This method of operation enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed. Many of these businesses perform supporting or complementary roles to our other midstream business operations.

Our integrated midstream energy asset network (including the midstream energy assets owned by our equity method investees) provides services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. In general, hydrocarbons may enter our asset system in a number of ways, such as through an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an onshore natural gas gathering pipeline, an onshore crude oil pipeline or terminal, an NGL fractionator, an NGL storage facility or an NGL gathering or transportation pipeline. Many of our equity investees are included within our integrated midstream asset network. For example, we have ownership interests in several offshore Gulf of Mexico natural gas and crude oil pipelines. Other examples include our use of the Promix NGL fractionator to process mixed NGLs extracted by our natural gas processing plants and our use of the Texas Express Pipeline to transport mixed NGLs to our Mont Belvieu complex. Given the integral nature of our equity method investees to our operations, we believe the presentation of equity earnings from such investees as a component of gross operating margin and operating income is meaningful and appropriate.

Management includes deferred transportation revenues relating to the make-up rights of committed shippers when reviewing the financial results of certain major new pipeline projects such as the Texas Express Pipeline and Seaway Pipeline. Certain shippers on these systems did not meet their minimum volume commitment beginning in the fourth quarter of 2013, thus revenues associated with each shipper's make-up rights were deferred in accordance with GAAP. From an internal (and segment) reporting standpoint, management considers the transportation fees paid by committed shippers on major new pipeline projects, including any non-refundable revenues that may be deferred under GAAP related to make-up rights, to be important in assessing the financial performance of these pipeline assets. From a GAAP perspective, the revenue streams associated with these make-up rights are deferred until the earlier of (i) the deficiency volumes are shipped, (ii) the contractual make-up period expires or (iii) the pipeline is otherwise released from its performance obligation. Since management includes these deferred revenues in non-GAAP gross operating margin, these amounts are deducted in determining GAAP-based operating income. Our consolidated revenues do not reflect any deferred revenues until the conditions for recognizing such revenues are met in accordance with GAAP.

Segment assets consist of property, plant and equipment, investments in unconsolidated affiliates, intangible assets and goodwill. The carrying values of such amounts are assigned to each segment based on each asset's or investment's principal operations and contribution to the gross operating margin of that particular segment. Since construction-in-progress amounts (a component of property, plant and equipment) generally do not contribute to segment gross operating margin, such amounts are excluded from segment asset totals until the underlying assets are placed in service. Intangible assets and goodwill are assigned to each segment based on the classification of the assets to which they relate. Substantially all of our plants, pipelines and other fixed assets are located in the U.S.

The following table presents our measurement of non-GAAP total segment gross operating margin for the periods indicated:

	For the Year Ended December 31,		
	2013	**2012**	**2011**
Revenues	$ 47,727.0	$ 42,583.1	$ 44,313.0
Subtract operating costs and expenses	(44,238.7)	(39,367.9)	(41,318.5)
Add equity in income of unconsolidated affiliates	167.3	64.3	46.4
Add depreciation, amortization and accretion expense amounts excluded from gross operating margin	1,148.9	1,061.7	958.7
Add impairment charges excluded from gross operating margin	92.6	63.4	27.8
Add operating lease expenses paid by EPCO excluded from gross operating margin	--	--	0.3
Subtract gains attributable to asset sales and insurance recoveries excluded from gross operating margin	(83.4)	(17.6)	(156.0)
Add non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects included in gross operating margin	4.4	--	--
Total segment gross operating margin	$ 4,818.1	$ 4,387.0	$ 3,871.7

The following table presents a reconciliation of total segment gross operating margin to operating income and further to income before income taxes for the periods indicated:

	For the Year Ended December 31,		
	2013	**2012**	**2011**
Total segment gross operating margin	$ 4,818.1	$ 4,387.0	$ 3,871.7
Adjustments to reconcile total segment gross operating margin to operating income:			
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(1,148.9)	(1,061.7)	(958.7)
Subtract impairment charges not reflected in gross operating margin	(92.6)	(63.4)	(27.8)
Subtract operating lease expenses paid by EPCO not reflected in gross operating margin	--	--	(0.3)
Add gains attributable to asset sales and insurance recoveries not reflected in gross operating margin	83.4	17.6	156.0
Subtract non-refundable deferred revenues included in gross operating margin attributable to shipper make-up rights on new pipeline projects	(4.4)	--	--
Subtract general and administrative costs not reflected in gross operating margin	(188.3)	(170.3)	(181.8)
Operating income	3,467.3	3,109.2	2,859.1
Other expense, net	(802.7)	(698.4)	(743.6)
Income before income taxes	$ 2,664.6	$ 2,410.8	$ 2,115.5

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Information by business segment, together with reconciliations to our consolidated financial statement totals, is presented in the following table:

	Reportable Business Segments							
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Other Investments	Adjustments and Eliminations	Consolidated Total
Revenues from third parties:								
Year ended December 31, 2013	$ 17,119.1	$ 3,522.7	$ 20,609.1	$ 151.7	$ 6,258.5	$ --	$ --	$ 47,661.1
Year ended December 31, 2012	15,158.9	3,297.7	17,661.6	182.7	6,208.9	--	--	42,509.8
Year ended December 31, 2011	16,938.1	3,510.0	16,061.0	246.4	6,782.4	--	--	43,537.9
Revenues from related parties:								
Year ended December 31, 2013	1.1	15.8	41.3	7.7	--	--	--	65.9
Year ended December 31, 2012	9.5	54.9	0.1	8.8	--	--	--	73.3
Year ended December 31, 2011	545.2	220.2	0.1	9.6	--	--	--	775.1
Intersegment and intrasegment revenues:								
Year ended December 31, 2013	11,096.6	959.7	10,222.3	9.6	1,764.0	--	(24,052.2)	--
Year ended December 31, 2012	12,500.6	871.6	6,906.9	10.4	1,758.9	--	(22,048.4)	--
Year ended December 31, 2011	13,657.7	1,131.8	4,904.3	6.6	1,799.1	--	(21,499.5)	--
Total revenues:								
Year ended December 31, 2013	28,216.8	4,498.2	30,872.7	169.0	8,022.5	--	(24,052.2)	47,727.0
Year ended December 31, 2012	27,669.0	4,224.2	24,568.6	201.9	7,967.8	--	(22,048.4)	42,583.1
Year ended December 31, 2011	31,141.0	4,862.0	20,965.4	262.6	8,581.5	--	(21,499.5)	44,313.0
Equity in income (loss) of unconsolidated affiliates:								
Year ended December 31, 2013	15.7	3.8	140.3	29.8	(22.3)	--	--	167.3
Year ended December 31, 2012	15.9	4.4	32.6	26.9	(17.9)	2.4	--	64.3
Year ended December 31, 2011	21.8	5.5	(4.1)	27.1	(18.7)	14.8	--	46.4
Gross operating margin:								
Year ended December 31, 2013	2,514.4	789.0	742.7	146.1	625.9	--	--	4,818.1
Year ended December 31, 2012	2,468.5	775.5	387.7	173.0	579.9	2.4	--	4,387.0
Year ended December 31, 2011	2,184.2	675.3	234.0	228.2	535.2	14.8	--	3,871.7
Property, plant and equipment, net: (see Note 8)								
At December 31, 2013	9,957.8	8,917.3	1,479.9	1,223.7	2,712.4	--	2,655.5	26,946.6
At December 31, 2012	8,494.8	8,950.1	1,385.9	1,343.0	2,559.5	--	2,113.1	24,846.4
At December 31, 2011	7,137.8	8,495.4	456.9	1,416.4	2,539.5	--	2,145.6	22,191.6
Investments in unconsolidated affiliates: (see Note 9)								
At December 31, 2013	645.5	24.2	1,165.2	531.8	70.4	--	--	2,437.1
At December 31, 2012	324.6	24.9	493.8	479.0	72.3	--	--	1,394.6
At December 31, 2011	146.1	30.1	170.7	424.9	64.7	1,023.1	--	1,859.6
Intangible assets, net: (see Note 10)								
At December 31, 2013	285.2	1,017.8	4.5	54.7	100.0	--	--	1,462.2
At December 31, 2012	320.6	1,067.9	5.9	66.2	106.2	--	--	1,566.8
At December 31, 2011	341.3	1,127.8	5.8	77.5	103.8	--	--	1,656.2

Goodwill: (see Note 10)								
At December 31, 2013	341.2	296.3	305.1	82.1	1,055.3	--	--	2,080.0
At December 31, 2012	341.2	296.3	311.2	82.1	1,056.0	--	--	2,086.8
At December 31, 2011	341.2	296.3	311.2	82.1	1,061.5	--	--	2,092.3
Segment assets:								
At December 31, 2013	11,229.7	10,255.6	2,954.7	1,892.3	3,938.1	--	2,655.5	32,925.9
At December 31, 2012	9,481.2	10,339.2	2,196.8	1,970.3	3,794.0	--	2,113.1	29,894.6
At December 31, 2011	7,966.4	9,949.6	944.6	2,000.9	3,769.5	1,023.1	2,145.6	27,799.7

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents additional information regarding our consolidated revenues and costs and expenses for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
NGL Pipelines & Services:			
Sales of NGLs and related products	$ 15,916.0	$ 14,218.5	$ 16,724.6
Midstream services	1,204.2	949.9	758.7
Total	17,120.2	15,168.4	17,483.3
Onshore Natural Gas Pipelines & Services:			
Sales of natural gas	2,571.6	2,395.4	2,866.5
Midstream services	966.9	957.2	863.7
Total	3,538.5	3,352.6	3,730.2
Onshore Crude Oil Pipelines & Services:			
Sales of crude oil	20,371.3	17,548.7	15,962.6
Midstream services	279.1	113.0	98.5
Total	20,650.4	17,661.7	16,061.1
Offshore Pipelines & Services:			
Sales of natural gas	0.5	0.4	1.1
Sales of crude oil	5.7	3.3	9.4
Midstream services	153.2	187.8	245.5
Total	159.4	191.5	256.0
Petrochemical & Refined Products Services:			
Sales of petrochemicals and refined products	5,568.8	5,470.9	6,000.6
Midstream services	689.7	738.0	781.8
Total	6,258.5	6,208.9	6,782.4
Total consolidated revenues	$ 47,727.0	$ 42,583.1	$ 44,313.0
Consolidated costs and expenses			
Operating costs and expenses:			
Cost of sales	$ 40,770.2	$ 36,015.5	$ 38,292.6
Other operating costs and expenses (1)	2,310.4	2,244.9	2,195.4
Depreciation, amortization and accretion	1,148.9	1,061.7	958.7
Gains attributable to asset sales and insurance recoveries	(83.4)	(17.6)	(156.0)
Non-cash asset impairment charges	92.6	63.4	27.8
General and administrative costs	188.3	170.3	181.8
Total consolidated costs and expenses	$ 44,427.0	$ 39,538.2	$ 41,500.3

(1) Represents cost of operating our plants, pipelines and other fixed assets, excluding depreciation, amortization and accretion charges.

Year-to-year fluctuations in our product sales revenues and related cost of sales amounts are explained in part by changes in energy commodity prices. In general, lower energy commodity prices result in a decrease in our revenues attributable to product sales; however, these lower commodity prices also decrease the associated cost of sales as purchase costs decline. The same correlation would be true in the case of higher energy commodity sales prices and purchase costs.

Our largest non-affiliated customer for 2013 was BP p.l.c. and its affiliates (collectively, "BP"), which accounted for $4.3 billion, or 9.0%, of our consolidated revenues for the year. The following table presents our consolidated revenues from BP by business segment for the year ended December 31, 2013:

NGL Pipelines & Services	$ 1,137.6
Onshore Natural Gas Pipelines & Services	164.3
Onshore Crude Oil Pipelines & Services	2,833.1
Petrochemical & Refined Products Services	176.7
Total consolidated revenues from BP	$ 4,311.7

BP was also our largest non-affiliated customer for 2012, accounting for 9.5% of our consolidated revenues for the year ended December 31, 2012. Shell Oil Company and its affiliates was our largest non-affiliated customer in 2011, accounting for 10.6% of our consolidated revenues for the year ended December 31, 2011.

Note 14. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
Revenues – related parties:			
Energy Transfer Equity and subsidiaries	$ --	$ --	$ 573.2
Other unconsolidated affiliates	65.9	73.3	201.9
Total revenue – related parties	$ 65.9	$ 73.3	$ 775.1
Costs and expenses – related parties:			
EPCO and affiliates	$ 892.2	$ 816.9	$ 722.7
Energy Transfer Equity and subsidiaries	--	--	1,101.5
Other unconsolidated affiliates	160.0	40.2	49.8
Total costs and expenses – related parties	$ 1,052.2	$ 857.1	$ 1,874.0

Energy Transfer Equity was a related party to us during the periods in which we accounted for our investment in its limited partner units using the equity method of accounting. We ceased reporting Energy Transfer Equity as a related party in January 2012. See Note 9 for information regarding the liquidation of our investment in Energy Transfer Equity.

For information regarding the Duncan Merger, which was a related party transaction, see Note 1.

The following table summarizes our related party accounts receivable and accounts payable balances at the dates indicated:

	December 31,	
	2013	2012
Accounts receivable - related parties:		
Unconsolidated affiliates	$ 6.8	$ 2.5
Accounts payable - related parties:		
EPCO and affiliates	$ 116.3	$ 102.4
Unconsolidated affiliates	34.2	24.7
Total	$ 150.5	$ 127.1

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.

Relationship with EPCO and Affiliates

We have an extensive and ongoing relationship with EPCO and its privately held affiliates (including Enterprise GP, our general partner), which are not a part of our consolidated group of companies. At December 31, 2013, EPCO and its privately held affiliates (including Dan Duncan LLC and certain Duncan family trusts, the beneficiaries of which include the estate of Dan L. Duncan) beneficially owned the following limited partner interests in us:

Number of Units	Percentage of Total Units Outstanding
340,880,379	36.4%

We and Enterprise GP are both separate legal entities apart from each other and apart from EPCO and its other affiliates, with assets and liabilities that are also separate from those of EPCO and its other affiliates. EPCO and its privately held affiliates depend on the cash distributions they receive from us and other investments to fund their other activities and to meet their debt obligations. During the years ended December 31, 2013, 2012 and 2011, we paid EPCO and its privately held affiliates cash distributions totaling $811.4 million, $750.2 million and $701.5 million, respectively.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

From time-to-time, EPCO and its privately held affiliates elect to reinvest a portion of the cash distributions they receive from us into the purchase of additional common units under our DRIP. See Note 12 for information regarding these reinvestments made during 2013.

Privately held affiliates of EPCO (together with their respective subsidiaries) have pledged 20,000,000 of our common units that they own as security under such affiliates' credit facilities. These credit facilities contain customary and other events of default, including defaults by us and other affiliates of EPCO. An event of default, followed by a foreclosure on the pledged collateral, could ultimately result in a change in ownership of these units. A development of this nature could affect the market price of our common units.

We lease office space from affiliates of EPCO. The rental rates in these lease agreements approximate market rates.

EPCO ASA. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA or by other service providers. We and our general partner are parties to the ASA. The significant terms of the ASA are as follows:

§ EPCO will provide selling, general and administrative services and management and operating services as may be necessary to manage and operate our businesses, properties and assets (all in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel.

§ We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including expenses reasonably allocated to us by EPCO). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time with respect to the services provided to us by EPCO.

§ EPCO will allow us to participate as a named insured in its overall insurance program, with the associated premiums and other costs being allocated to us. See Note 18 for additional information regarding our insurance programs.

Under the ASA, EPCO subleased to us (for $1 per year) certain equipment it held pursuant to operating leases. EPCO was liable for the cash payments associated with these lease agreements. In June 2011, we paid $5.4 million to purchase the assets from the lessor and the lease agreements were terminated. While these lease agreements were in effect, we recorded the full value of the lease payments made by EPCO on our behalf as a non-cash related party operating expense, with the offset to equity accounted for as a general contribution to our partnership. The value of these lease payments was $0.3 million for the year ended December 31, 2011.

Our operating costs and expenses include amounts paid to EPCO for the costs it incurs to operate our facilities, including the compensation of its employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. Likewise, our general and administrative costs include amounts paid to EPCO for administrative services, including the compensation of its employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation of legal or accounting salaries based on estimates of time spent on each entity's business and affairs).

The following table presents our costs and expenses attributable to the ASA and other related party transactions with EPCO for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
Operating costs and expenses	$ 770.7	$ 719.4	$ 611.6
General and administrative expenses	121.5	97.5	111.1
Total costs and expenses	$ 892.2	$ 816.9	$ 722.7

Since the vast majority of such expenses are charged to us on an actual basis (i.e., no mark-up or subsidy is charged or received by EPCO), we believe that such expenses are representative of what the amounts would have been on a standalone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPCO is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. The following information summarizes significant related party transactions with our current unconsolidated affiliates:

§ For the years ended December 31, 2013, 2012 and 2011, we paid Seaway $132.4 million, $18.1 million and $1.4 million, respectively, for pipeline transportation and storage services in connection with our crude oil marketing activities. Revenues from Seaway were $41.3 million for the year ended December 31, 2013.

§ We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. Revenues from Promix were $9.8 million, $7.8 million and $18.3 million for the years ended December 31, 2013, 2012 and 2011, respectively. Expenses with Promix were $28.1 million, $27.4 million and $44.9 million for the years ended December 31, 2013, 2012 and 2011, respectively.

§ For the year ended December 31, 2013, 2012 and 2011, we paid White River Hub $6.6 million, $6.6 million and $6.7 million, respectively, for pipeline transportation services.

§ We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $21.8 million, $19.4 million and $13.0 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Prior to acquiring the remaining ownership interests in Evangeline in June 2012, we sold natural gas to Evangeline, which, in turn, used the natural gas to satisfy its supply commitments to a customer. Revenues from Evangeline were $42.9 million and $166.1 million for the years ended December 31, 2012 and 2011, respectively.

Note 15. Provision for Income Taxes

Provision for income taxes primarily reflects our state tax obligations under the Revised Texas Franchise Tax (the “Texas Margin Tax”). Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities of our tax paying entities for financial reporting and tax purposes.

We recognized income tax expense of $57.5 million for the year ended December 31, 2013, of which $19.6 million was attributable to certain legislative changes to the Texas Margin Tax enacted during the second quarter of 2013.

During the year ended December 31, 2012, we recognized an overall income tax benefit of $17.2 million, which was primarily due to a $45.3 million income tax benefit related to the conversion of certain of our subsidiaries to limited liability companies, partially offset by accruals for the Texas Margin Tax. The $45.3 million income tax benefit is attributable to the difference between deferred income taxes accrued by the applicable subsidiaries through the date of conversion and any current income tax due in connection with the conversions.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Our federal and state income tax provision (benefit) is summarized below:

	For the Year Ended December 31,		
	2013	2012	2011
Current:			
Federal	$ (0.5)	$ 18.9	$ (4.0)
State	19.3	28.9	18.9
Foreign	0.8	1.2	0.2
Total current	19.6	49.0	15.1
Deferred:			
Federal	(0.5)	(64.7)	11.5
State	38.9	(1.4)	0.8
Foreign	(0.5)	(0.1)	(0.2)
Total deferred	37.9	(66.2)	12.1
Total provision for (benefit from) income taxes	$ 57.5	$ (17.2)	$ 27.2

A reconciliation of the provision for (benefit from) income taxes with amounts determined by applying the statutory U.S. federal income tax rate to income before income taxes is as follows:

	For the Year Ended December 31,		
	2013	2012	2011
Pre-Tax Net Book Income ("NBI")	$ 2,664.6	$ 2,410.8	$ 2,115.5
Texas Margin Tax (1)	$ 58.3	$ 23.5	$ 19.1
State income taxes (net of federal benefit)	(0.1)	5.3	0.5
Federal income taxes computed by applying the federal statutory rate to NBI of corporate entities	(1.4)	(1.6)	5.0
Valuation allowance	--	(2.0)	(0.2)
Expiration of tax net operating loss	0.1	2.4	0.2
Tax gain on conversion of corporate subsidiaries into limited liability companies	--	(45.3)	--
Other permanent differences	0.6	0.5	2.6
Provision for (benefit from) income taxes	$ 57.5	$ (17.2)	$ 27.2
Effective income tax rate	2.2%	(0.7)%	1.3%

(1) Although the Texas Margin Tax is not considered a state income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers our Texas-sourced revenues and expenses.

The following table presents the significant components of deferred tax assets and deferred tax liabilities at the dates indicated:

	At December 31,	
	2013	2012
Deferred tax assets:		
Net operating loss carryovers (1)	$ 0.1	$ 0.2
Employee benefit plans	0.2	0.1
Accruals	2.0	1.5
Total deferred tax assets	2.3	1.8
Valuation allowance (2)	--	--
Net deferred tax assets	2.3	1.8
Less: Deferred tax liabilities:		
Property, plant and equipment	59.8	23.7
Equity investment in partnerships	2.9	0.6
Total deferred tax liabilities	62.7	24.3
Total net deferred tax liabilities	$ 60.4	$ 22.5
Current portion of total net deferred tax assets	$ 0.4	$ --
Long-term portion of total net deferred tax liabilities	$ 60.8	$ 22.5

(1) These losses expire in various years between 2014 and 2028 and are subject to limitations on their utilization.
(2) We record a valuation allowance to reduce our deferred tax assets to the amount of future benefit that is more likely than not to be realized.

Current accounting guidance provides that a tax benefit from an uncertain tax position may be recognized when it is more likely than not that the position will be sustained upon examination, including resolutions of any related appeals or litigation processes, based on the technical merits. We did not rely on any uncertain tax positions in recording our income tax-related amounts during the years ended December 31, 2013, 2012 or 2011.

Note 16. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss attributable to our limited partners by the weighted-average number of our distribution-bearing units outstanding during a period, which excludes the Designated Units (see Note 12) to the extent such units do not participate in the distributions to be paid with respect to such period.

Diluted earnings per unit is computed by dividing net income or loss attributable to our limited partners by the sum of (i) the weighted-average number of our distribution-bearing units outstanding during a period (as used in determining basic earnings per unit), (ii) the weighted-average number of our Class B units (see Note 12) outstanding during a period, (iii) the weighted-average number of Designated Units outstanding during a period and (iv) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the “incremental option units”).

In a period of net losses, the Class B units, Designated Units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. The dilutive incremental option units are calculated using the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the end of each period are used to repurchase common units at an average market price during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

The following table presents our calculation of basic and diluted earnings per unit for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
BASIC EARNINGS PER UNIT			
Numerator:			
Net income attributable to limited partners	$ 2,596.9	$ 2,419.9	$ 2,046.9
Denominator:			
Weighted-average number of distribution-bearing common units outstanding	894.0	861.8	824.6
Basic earnings per unit:			
Net income attributable to limited partners	$ 2.90	$ 2.81	$ 2.48
DILUTED EARNINGS PER UNIT			
Numerator:			
Net income attributable to limited partners	$ 2,596.9	$ 2,419.9	$ 2,046.9
Denominator:			
Weighted-average number of units outstanding:			
Distribution-bearing common units	894.0	861.8	824.6
Class B units	2.7	4.5	4.5
Designated Units	23.4	25.5	29.5
Incremental option units	1.2	1.4	1.3
Total	921.3	893.2	859.9
Diluted earnings per unit:			
Net income attributable to limited partners	$ 2.82	$ 2.71	$ 2.38

Note 17. Commitments and Contingencies

Litigation

As part of our normal business activities, we may be named as defendants in legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to fully indemnify us against losses arising from future legal proceedings. We will vigorously defend the partnership in litigation matters.

Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the possible need for accounting recognition and disclosure of these contingencies. We accrue an undiscounted liability for those contingencies where the loss is probable and the amount can be reasonably estimated. If a range of probable loss amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum amount in the range is accrued.

We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when the likelihood of loss is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material to our consolidated financial statements, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss. Based on a consideration of all relevant known facts and circumstances, we do not believe that the ultimate outcome of any currently pending litigation directed against us will have a material impact on our consolidated financial statements either individually at the claim level or in the aggregate.

At December 31, 2013 and 2012, our accruals for litigation contingencies were $3.7 million and $4.4 million, respectively, and were recorded in our Consolidated Balance Sheets as a component of “Other current liabilities.” Our evaluation of litigation contingencies is based on the facts and circumstances of each case and predicting the outcome of these matters involves uncertainties. In the event the assumptions we use to evaluate these matters change in future periods or new information becomes available, we may be required to record additional accruals. In an effort to mitigate expenses associated with litigation, we may settle legal proceedings out of court.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Redelivery Commitments

We store natural gas, crude oil, NGLs and certain petrochemical products owned by third parties under various agreements. Under the terms of these agreements, we are generally required to redeliver volumes to the owner on demand. At December 31, 2013, we had approximately 9.7 trillion British thermal units ("TBtus") of natural gas, 9.2 MMBbls of crude oil, and 25.1 MMBbls of NGL and petrochemical products in our custody that were owned by third parties. We maintain insurance coverage related to such volumes that we believe is consistent with our exposure. See Note 18 for information regarding insurance matters.

Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2013. A description of each type of contractual obligation follows:

	Payment or Settlement due by Period						
Contractual Obligations	**Total**	**2014**	**2015**	**2016**	**2017**	**2018**	**Thereafter**
Scheduled maturities of debt obligations	$ 17,357.7	$ 1,125.0	$ 1,300.0	$ 750.0	$ 800.0	$ 350.0	$ 13,032.7
Estimated cash interest payments	$ 18,092.0	$ 860.9	$ 796.6	$ 772.6	$ 758.4	$ 705.1	$ 14,198.4
Operating lease obligations	$ 332.8	$ 42.4	$ 41.2	$ 38.2	$ 35.4	$ 30.7	$ 144.9
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 4,372.0	$ 1,088.9	$ 915.8	$ 844.1	$ 472.0	$ 472.0	$ 579.2
NGLs	$ 2,147.1	$ 1,917.7	$ 214.3	$ 15.1	$ --	$ --	$ --
Crude oil	$ 1,159.5	$ 1,159.5	$ --	$ --	$ --	$ --	$ --
Petrochemicals & refined products	$ 3,943.6	$ 2,058.0	$ 1,123.7	$ 693.5	$ 68.4	$ --	$ --
Other	$ 117.0	$ 80.0	$ 8.0	$ 7.1	$ 6.5	$ 3.8	$ 11.6
Underlying major volume commitments:							
Natural gas (in TBtus)	1,143	282	237	219	128	128	149
NGLs (in MMBbls)	42	38	4	--	--	--	--
Crude oil (in MMBbls)	12	12	--	--	--	--	--
Petrochemicals & refined products (in MMBbls)	42	22	12	7	1	--	--
Service payment commitments	$ 1,030.9	$ 201.4	$ 199.6	$ 180.8	$ 154.7	$ 86.5	$ 207.9
Capital expenditure commitments	$ 1,137.5	$ 1,137.5	$ --	$ --	$ --	$ --	$ --

Scheduled Maturities of Long-Term Debt. We have long-term and short-term payment obligations under debt agreements. Amounts shown in the preceding table represent our scheduled future maturities of debt principal for the periods presented. See Note 11 for additional information regarding our consolidated debt obligations.

Estimated Cash Interest Payments. Our estimated cash payments for interest are based on the principal amount of our consolidated debt obligations outstanding at December 31, 2013 and the contractually scheduled maturities of such balances. With respect to our variable-rate debt obligation, we applied the weighted-average interest rate paid during 2013 to determine the estimated cash payments. See Note 11 for the weighted-average variable interest rate charged in 2013 under our $3.5 Billion Multi-Year Revolving Credit Facility. In addition, our estimate of cash payments for interest gives effect to interest rate swap agreements that were in place at December 31, 2013. See Note 6 for information regarding these derivative instruments. Our estimated cash payments for interest are significantly influenced by the long-term maturities of our $1.53 billion in junior subordinated notes. Our estimated cash payments for interest assume that these subordinated notes are not repaid prior to their respective maturity dates. We applied the current fixed interest rate through the respective maturity date for each junior subordinated note to determine the estimated cash payments for interest.

Operating Lease Obligations. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the preceding table represent minimum cash lease payment obligations under our operating leases with terms in excess of one year.

Our significant lease agreements consist of (i) the lease of underground storage caverns for natural gas and NGLs, (ii) leased office space with affiliates of EPCO and (iii) land held pursuant to right-of-way agreements.

Currently, our significant lease agreements have terms that range from 5 to 20 years. The agreements for leased office space with affiliates of EPCO and underground NGL storage caverns we lease from a third party include renewal options that could extend these contracts for up to an additional 20 years. The remainder of our significant lease agreements do not provide for additional renewal terms.

Lease expense is charged to operating costs and expenses on a straight-line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. We are generally required to perform routine maintenance on the underlying leased assets. In addition, certain leases give us the option to make leasehold improvements. Maintenance and repairs of leased assets resulting from our operations are charged to expense as incurred. We did not make any significant leasehold improvements during the years ended December 31, 2013, 2012 or 2011.

Consolidated costs and expenses include lease and rental expense amounts of $87.6 million, $95.1 million and $86.2 million during the years ended December 31, 2013, 2012 and 2011, respectively.

Purchase Obligations. We define purchase obligations as agreements to purchase goods or services that are enforceable and legally binding (i.e., unconditional) on us that specify all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We classify our unconditional purchase obligations into the following categories:

§ We have long and short-term product purchase obligations for natural gas, NGLs, crude oil, petrochemicals and refined products with third party suppliers. The prices that we are obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The preceding table shows our volume commitments and estimated payment obligations under these contracts for the periods presented. Our estimated future payment obligations are based on the contractual price in each agreement at December 31, 2013 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery. At December 31, 2013, we did not have any significant product purchase commitments with fixed or minimum pricing provisions with remaining terms in excess of one year.

§ We have long and short-term commitments to pay service providers. Our contractual service payment commitments primarily represent our obligations under firm pipeline transportation contracts. Payment obligations vary by contract, but generally represent a price per unit of volume multiplied by a firm transportation volume commitment.

§ We have short-term payment obligations relating to our capital spending program, including our share of the capital spending of our unconsolidated affiliates. These commitments represent unconditional payment obligations for services to be rendered or products to be delivered in connection with capital projects.

Other Long-Term Liabilities

As reflected on our Consolidated Balance Sheet at December 31, 2013, other long-term liabilities primarily represent the noncurrent portion of asset retirement obligations and deferred revenues.

Commitments Under Equity Compensation Plans of EPCO

In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense associated with certain employees who perform management, administrative and operating functions for us (see Note 14). See Note 5 for additional information regarding our accounting for equity-based awards.

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally make claims against such parties or have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of December 31, 2013, our contingent claims against such parties were $39.2 million and claims against us were $76.0 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated at this time. With respect to claims against us, we believe that the likelihood of a material loss resulting from such claims is remote. Accordingly, no accruals for loss contingencies related to these matters have been recorded.

Centennial Guarantees

At December 31, 2013, Centennial's debt obligations consisted of $84.4 million borrowed under a master shelf loan agreement. Borrowings under the master shelf agreement mature in May 2024 and are collateralized by substantially all of Centennial's assets and severally guaranteed 50% by us and 50% by our joint venture partner in Centennial. If Centennial were to default on its debt obligations, we and our joint venture partner would each be required to make an approximate $42.2 million payment to Centennial's lenders in connection with the guarantee agreements (based on Centennial's debt principal outstanding at December 31, 2013). We recognized a liability of $6.0 million for our share of the Centennial debt guaranty at December 31, 2013.

In lieu of Centennial procuring insurance to satisfy third party claims arising from a catastrophic event, we and Centennial's other joint venture partner have entered a limited cash call agreement. We are obligated to contribute up to a maximum of $50.0 million in the event of a catastrophic event. At December 31, 2013, we have a recorded liability of $2.6 million representing the estimated fair value of our cash call guaranty. Our cash contributions to Centennial under the agreement may be covered by our other insurance policies depending on the nature of the catastrophic event.

Note 18. Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

Our operations are within the midstream energy industry, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs, crude oil, refined products and certain petrochemicals. We also market natural gas, NGLs, crude oil and other hydrocarbon products. A reduction in demand for natural gas, NGLs, crude oil, refined products, petrochemicals and other hydrocarbon products by the petrochemical, refining or heating industries, whether because of general economic conditions; reduced demand by customers; increased competition from other products due to pricing differences; adverse weather conditions; government regulations affecting energy commodity prices, production levels of hydrocarbons or the content of motor gasoline; or for other reasons, could adversely affect our financial position, results of operations and cash flows.

Credit Risk Due to Industry Concentrations

A substantial portion of our revenues are derived from companies in the domestic natural gas, NGL and petrochemical industries. This concentration could affect our overall exposure to credit risk since these customers may be affected by similar economic or other conditions. We generally do not require collateral for our accounts receivable; however, we do attempt to negotiate offset, prepayment, or automatic debit agreements with customers that are deemed to be credit risks in order to minimize our potential exposure to any defaults. Our largest non-affiliated customer for 2013 was BP, which accounted for 9.0% of our consolidated revenues for this period.

Counterparty Risk with Respect to Derivative Instruments

In those situations where we are exposed to credit risk in our derivative instrument transactions, we analyze the counterparty's financial condition prior to entering into an agreement, establish credit and/or margin limits and monitor the appropriateness of these limits on an ongoing basis. Generally, we do not require collateral for such transactions nor do we currently anticipate nonperformance by our counterparties.

Insurance Matters

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other insurance coverage, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance may not fully cover every type of damage, interruption or other loss that might occur. If we were to incur a significant loss for which we were not fully insured, it could have a material impact on our financial position, results of operations and cash flows.

In addition, there may be timing differences between amounts we accrue related to property damage expense, amounts we are required to pay in connection with a loss, and amounts we subsequently receive from insurance carriers as reimbursements. Any event that materially interrupts the revenues generated by our consolidated operations, or other losses that require us to make material expenditures not reimbursed by insurance, could reduce our ability to pay distributions to our unitholders and, accordingly, adversely affect the market price of our common units.

Involuntary conversions result from the loss of an asset due to some unforeseen event (e.g., destruction due to a fire). Some of these events are covered by insurance, thus resulting in a property damage insurance recovery. Amounts we receive from insurance carriers are net of any deductibles related to the covered event. We record a receivable from insurance to the extent we recognize a loss from an involuntary conversion event and the likelihood of our recovering such loss is deemed probable. To the extent that any of our insurance claim receivables are later judged not probable of recovery (e.g., due to new information), such amounts are expensed. We recognize gains on involuntary conversions when the amount received from insurance exceeds the net book value of the retired asset(s).

In addition, we do not recognize gains related to insurance recoveries until all contingencies related to such proceeds have been resolved, that is, a non-refundable cash payment is received from the insurance carrier or we have a binding settlement agreement with the carrier that clearly states that a non-refundable payment will be made. To the extent that an asset is rebuilt, the associated expenditures are capitalized, as appropriate, on our Consolidated Balance Sheets and presented as capital expenditures on our Statements of Consolidated Cash Flows.

Currently, EPCO's deductibles for property damage claims range from $5.0 million to $60.0 million depending on the nature of the loss (windstorm or non-windstorm) and the assets involved (onshore or offshore assets). We continue to maintain business interruption coverage for our onshore and offshore assets, except for those situations involving windstorm-related downtime for our offshore assets.

We received $15.0 million, $30.0 million and $20.0 million of nonrefundable insurance proceeds during the years ended December 31, 2013, 2012 and 2011, respectively, attributable to property damage claims we filed in connection with a February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. Operating income for the years ended December 31, 2013, 2012 and 2011 includes $15.0 million, $30.0 million and $4.7 million of gains, respectively, related to these insurance recoveries. The remaining West Storage claims of approximately $95.0 million are anticipated to be collected during the first quarter of 2014. To the extent that additional non-refundable cash insurance proceeds related to this incident are received, we expect to record gains equal to such proceeds.

Due to the high cost of windstorm insurance coverage for our offshore Gulf of Mexico assets, we elected to self-insure these assets during the annual policy period extending from June 2012 to June 2013. We continue to self-insure these assets for the current annual policy period, which extends from June 2013 to June 2014. Although EPCO's current insurance program does not provide any windstorm coverage for our offshore assets, producers affiliated with our Independence Hub and Marco Polo platforms continue to provide certain levels of physical damage windstorm coverage for each of these offshore assets.

With respect to business interruption insurance claims, we recognize income only when we receive non-refundable cash proceeds from insurers. We recognized $4.3 million of such income during the year ended December 31, 2011. We did not receive any business interruption proceeds during the years ended December 31, 2013 and 2012.

Note 19. Supplemental Cash Flow Information

The following table provides information regarding the net effect of changes in our operating accounts and cash payments for interest and income taxes for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
Decrease (increase) in:			
Accounts receivable – trade	$ (1,136.2)	$ 161.5	$ (709.0)
Accounts receivable – related parties	(3.6)	35.3	(7.0)
Inventories	38.6	(227.8)	135.8
Prepaid and other current assets	(6.3)	(12.6)	(27.7)
Other assets	2.4	(39.6)	3.9
Increase (decrease) in:			
Accounts payable – trade	(10.1)	34.1	44.2
Accounts payable – related parties	23.6	(84.3)	78.4
Accrued product payables	1,043.8	(422.5)	726.2
Accrued interest	3.5	12.7	35.2
Other current liabilities	(35.1)	(14.4)	(23.2)
Other liabilities	(18.2)	(24.9)	10.1
Net effect of changes in operating accounts	$ (97.6)	$ (582.5)	$ 266.9
Cash payments for interest, net of $133.0, $116.8 and $106.7 capitalized in 2013, 2012 and 2011, respectively	$ 781.5	$ 757.3	$ 711.4
Cash payments for federal and state income taxes	$ 35.0	$ 44.8	$ 13.4

We incurred liabilities for construction in progress that had not been paid at December 31, 2013, 2012 and 2011 of $205.3 million, $221.7 million and $286.9 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Statements of Consolidated Cash Flows.

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 activities and production well tie-ins. These cash receipts are presented as "Contributions in aid of construction costs" within the investing activities section of our Statements of Consolidated Cash Flows.

The following table presents our cash proceeds from asset sales and insurance recoveries for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
Sale of Energy Transfer Equity common units (see Note 9)	$ --	$ 1,095.3	$ 375.2
Sale of ownership interests in Crystal (see Note 8)	--	--	547.8
Sale of marine transportation assets	--	--	53.2
Sale of Stratton Ridge-to-Mont Belvieu segment of Seminole Pipeline (see Note 8)	86.9	--	--
Sales of pipeline line fill	65.0	--	--
Sale of lubrication oil and specialty chemical distribution assets	35.3	--	--
Sale of chemical trucking assets	29.5	--	--
Insurance recoveries attributable to West Storage claims (see Note 18)	15.0	30.0	20.0
Other cash proceeds	48.9	73.5	57.6
Total	$ 280.6	$ 1,198.8	$ 1,053.8

The following table presents gains (losses) attributable to asset sales and insurance recoveries for the periods indicated:

	For the Year Ended December 31,		
	2013	2012	2011
Sale of Energy Transfer Equity common units (see Note 9)	$ --	$ 68.8	$ 27.2
Sale of ownership interests in Crystal (see Note 8)	--	--	129.1
Sale of Stratton Ridge-to-Mont Belvieu segment of Seminole Pipeline (see Note 8)	52.5	--	--
Net gains (losses) attributable to other asset sales	15.8	(12.4)	(5.3)
Gains attributable to insurance recoveries (see Note 18)	15.0	30.0	4.7
Total	$ 83.3	$ 86.4	$ 155.7

See Note 12 for information regarding cash contributions and distributions attributable to noncontrolling interests as seen on the Statements of Consolidated Cash Flows.

Note 20. Quarterly Financial Information (Unaudited)

The following table presents selected quarterly financial data for the periods indicated:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2013:				
Revenues	$ 11,383.1	$ 11,149.3	$ 12,093.3	$ 13,101.3
Operating income	957.7	774.2	819.9	915.5
Net income	755.3	553.3	592.8	705.7
Net income attributable to limited partners	753.5	552.5	592.0	698.9
Earnings per unit:				
Basic	$ 0.85	$ 0.62	$ 0.66	$ 0.77
Diluted	$ 0.83	$ 0.60	$ 0.64	$ 0.75
For the Year Ended December 31, 2012:				
Revenues	$ 11,252.5	$ 9,789.8	$ 10,468.7	$ 11,072.1
Operating income	748.9	749.1	788.5	822.7
Net income	655.5	567.2	587.9	617.4
Net income attributable to limited partners	651.3	566.3	586.8	615.5
Earnings per unit:				
Basic	$ 0.76	$ 0.66	$ 0.68	$ 0.70
Diluted	$ 0.73	$ 0.64	$ 0.66	$ 0.68

The sum of our quarterly earnings per unit amounts may not equal our full year amounts due to slight rounding differences.

Note 21. Condensed Consolidating Financial Information

EPO conducts all of our business. Currently, we have no independent operations and no material assets outside those of EPO.

EPO has issued publicly traded debt securities. Enterprise Products Partners L.P., as the parent company of EPO, guarantees the debt obligations of EPO, with the exception of the remaining debt obligations of TEPPCO. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full and unconditional repayment of that obligation. EPO's consolidated subsidiaries have no significant restrictions on their ability to pay distributions or make loans to Enterprise Products Partners L.P. See Note 11 for additional information regarding our consolidated debt obligations.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Condensed Consolidating Balance Sheet
December 31, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	$ 93.9	$ 49.5	$ (20.9)	$ 122.5	$ --	$ --	$ 122.5
Accounts receivable – trade, net	1,986.8	3,491.1	(2.4)	5,475.5	--	--	5,475.5
Accounts receivable – related parties	384.7	1,348.1	(1,726.0)	6.8	0.2	(0.2)	6.8
Inventories	948.5	145.4	(0.8)	1,093.1	--	--	1,093.1
Prepaid and other current assets	140.9	191.4	(6.8)	325.5	--	--	325.5
Total current assets	3,554.8	5,225.5	(1,756.9)	7,023.4	0.2	(0.2)	7,023.4
Property, plant and equipment, net	1,945.0	24,999.7	1.9	26,946.6	--	--	26,946.6
Investments in unconsolidated affiliates	30,819.9	2,921.2	(31,304.0)	2,437.1	15,214.5	(15,214.5)	2,437.1
Intangible assets, net	76.9	1,385.3	--	1,462.2	--	--	1,462.2
Goodwill	458.9	1,621.1	--	2,080.0	--	--	2,080.0
Other assets	123.5	67.2	(1.4)	189.3	0.1	--	189.4
Total assets	$ 36,979.0	$ 36,220.0	$ (33,060.4)	$ 40,138.6	$ 15,214.8	$ (15,214.7)	$ 40,138.7
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 1,125.0	$ --	$ --	$ 1,125.0	$ --	$ --	$ 1,125.0
Accounts payable – trade	103.0	641.6	(20.9)	723.7	--	--	723.7
Accounts payable – related parties	1,541.8	333.8	(1,724.9)	150.7	--	(0.2)	150.5
Accrued product payables	2,388.6	3,224.5	(4.4)	5,608.7	--	--	5,608.7
Accrued interest	304.2	0.1	--	304.3	--	--	304.3
Other current liabilities	92.3	242.4	(6.7)	328.0	--	(1.5)	326.5
Total current liabilities	5,554.9	4,442.4	(1,756.9)	8,240.4	--	(1.7)	8,238.7
Long-term debt	16,211.5	15.0	--	16,226.5	--	--	16,226.5
Deferred tax liabilities	4.3	55.0	(1.4)	57.9	--	2.9	60.8
Other long-term liabilities	11.9	160.4	--	172.3	--	--	172.3
Commitments and contingencies							
Equity:							
Partners’ and other owners’ equity	15,196.4	31,475.9	(31,482.4)	15,189.9	15,214.8	(15,189.9)	15,214.8
Noncontrolling interests	--	71.3	180.3	251.6	--	(26.0)	225.6
Total equity	15,196.4	31,547.2	(31,302.1)	15,441.5	15,214.8	(15,215.9)	15,440.4
Total liabilities and equity	$ 36,979.0	$ 36,220.0	$ (33,060.4)	$ 40,138.6	$ 15,214.8	$ (15,214.7)	$ 40,138.7

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Condensed Consolidating Balance Sheet
December 31, 2012

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	$ 4.3	$ 28.0	$ (12.1)	$ 20.2	$ 0.2	$ --	$ 20.4
Accounts receivable – trade, net	1,585.2	2,768.7	(3.0)	4,350.9	--	--	4,350.9
Accounts receivable – related parties	180.5	1,372.8	(1,550.8)	2.5	(0.6)	0.6	2.5
Inventories	853.6	235.6	(0.8)	1,088.4	--	--	1,088.4
Prepaid and other current assets	154.9	231.8	(5.8)	380.9	--	--	380.9
Total current assets	2,778.5	4,636.9	(1,572.5)	5,842.9	(0.4)	0.6	5,843.1
Property, plant and equipment, net	1,673.6	23,170.8	2.0	24,846.4	--	--	24,846.4
Investments in unconsolidated affiliates	28,454.4	1,846.9	(28,906.7)	1,394.6	13,188.0	(13,188.0)	1,394.6
Intangible assets, net	78.5	1,488.3	--	1,566.8	--	--	1,566.8
Goodwill	458.9	1,627.9	--	2,086.8	--	--	2,086.8
Other assets	126.0	71.4	(0.9)	196.5	0.2	--	196.7
Total assets	$ 33,569.9	$ 32,842.2	$ (30,478.1)	$ 35,934.0	$ 13,187.8	$ (13,187.4)	$ 35,934.4
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 1,516.7	$ 29.9	$ --	$ 1,546.6	$ --	$ --	$ 1,546.6
Accounts payable – trade	226.7	549.8	(12.1)	764.4	0.1	--	764.5
Accounts payable – related parties	1,584.2	92.9	(1,550.6)	126.5	--	0.6	127.1
Accrued product payables	1,851.8	2,628.4	(4.0)	4,476.2	--	--	4,476.2
Accrued interest	300.1	0.7	--	300.8	--	--	300.8
Other current liabilities	266.5	280.0	(5.8)	540.7	--	(0.2)	540.5
Total current liabilities	5,746.0	3,581.7	(1,572.5)	7,755.2	0.1	0.4	7,755.7
Long-term debt	14,640.2	15.0	--	14,655.2	--	--	14,655.2
Deferred tax liabilities	5.1	17.7	(0.9)	21.9	--	0.6	22.5
Other long-term liabilities	15.6	189.4	--	205.0	--	--	205.0
Commitments and contingencies							
Equity:							
Partners’ and other owners’ equity	13,163.0	28,963.7	(28,961.1)	13,165.6	13,187.7	(13,165.6)	13,187.7
Noncontrolling interests	--	74.7	56.4	131.1	--	(22.8)	108.3
Total equity	13,163.0	29,038.4	(28,904.7)	13,296.7	13,187.7	(13,188.4)	13,296.0
Total liabilities and equity	$ 33,569.9	$ 32,842.2	$ (30,478.1)	$ 35,934.0	$ 13,187.8	$ (13,187.4)	$ 35,934.4

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 30,007.4	$ 31,641.3	$ (13,921.7)	$ 47,727.0	$ --	$ --	$ 47,727.0
Costs and expenses:							
Operating costs and expenses	29,176.7	28,983.7	(13,921.7)	44,238.7	--	--	44,238.7
General and administrative costs	29.1	157.0	--	186.1	2.2	--	188.3
Total costs and expenses	29,205.8	29,140.7	(13,921.7)	44,424.8	2.2	--	44,427.0
Equity in income of unconsolidated affiliates	2,609.0	204.8	(2,646.5)	167.3	2,599.1	(2,599.1)	167.3
Operating income	3,410.6	2,705.4	(2,646.5)	3,469.5	2,596.9	(2,599.1)	3,467.3
Other income (expense):							
Interest expense	(800.8)	(1.7)	--	(802.5)	--	--	(802.5)
Other, net	0.3	(0.5)	--	(0.2)	--	--	(0.2)
Total other expense, net	(800.5)	(2.2)	--	(802.7)	--	--	(802.7)
Income before income taxes	2,610.1	2,703.2	(2,646.5)	2,666.8	2,596.9	(2,599.1)	2,664.6
Benefit from (provision for) income taxes	(13.9)	(42.6)	--	(56.5)	--	(1.0)	(57.5)
Net income	2,596.2	2,660.6	(2,646.5)	2,610.3	2,596.9	(2,600.1)	2,607.1
Net income attributable to noncontrolling interests	--	(1.2)	(12.9)	(14.1)	--	3.9	(10.2)
Net income attributable to entity	$ 2,596.2	$ 2,659.4	$ (2,659.4)	$ 2,596.2	$ 2,596.9	$ (2,596.2)	$ 2,596.9

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2012

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 29,654.7	$ 28,221.5	$ (15,293.1)	$ 42,583.1	$ --	$ --	$ 42,583.1
Costs and expenses:							
Operating costs and expenses	28,839.1	25,821.8	(15,293.0)	39,367.9	--	--	39,367.9
General and administrative costs	26.1	142.7	--	168.8	1.5	--	170.3
Total costs and expenses	28,865.2	25,964.5	(15,293.0)	39,536.7	1.5	--	39,538.2
Equity in income of unconsolidated affiliates	2,381.8	80.7	(2,398.2)	64.3	2,421.4	(2,421.4)	64.3
Operating income	3,171.3	2,337.7	(2,398.3)	3,110.7	2,419.9	(2,421.4)	3,109.2
Other income (expense):							
Interest expense	(767.1)	(4.7)	--	(771.8)	--	--	(771.8)
Other, net	0.1	73.3	--	73.4	--	--	73.4
Total other expense, net	(767.0)	68.6	--	(698.4)	--	--	(698.4)
Income before income taxes	2,404.3	2,406.3	(2,398.3)	2,412.3	2,419.9	(2,421.4)	2,410.8
Provision for income taxes	15.7	2.4	--	18.1	--	(0.9)	17.2
Net income	2,420.0	2,408.7	(2,398.3)	2,430.4	2,419.9	(2,422.3)	2,428.0
Net loss (income) attributable to noncontrolling interests	--	(5.1)	(5.3)	(10.4)	--	2.3	(8.1)
Net income attributable to entity	$ 2,420.0	$ 2,403.6	$ (2,403.6)	$ 2,420.0	$ 2,419.9	$ (2,420.0)	$ 2,419.9

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2011

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 33,063.8	$ 27,971.8	$ (16,722.6)	$ 44,313.0	$ --	$ --	$ 44,313.0
Costs and expenses:							
Operating costs and expenses	32,432.7	25,609.7	(16,723.9)	41,318.5	--	--	41,318.5
General and administrative costs	10.4	163.7	--	174.1	7.7	--	181.8
Total costs and expenses	32,443.1	25,773.4	(16,723.9)	41,492.6	7.7	--	41,500.3
Equity in income of unconsolidated affiliates	2,194.4	131.7	(2,279.7)	46.4	2,054.6	(2,054.6)	46.4
Operating income	2,815.1	2,330.1	(2,278.4)	2,866.8	2,046.9	(2,054.6)	2,859.1
Other income (expense):							
Interest expense	(725.1)	(26.4)	7.4	(744.1)	--	--	(744.1)
Other, net	7.8	0.1	(7.4)	0.5	--	--	0.5
Total other expense, net	(717.3)	(26.3)	--	(743.6)	--	--	(743.6)
Income before income taxes	2,097.8	2,303.8	(2,278.4)	2,123.2	2,046.9	(2,054.6)	2,115.5
Provision for income taxes	(45.3)	18.4	--	(26.9)	--	(0.3)	(27.2)
Net income	2,052.5	2,322.2	(2,278.4)	2,096.3	2,046.9	(2,054.9)	2,088.3
Net loss (income) attributable to noncontrolling interests	--	(51.7)	9.2	(42.5)	--	1.1	(41.4)
Net income attributable to entity	$ 2,052.5	$ 2,270.5	$ (2,269.2)	$ 2,053.8	$ 2,046.9	$ (2,053.8)	$ 2,046.9

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Comprehensive Income
For the Year Ended December 31, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 2,616.5	$ 2,651.6	$ (2,646.5)	$ 2,621.6	$ 2,608.3	$ (2,611.4)	$ 2,618.5
Comprehensive income attributable to noncontrolling interests	--	(1.2)	(12.9)	(14.1)	--	3.9	(10.2)
Comprehensive income attributable to entity	$ 2,616.5	$ 2,650.4	$ (2,659.4)	$ 2,607.5	$ 2,608.3	$ (2,607.5)	$ 2,608.3

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Comprehensive Income
For the Year Ended December 31, 2012

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 2,375.8	$ 2,433.9	$ (2,398.3)	$ 2,411.4	$ 2,400.9	$ (2,403.3)	$ 2,409.0
Comprehensive income attributable to noncontrolling interests	--	(5.1)	(5.3)	(10.4)	--	2.3	(8.1)
Comprehensive income attributable to entity	$ 2,375.8	$ 2,428.8	$ (2,403.6)	$ 2,401.0	$ 2,400.9	$ (2,401.0)	$ 2,400.9

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Comprehensive Income
For the Year Ended December 31, 2011

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 1,737.4	$ 2,319.4	$ (2,278.3)	$ 1,778.5	$ 1,729.1	$ (1,737.1)	$ 1,770.5
Comprehensive income attributable to noncontrolling interests	--	(51.7)	9.2	(42.5)	--	1.1	(41.4)
Comprehensive income attributable to entity	$ 1,737.4	$ 2,267.7	$ (2,269.1)	$ 1,736.0	$ 1,729.1	$ (1,736.0)	$ 1,729.1

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 2,596.2	$ 2,660.6	$ (2,646.5)	$ 2,610.3	$ 2,596.9	$ (2,600.1)	$ 2,607.1
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	143.5	1,072.8	1.3	1,217.6	--	--	1,217.6
Equity in income of unconsolidated affiliates	(2,609.0)	(204.8)	2,646.5	(167.3)	(2,599.1)	2,599.1	(167.3)
Distributions received from unconsolidated affiliates	4,523.2	233.7	(4,505.3)	251.6	2,454.4	(2,454.4)	251.6
Net effect of changes in operating accounts and other operating activities	(1,351.0)	1,323.4	(10.1)	(37.7)	(7.8)	2.0	(43.5)
Net cash flows provided by operating activities	3,302.9	5,085.7	(4,514.1)	3,874.5	2,444.4	(2,453.4)	3,865.5
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(517.8)	(2,864.4)	--	(3,382.2)	--	--	(3,382.2)
Proceeds from asset sales and insurance recoveries	59.6	221.0	--	280.6	--	--	280.6
Other investing activities	(3,163.6)	(769.5)	2,777.2	(1,155.9)	(1,791.1)	1,791.1	(1,155.9)
Cash used in investing activities	(3,621.8)	(3,412.9)	2,777.2	(4,257.5)	(1,791.1)	1,791.1	(4,257.5)
Financing activities:							
Borrowings under debt agreements	13,852.8	--	--	13,852.8	--	--	13,852.8
Repayments of debt	(12,650.8)	(29.8)	--	(12,680.6)	--	--	(12,680.6)
Cash distributions paid to partners	(2,453.4)	(4,514.1)	4,514.1	(2,453.4)	(2,400.4)	2,453.5	(2,400.3)
Cash distributions paid to noncontrolling interests	--	--	(8.9)	(8.9)	--	--	(8.9)
Cash contributions from noncontrolling interests	--	--	115.4	115.4	--	--	115.4
Net cash proceeds from the issuance of common units	--	--	--	--	1,792.0	--	1,792.0
Cash contributions from owners	1,791.2	2,892.6	(2,892.6)	1,791.2	--	(1,791.2)	--
Other financing activities	(192.5)	--	--	(192.5)	(45.1)	--	(237.6)
Cash provided by (used in) financing activities	347.3	(1,651.3)	1,728.0	424.0	(653.5)	662.3	432.8
Net change in cash and cash equivalents	28.4	21.5	(8.9)	41.0	(0.2)	--	40.8
Cash and cash equivalents, January 1	--	28.0	(12.1)	15.9	0.2	--	16.1
Cash and cash equivalents, December 31	$ 28.4	$ 49.5	$ (21.0)	$ 56.9	$ --	$ --	$ 56.9

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2012

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 2,420.0	$ 2,408.7	$ (2,398.3)	$ 2,430.4	$ 2,419.9	$ (2,422.3)	$ 2,428.0
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	118.0	986.9	--	1,104.9	--	--	1,104.9
Equity in income of unconsolidated affiliates	(2,381.8)	(80.7)	2,398.2	(64.3)	(2,421.4)	2,421.4	(64.3)
Distributions received from unconsolidated affiliates	3,918.9	106.6	(3,908.8)	116.7	2,209.3	(2,209.3)	116.7
Net effect of changes in operating accounts and other operating activities	(2,174.9)	1,485.3	(0.8)	(690.4)	(4.9)	0.9	(694.4)
Net cash flows provided by operating activities	1,900.2	4,906.8	(3,909.7)	2,897.3	2,202.9	(2,209.3)	2,890.9
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(219.5)	(3,379.0)	--	(3,598.5)	--	--	(3,598.5)
Proceeds from asset sales and insurance recoveries	1,137.2	61.6	--	1,198.8	--	--	1,198.8
Other investing activities	(2,961.4)	(432.3)	2,774.6	(619.1)	(816.2)	816.2	(619.1)
Cash used in investing activities	(2,043.7)	(3,749.7)	2,774.6	(3,018.8)	(816.2)	816.2	(3,018.8)
Financing activities:							
Borrowings under debt agreements	8,363.1	--	--	8,363.1	--	--	8,363.1
Repayments of debt	(6,666.9)	(9.5)	--	(6,676.4)	--	--	(6,676.4)
Cash distributions paid to partners	(2,209.3)	(3,922.1)	3,922.1	(2,209.3)	(2,178.6)	2,209.3	(2,178.6)
Cash distributions paid to noncontrolling interests	--	--	(13.3)	(13.3)	--	--	(13.3)
Cash contributions from noncontrolling interests	--	--	6.6	6.6	--	--	6.6
Net cash proceeds from the issuance of common units	--	--	--	--	816.8	--	816.8
Cash contributions from owners	816.2	2,781.2	(2,781.2)	816.2	--	(816.2)	--
Other financing activities	(169.3)	--	--	(169.3)	(24.7)	--	(194.0)
Cash provided by (used in) financing activities	133.8	(1,150.4)	1,134.2	117.6	(1,386.5)	1,393.1	124.2
Net change in cash and cash equivalents	(9.7)	6.7	(0.9)	(3.9)	0.2	--	(3.7)
Cash and cash equivalents, January 1	9.7	21.3	(11.2)	19.8	--	--	19.8
Cash and cash equivalents, December 31	$ --	$ 28.0	$ (12.1)	$ 15.9	$ 0.2	$ --	$ 16.1

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2011

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	**Other Subsidiaries (Non-guarantor)**	**EPO and Subsidiaries Eliminations and Adjustments**	**Consolidated EPO and Subsidiaries**	**Enterprise Products Partners L.P. (Guarantor)**	**Eliminations and Adjustments**	**Consolidated Total**
Operating activities:							
Net income	$ 2,052.5	$ 2,322.2	$ (2,278.4)	$ 2,096.3	$ 2,046.9	$ (2,054.9)	$ 2,088.3
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	119.7	888.7	(1.4)	1,007.0	--	--	1,007.0
Equity in income of unconsolidated affiliates	(2,194.4)	(131.7)	2,279.7	(46.4)	(2,054.6)	2,054.6	(46.4)
Distributions received from unconsolidated affiliates	150.3	196.8	(190.7)	156.4	1,994.9	(1,994.9)	156.4
Net effect of changes in operating accounts and other operating activities	1,036.4	(118.5)	(789.8)	128.1	(3.4)	0.5	125.2
Net cash flows provided by operating activities	1,164.5	3,157.5	(980.6)	3,341.4	1,983.8	(1,994.7)	3,330.5
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(63.4)	(3,779.2)	--	(3,842.6)	--	--	(3,842.6)
Proceeds from asset sales and insurance recoveries	611.5	442.3	--	1,053.8	--	--	1,053.8
Other investing activities	(1,991.7)	(1,312.6)	3,315.5	11.2	(546.9)	546.9	11.2
Cash used in investing activities	(1,443.6)	(4,649.5)	3,315.5	(2,777.6)	(546.9)	546.9	(2,777.6)
Financing activities:							
Borrowings under debt agreements	7,764.1	560.0	--	8,324.1	--	--	8,324.1
Repayments of debt	(5,970.0)	(1,405.8)	--	(7,375.8)	--	--	(7,375.8)
Cash distributions paid to partners	(1,994.9)	(946.8)	946.8	(1,994.9)	(1,974.3)	1,994.9	(1,974.3)
Cash distributions paid to noncontrolling interests	--	(108.1)	47.4	(60.7)	--	--	(60.7)
Cash contributions from noncontrolling interests	--	724.8	(716.1)	8.7	--	(0.2)	8.5
Net cash proceeds from the issuance of common units	--	--	--	--	542.9	--	542.9
Cash contributions from owners	546.9	2,621.3	(2,621.3)	546.9	--	(546.9)	--
Other financing activities	(57.8)	--	--	(57.8)	(5.5)	--	(63.3)
Cash provided by (used in) financing activities	288.3	1,445.4	(2,343.2)	(609.5)	(1,436.9)	1,447.8	(598.6)
Net change in cash and cash equivalents	9.2	(46.6)	(8.3)	(45.7)	--	--	(45.7)
Cash and cash equivalents, January 1	0.5	67.9	(2.9)	65.5	--	--	65.5
Cash and cash equivalents, December 31	$ 9.7	$ 21.3	$ (11.2)	$ 19.8	$ --	$ --	$ 19.8

EXHIBIT 10.18

Phantom Unit Grant with DERs
under the
2008 Enterprise Products Long-Term Incentive Plan
(Third Amendment and Restatement)

Date of Grant:______________________________
Name of Grantee: ___________________________
Number of Phantom Units Granted: _____________
Phantom Unit Grant Number: _________________

Enterprise Products Company (the "Company") is pleased to inform you that you have been granted under the 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) (the "Plan") the number of Phantom Units set forth above. A Phantom Unit is a contractual right to receive, on or following its vesting, a Common Unit of Enterprise Products Partners L.P. (the "Partnership"). Each Phantom Unit granted to you also has a tandem Distribution Equivalent Right ("DER") that entitles you to receive, on or as soon as reasonably practical following each Distribution Date (as defined below) on which the DER remains credited to you, an amount of cash equal to the cash distribution paid on a Common Unit on that Distribution Date. The terms of this grant are as follows:

1. Vesting/Forfeiture of Phantom Units and DERs. Subject to the further provisions of this agreement (this "Award Agreement"), (i) the Phantom Units hereby granted to you shall become vested on the Scheduled Vesting Dates in the percentages as set forth below or (ii) if you incur a Qualifying Termination (as defined below) prior to a Scheduled Vesting Date, the Phantom Units then remaining credited to you shall become 100% vested on the date of your Qualifying Termination.

SCHEDULED VESTING DATES	CUMULATIVE VESTED PERCENTAGE
[________], 20___	25%
[________], 20___	50%
[________], 20___	75%
[________], 20___	100%

Notwithstanding the above, if prior to a Scheduled Vesting Date you cease to be an Employee, Director and/or Consultant (as applicable) for any reason other than your Qualifying Termination, all Phantom Units and tandem DERs then remaining credited to you automatically shall terminate (without payment) on the date of your termination of service; provided, however, notwithstanding the foregoing, if your termination of service date is on or after a Record Date (as defined below) and before the next Distribution Date applicable to such Record Date, your DERs shall continue to be credited to you until the first date following that next Distribution Date, when they shall automatically terminate.

If a Phantom Unit becomes vested, its tandem DER automatically shall terminate concurrently with the payment of that vested Phantom Unit, except when the vested Phantom Unit is settled after the Record Date and before the next Distribution Date, in which case the DER in tandem with such vested Phantom Unit shall continue to be credited to you until the first date following the next Distribution Date, when it shall automatically terminate.

2. Payment of Vested Phantom Units. (a) If a Phantom Unit becomes vested, then, subject to the further provisions of this Section 2, you will be paid one Common Unit in the Qualified Month (as defined below) that is coincident with or next following the date of the vesting event.

(b) If, however, the vesting event is your Qualifying Termination pursuant to Section 5(j)(ii), then, notwithstanding paragraph (a), payment will be made in the first Qualified Month coincident with or next following the date your Required Release (as defined below) becomes effective; provided, however, if your Release Period spans two calendar years, payment will be made as follows: (i) if your Required Release becomes effective before January 1 of the second calendar year, payment will be made in the first Qualified Month in the second calendar year, and (ii) if your Required Release becomes effective in the second calendar year, payment will be made in the Qualified Month coincident with or next following the Required Release's effective date.

(c) If you are a "specified employee" for purposes of Section 409A of the Internal Revenue Code (the "Code") and payment hereunder upon your Qualifying Termination would subject you to the additional tax under Section 409A if the payment were made prior to the first date that is more than six months after your Qualifying Termination, such payment shall, instead, be paid to you in a lump sum (without interest) on the first business day that is more than six months after your Qualifying Termination, or on such earlier date, if any, as may be permitted by Section 409A without incurring such additional tax.

(d) Notwithstanding anything in this Section 2 to the contrary, in all events payment shall be made before the end of the 90-day period following the Scheduled Vesting Date or the date of the Qualifying Termination, whichever is applicable.

3. Payment of DERs. On or as soon as reasonably practical (and not later than 30 days) following each Distribution Date, you will receive, with respect to each DER that remains credited to you on such Distribution Date, a cash payment from the Company in an amount equal to the cash distribution paid with respect to a Common Unit on that Distribution Date.

4. No Transfers of Awards. None of the Phantom Units or tandem DERs hereby granted to you (or any interest therein) may be transferred, pledged, or encumbered by you in any manner, except by will or the laws of descent and distribution. If, in the event of your divorce, legal separation or other dissolution of your marriage, your spouse or former spouse is awarded ownership of, a division of any community property interest in, or any other interest in any of the Phantom Units or DERs granted to you hereunder, then, notwithstanding anything in Section 1 above to the contrary, effective concurrently with such award or division, such "awarded" or "divided" Phantom Units and DERs automatically shall be forfeited and cancelled without payment to any person.

5. Definitions. Capitalized terms used in this Award Agreement shall have their respective meanings as provided in the Plan, with the exception that the capitalized terms set forth below shall have the following meanings:

(a) "Affiliated Group" means and includes (individually, collectively or in any combination) (i) the Partnership, (ii) the Company, (iii) EPCO Holdings, Inc., (iv) Enterprise

Products Holdings LLC, (v) Enterprise Products OLPGP, Inc., (vi) Enterprise Products Operating LLC, (vii) Dan Duncan LLC, (viii) the respective subsidiaries, parent entities or affiliates of any of the foregoing entities, (ix) any other entity (A) which is controlled, directly or indirectly, individually, collectively or in any combination, by the Company or any of the foregoing entities or (B) in which the Company or any of the foregoing entities has a direct or indirect ownership interest, (x) any other entity (A) which is controlled, directly or indirectly, by The Estate of Dan L. Duncan, Deceased, Dan L. Duncan's descendants or any trusts for any of their respective benefit, individually, collectively or in any combination, or (B) in which any of them has a direct or indirect ownership interest, and (xi) any predecessors, subsidiaries, related entities, officers, directors, shareholders, parent entities, agents, attorneys, employees, successors, or assigns of any of the foregoing.

(b) "Applicable Fiscal Year" means and includes (i) each fiscal year of the Company ending on, or within one year following, the Change of Control and (ii) the last full fiscal year of the Company ending immediately prior to the Change of Control, if the annual bonus for such fiscal year has not been paid to you prior to such Change of Control.

(c) "Cause" means the occurrence of any of the following events:

(i) the commission by you of a material act of willful misconduct, including, but not limited to, the willful violation of any material law, rule, regulation of a governmental entity or cease and desist order applicable to you or any Affiliated Group member (other than a law, rule or regulation relating to a minor traffic violation or a similar offense, as determined by the Committee, in its discretion), or an act which constitutes a breach by you of a fiduciary duty owed to any Affiliated Group member; or

(ii) the commission by you of an act of dishonesty relating to the performance of your duties, your habitual unexcused absences from work, your willful failure to perform your duties in any material respect (other than any such failure resulting from your incapacity due to your physical or mental illness or disability), or your gross negligence in the performance or non-performance of your duties resulting in material damage or injury to any Affiliated Group member, its reputation or goodwill; provided, however, that in the event of your willful failure to perform your duties in any material respect, you shall be provided with written notice of such failure and be provided with a reasonable opportunity after such notice, in no event more than 30 days, to cure such failure to perform your duties; or

(iii) any conviction of you for, or plea by you of other than not guilty to, any misdemeanor involving dishonesty, fraud or breach of trust (other than for a minor traffic violation or a similar offense, as determined by the Committee in its discretion) or any felony, whether or not in the line of duty.

(d) "Change of Control" means the Duncan Interests shall cease, directly or indirectly, to control the General Partner (including for purposes of clarification, and without limitation, by control that may be deemed to exist based on (i) the facts that cause the Duncan Interests' deemed control of the General Partner to exist as of the date of this Award Agreement (which existing control you hereby acknowledge and agree to by acceptance of this grant) or (ii) the Duncan Interests' direct or indirect power to exercise a controlling influence over either the management or policies of the General Partner (as control and power are construed and used under rules and regulations promulgated by the SEC, including any presumptions used thereunder relating to control).

(e) "Distribution Date" means, with respect to a DER, a date on which a cash distribution is paid on a Common Unit and such date occurs while the DER remains credited to you hereunder.

(f) “Distribution Month” means a calendar month in which a Distribution Date occurs.

(g) “Duncan Interests” means, individually, collectively, or in any combination, The Estate of Dan L. Duncan, Deceased, Dan L. Duncan’s descendants, the heirs and/or legatees and/or distributees of Dan L. Duncan’s estate, and/or trusts (including, without limitation, one or more voting trusts) established for the benefit of Dan L. Duncan’s descendants, heirs and/or legatees and/or distributees.

(h) “Good Reason” means any nonconsensual (i) material reduction in your authority, duties or responsibilities as in effect immediately prior to the Change of Control, (ii) reduction of more than 20% in (A) the rate of your annual base salary as in effect immediately prior to the Change of Control or (B) the amount of the annual bonus paid to you after the Change of Control with respect to an Applicable Fiscal Year when compared to the amount of the annual bonus paid to you by the Affiliated Group members (on a collective basis) prior to the Change of Control with respect to the last full fiscal year of the Company ending prior to the Change of Control; provided, however, that if you were employed by the Affiliated Group members, collectively, for less than the full period of such last fiscal year, the bonus paid to you for such partial year shall be annualized for this purpose; provided, further, that if the annual bonus for any Applicable Fiscal Year is not paid to you within 90 days of the end of such Applicable Fiscal Year, then such failure shall be deemed a more than 20% reduction for purposes of determining Good Reason and deemed to have occurred within one year after the Change of Control, or (iii) change in your primary office location of more than 50 miles from its location on the date immediately prior to the Change of Control.

(i) “Qualified Month” means a calendar month during which the Partnership either (a) pays a cash distribution to holders of its Common Units or (b) is required to make adjustments to capital accounts upon the issuance of additional Common Units.

(j) “Qualifying Termination” means:

(i) you cease to be an Employee, Consultant or Director due to (1) your death or (2) your employment being terminated by an Affiliated Group member pursuant to its extended disability leave policy 12 months after you are determined to be disabled under its long-term disability plan; provided that your disability qualifies as a “disability” under Section 409A of the Code and you continue to be so disabled at the end of the extended 12-month disability leave period; or

(ii) you (1) cease to be an Employee, Consultant or Director due to your retirement on or after reaching age 62 and having 10 or more years of credited service as an Employee, Consultant and/or Director, (2) have given the Company at least 30 days prior written notice of your retirement date, unless such notice period is waived by the Company, in its sole discretion, (3) execute, within the Release Period, the Retirement and Release Agreement in the form required by the Company and such Retirement and Release Agreement becomes effective, and (4) comply, at the time of your retirement, with any applicable retirement policies then in effect; or

(iii) you cease to be an Employee, Consultant or Director due to either (1) the termination of your employment by an Affiliated Group member on or within one year after a Change of Control for any reason other than for Cause or (2) the termination of your employment by you for Good Reason within 120 days following the date on which you have actual notice of the event that gives rise to your termination for Good Reason, provided that such Good Reason event occurs on or within one year after the Change of Control.

If the Phantom Unit is subject to Section 409A of the Code, the Qualifying Termination must be a “separation from service” for purposes of Section 409A.

(k) “Record Date” means the date of record on which the Partnership determines the holder of a Common Unit for purposes of determining entitlement to receive the cash distribution that has been declared, but not yet paid, with respect to that Common Unit.

(l) “Release Period” means the 21-day or 45-day period, whichever is applicable, to your Required Release, as provided by 29 CFR §162.5.22(e).

(m) “Required Release” means your release of certain claims as provided in the Retirement and Release Agreement, which is required for your retirement to be a Qualifying Termination pursuant to Section 5(j)(ii).

6. No Right to Continued Service. Nothing in this Award Agreement or in the Plan shall confer any right on you to continue as an Employee, Director or Consultant. A change in your status between Employee, Director and/or Consultant shall not be a termination of your service for purposes of this Award Agreement.

7. Tax Withholding. Notwithstanding anything in this Award Agreement to the contrary, to the extent that the grant, vesting or settlement of a Phantom Unit or a DER, or any cash “distribution” payments made with respect to a DER, results in the receipt of compensation by you with respect to which an Affiliated Group member has a tax withholding obligation pursuant to any applicable law, then, unless other arrangements have been made by you in advance that are acceptable to such Affiliated Group member, the Affiliated Group member shall withhold (or cause to be withheld) from such settlement or payment (or other compensation owed you) such amount of money, number of Common Units or any combination thereof, in its discretion, as the Affiliated Group member determines is required to meet its tax withholding obligations under such applicable law.

8. Non-delivery of Common Units. Notwithstanding any other provisions of this Award Agreement to the contrary, no Affiliated Group member shall be obligated to deliver hereunder any Common Units if counsel to the Company, the Partnership or the General Partner determines such delivery would violate (i) any law or regulation of any governmental authority, (ii) any agreement between the Company, the General Partner or the Partnership and any national securities exchange or market upon which the Common Units are listed, or (iii) any policy of any Affiliated Group member.

9. Plan Controls. The Phantom Units and DERs hereby granted are subject to the terms of the Plan, which is hereby incorporated by reference, including, without limitation, the ability of the Committee, in its discretion, to amend this Award Agreement without your consent, as provided in the Plan. In the event of any conflict between the terms of this Award Agreement and the Plan, the Plan shall be the controlling document, with the sole exception that you shall not be considered an “at will” employee where the applicable state law governing your employment with the Affiliated Group member does not recognize the concept of employment “at will”. The Plan, as in effect on the Date of Grant, is attached hereto as Exhibit A.

10. Clawback. Notwithstanding any provision in this Award Agreement or the Plan to the contrary, by accepting this Award you agree that, to the extent required by any applicable law, including, without limitation, the requirements of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010, SEC rule or applicable securities exchange listing standards (collectively, the “Law”), the Phantom Units and all amounts paid or payable pursuant to or with respect to the Phantom Units, including all Common Units and DER amounts, shall be subject to forfeiture, recovery, recoupment and/or cancellation to the extent necessary to comply with such Law, and you agree to fully cooperate with the Company in complying with such Law. This Section 10 shall survive the expiration or termination of this Award Agreement for such period as is necessary to comply with the Law and effectuate any forfeiture, recovery, recoupment or cancellation.

11. Section 409A. Payments under this Award Agreement are intended to be exempt, to the maximum extent possible, from Section 409A of the Code, and, to the extent subject to Section 409A, to comply with Section 409A. This Award Agreement shall be construed and administered in accordance with this intent.

12. Governing Law. This Award Agreement will be construed and interpreted in accordance with the laws of the State of Delaware without regard to conflict of law principles.

ENTERPRISE PRODUCTS COMPANY

By: ______________________________
Senior Vice President, Human Resources

EXHIBIT 12.1

ENTERPRISE PRODUCTS PARTNERS L.P.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in millions)

	For the Year Ended December 31,				
	2013	**2012**	**2011**	**2010**	**2009**
Consolidated income	$ 2,607.1	$ 2,428.0	$ 2,088.3	$ 1,383.7	$ 1,140.3
Add: Provision for (benefit from) taxes	57.5	(17.2)	27.2	26.1	25.3
Less: Equity in earnings from unconsolidated affiliates	(167.3)	(64.3)	(46.4)	(62.0)	(92.3)
Consolidated pre-tax income before equity in earnings from unconsolidated affiliates	2,497.3	2,346.5	2,069.1	1,347.8	1,073.3
Add: Fixed charges	964.7	920.3	879.5	813.4	760.6
Amortization of capitalized interest	22.8	20.3	17.5	16.8	15.3
Distributed income of equity investees	251.6	116.7	156.4	191.9	169.3
Subtotal	3,736.4	3,403.8	3,122.5	2,369.9	2,018.5
Less: Capitalized interest	(133.0)	(116.8)	(106.7)	(47.2)	(53.1)
Net income attributable to noncontrolling interests	(10.2)	(8.1)	(20.5)	(25.5)	(26.4)
Total earnings	$ 3,593.2	$ 3,278.9	$ 2,995.3	$ 2,297.2	$ 1,939.0
Fixed charges:					
Interest expense	$ 802.5	$ 771.8	$ 744.1	$ 741.9	$ 687.3
Capitalized interest	133.0	116.8	106.7	47.2	53.1
Interest portion of rental expense	29.2	31.7	28.7	24.3	20.2
Total	$ 964.7	$ 920.3	$ 879.5	$ 813.4	$ 760.6
Ratio of earnings to fixed charges	3.7x	3.6x	3.4x	2.8x	2.6x

These computations take into account our consolidated operations and the distributed income from our equity method investees. For purposes of these calculations, "earnings" is the amount resulting from adding and subtracting the following items:

Add the following, as applicable:

- consolidated pre-tax income from continuing operations before adjustment for income or loss from equity investees;
- fixed charges;
- amortization of capitalized interest;
- distributed income of equity investees; and
- our share of pre-tax losses of equity investees for which charges arising from guarantees are included in fixed charges.

From the subtotal of the added items, subtract the following, as applicable:

- interest capitalized;
- preference security dividend requirements of consolidated subsidiaries; and
- the noncontrolling interests in pre-tax income of subsidiaries that have not incurred fixed charges.

The term "fixed charges" means the sum of the following: interest expensed and capitalized; amortized premiums, discounts and capitalized expenses related to indebtedness; an estimate of the interest within rental expense; and preference security dividend requirements of consolidated subsidiaries.

Exhibit 21.1

LIST OF SUBSIDIARIES
Enterprise Products Partners L.P.
as of February 1, 2014

Name of Subsidiary	**Jurisdiction of Formation**	**Effective Ownership**
Acadian Gas Pipeline System	Delaware	TXO-Acadian Gas Pipeline, LLC – 50% MCN Acadian Gas Pipeline, LLC – 50%
Acadian Gas, LLC	Delaware	Duncan Energy Partners L.P. – 100%
Adamana Land Company, LLC	Delaware	Enterprise Products Operating LLC – 100%
Arizona Gas Storage, L.L.C.	Delaware	Enterprise Arizona Gas, L.L.C. – 60% Third Party – 40%
Atlantis Offshore, LLC	Delaware	Manta Ray Gathering Company, L.L.C. – 50% Manta Ray Offshore Gathering Company, L.L.C. – 50%
Baton Rouge Fractionators LLC	Delaware	Enterprise Products Operating LLC – 32.25% Third Parties – 67.75%
Baton Rouge Pipeline LLC	Delaware	Baton Rouge Fractionators LLC – 100%
Baton Rouge Propylene Concentrator LLC	Delaware	Enterprise Products Operating LLC – 30% Third Parties – 70%
Belle Rose NGL Pipeline, L.L.C.	Delaware	Enterprise NGL Pipelines, LLC –41.67% Enterprise Products Operating LLC – 58.33%
Belvieu Environmental Fuels GP, LLC	Texas	Enterprise Products Operating LLC – 100%
Belvieu Environmental Fuels LLC	Texas	Enterprise Products Operating LLC – 99% Belvieu Environmental Fuels GP, LLC – 1%
Cajun Pipeline Company, LLC	Texas	Enterprise Products Operating LLC – 100%
Calcasieu Gas Gathering System	Texas	TXO-Acadian Gas Pipeline, LLC – 50% MCN Acadian Gas Pipeline, LLC – 50%
Cameron Highway Oil Pipeline Company	Delaware	Cameron Highway Pipeline I, L.P. – 50% Third Party – 50%
Cameron Highway Pipeline GP, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
Cameron Highway Pipeline I, L.P.	Delaware	Enterprise GTM Holdings L.P. – 99% Cameron Highway Pipeline GP, L.L.C. – 1%
Canadian Enterprise Gas Products, Ltd.	Alberta, Canada	Enterprise Products Operating LLC – 100%
Centennial Pipeline LLC	Delaware	Enterprise TE Products Pipeline Company, LLC – 50% Third Party – 50%
Chama Gas Services, LLC	Delaware	Enterprise New Mexico Ventures, LLC – 75% Third Party – 25%
Channelview Fleeting Services, L.L.C.	Texas	Enterprise Marine Services LLC – 100%
Chaparral Pipeline Company, LLC	Texas	Enterprise Midstream Companies LLC – 99.999% Enterprise NGL Pipelines II LLC – 0.001%
Chunchula Pipeline Company, LLC	Texas	Enterprise Products Operating LLC – 100%
CTCO of Texas, LLC	Texas	Enterprise Marine Services LLC – 100%
Cypress Gas Marketing, LLC	Delaware	Acadian Gas, LLC – 100%
Cypress Gas Pipeline, LLC	Delaware	Acadian Gas, LLC – 100%
Dean Pipeline Company, LLC	Texas	Enterprise Midstream Companies LLC – 99.999% Enterprise NGL Pipelines, LLC – 0.001%
Deep Gulf Development, LLC	Delaware	Enterprise Offshore Development, LLC – 100%
Deepwater Gateway, L.L.C.	Delaware	Enterprise Field Services, LLC – 50% Third Party – 50%
DEP Holdings, LLC	Delaware	Enterprise Products Operating LLC – 100%

Name of Subsidiary	Jurisdiction of Formation	Effective Ownership
DEP Offshore Port System, LLC	Texas	Duncan Energy Partners L.P. – 100%
Dixie Pipeline Company LLC	Delaware	Enterprise Products Operating LLC – 100%
Duncan Energy Partners L.P.	Delaware	Enterprise GTM Holdings L.P. – 99.299% DEP Holdings LLC – 0.700% Enterprise Products OLPGP, Inc. – 0.001%
Eagle Ford Pipeline LLC	Delaware	Enterprise Crude Pipeline LLC – 50% Third Party – 50%
ECO Property LLC	Delaware	Enterprise Crude Oil LLC – 100%
Energy Ventures, LLC	Colorado	Enterprise Crude Oil LLC – 100%
Enterprise Aggregation LLC	Delaware	Enterprise Crude Oil LLC – 100%
Enterprise Arizona Gas, LLC	Delaware	Enterprise Field Services, LLC – 100%
Enterprise Bakken LLC	Delaware	Enterprise Crude Oil LLC – 100%
Enterprise Big Thicket Pipeline System LLC	Texas	Enterprise GC LLC – 100%
Enterprise Bighorn LLC	Delaware	Enterprise Crude Oil LLC – 100%
Enterprise Crude GP LLC	Delaware	TCTM, L.P. – 100%
Enterprise Crude Oil LLC	Texas	TCTM, L.P. – 99.99% Enterprise Crude GP LLC – 0.01%
Enterprise Crude Pipeline LLC	Texas	TCTM, L.P. – 99.99% Enterprise Crude GP LLC – 0.01%
Enterprise Custom Marketing LLC	Delaware	Enterprise Crude Oil LLC – 100%
Enterprise EF78 LLC	Delaware	Enterprise Products Texas Operating LLC – 75% Third Party – 25%
Enterprise Energy LLC	Delaware	Enterprise Crude Oil LLC – 100%
Enterprise Field Services, LLC	Delaware	Enterprise GTM Holdings L.P. – 100%
Enterprise Fractionation, LLC	Delaware	Enterprise Products Operating LLC – 100%
Enterprise Gas Liquids LLC	Texas	Enterprise Products Operating LLC – 100%
Enterprise Gas Processing, LLC	Delaware	Enterprise Products Operating LLC – 100%
Enterprise Gathering II LLC	Delaware	Enterprise Products Operating LLC – 100%
Enterprise Gathering LLC	Delaware	Enterprise Products Operating LLC – 100%
Enterprise GC LLC	Delaware	Duncan Energy Partners L.P. – 100%
Enterprise GP LLC	Delaware	Enterprise TE Partners L.P. – 100%
Enterprise GTM Hattiesburg Storage, LLC	Delaware	Enterprise GTM Holdings L.P. – 100%
Enterprise GTM Holdings L.P.	Delaware	Enterprise Products Operating LLC – 99% Enterprise GTMGP, LLC – 1%
Enterprise GTM Offshore Operating Company, LLC	Delaware	Enterprise GTM Holdings L.P. – 100%
Enterprise GTMGP, LLC	Delaware	Enterprise Products GTM, LLC – 100%
Enterprise Hydrocarbons L.P.	Delaware	Enterprise Products Texas Operating LLC – 99% Enterprise Products Operating LLC – 1%
Enterprise Intrastate LLC	Delaware	Duncan Energy Partners L.P. – 100%
Enterprise Jonah Gas Gathering Company LLC	Delaware	Enterprise Products Operating LLC – 100%
Enterprise Logistic Services LLC (DBA Enterprise Transportation Company)	Texas	Enterprise Products Operating LLC – 100%
Enterprise Lou-Tex NGL Pipeline L.P.	Texas	Enterprise Products Operating LLC – 99% HSC Pipeline Partnership, LLC – 1%
Enterprise Lou-Tex Propylene Pipeline LLC	Texas	Duncan Energy Partners L.P. – 100%
Enterprise Louisiana Pipeline LLC	Texas	Enterprise Products Operating LLC – 100%
Enterprise Marine Services LLC	Delaware	Enterprise TE Partners L.P. – 100%

Name of Subsidiary	Jurisdiction of Formation	Effective Ownership
Enterprise Metering LLC	Delaware	Enterprise Crude Oil LLC – 100%
Enterprise Midstream Companies LLC	Texas	Enterprise TE Partners L.P. – 99.999% Enterprise GP LLC – 0.001%
Enterprise MT LLC	Delaware	Enterprise Crude Oil LLC – 100%
Enterprise ND LLC	Delaware	Enterprise Crude Oil LLC – 100%
Enterprise New Mexico Ventures, LLC	Delaware	Enterprise Field Services, LLC – 100%
Enterprise NGL Pipelines II LLC	Delaware	Enterprise Midstream Companies LLC – 100%
Enterprise NGL Pipelines, LLC	Delaware	Enterprise Products Operating LLC – 100%
Enterprise NGL Private Lines & Storage, LLC	Delaware	Enterprise Products Operating LLC – 100%
Enterprise Niobrara LLC	Delaware	Enterprise Crude Oil LLC – 100%
Enterprise NW Marketing LLC	Delaware	Enterprise Crude Oil LLC – 100%
Enterprise Offshore Development, LLC	Delaware	Moray Pipeline Company, LLC – 100%
Enterprise Offshore Port System, LLC	Texas	Enterprise Products Operating LLC – 100%
Enterprise Pathfinder, LLC	Delaware	Enterprise GTM Holdings L.P. – 100%
Enterprise Pelican Pipeline L.P.	Texas	Evangeline Gulf Coast Gas, LLC – 90% Evangeline Gas Corp. – 10%
Enterprise Petroleum LLC	Delaware	Enterprise Crude Oil LLC – 100%
Enterprise Plevna Marketing LLC	Delaware	Enterprise Crude Oil LLC – 100%
Enterprise Powder River LLC	Delaware	Enterprise Crude Oil LLC – 100%
Enterprise Products BBCT LLC	Texas	Enterprise Crude Oil LLC – 99.99% Enterprise Crude GP LLC – 0.01%
Enterprise Products GTM, LLC	Delaware	Enterprise Products Operating LLC – 100%
Enterprise Products Marketing Company LLC	Texas	Enterprise Products Operating LLC – 100%
Enterprise Products OLPGP, Inc.	Delaware	Enterprise Products Partners L.P. – 100%
Enterprise Products Operating LLC	Texas	Enterprise Products Partners L.P. – 99.999% Enterprise Products OLPGP, Inc. – 0.001%
Enterprise Products Pipeline Company LLC	Delaware	Enterprise Products Operating LLC – 100%
Enterprise Products Texas Operating LLC	Texas	Enterprise Products Operating LLC – 99% Enterprise Products OLPGP, Inc. – 1%
Enterprise Propane Terminals and Storage, LLC	Delaware	Enterprise Terminals & Storage, LLC – 100%
Enterprise Refined Products Company LLC	Delaware	Enterprise Products Operating LLC –100%
Enterprise Refined Products Marketing Company LLC	Delaware	Enterprise Refined Products Company LLC – 100%
Enterprise Rocky Mountain LLC	Delaware	Enterprise Crude Oil LLC – 100%
Enterprise Sage Marketing LLC	Delaware	Enterprise Crude Oil LLC – 100%
Enterprise Seaway L.P.	Delaware	Enterprise Crude Pipeline LLC – 99.99% Enterprise Crude GP LLC – 0.01%
Enterprise TE Investments LLC	Delaware	Enterprise Products Pipeline Company LLC – 100%
Enterprise TE Partners L.P.	Delaware	Enterprise Products Pipeline Company LLC – 2% Enterprise Products Operating LLC – 98%
Enterprise TE Products Pipeline Company LLC	Texas	Enterprise TE Partners L.P. – 99.999% Enterprise GP LLC – 0.001%
Enterprise Terminalling LLC	Texas	Enterprise Products Operating LLC – 99% Enterprise Gas Liquids LLC – 1%
Enterprise Terminals & Storage, LLC	Delaware	Mapletree, LLC – 100%
Enterprise Texas Pipeline LLC	Texas	Duncan Energy Partners L.P. – 100%
Enterprise Transload LLC	Delaware	Enterprise Crude Oil LLC – 100%
Enterprise White River Hub, LLC	Delaware	Enterprise Products Operating LLC – 100%
Enterprise Williston Basin LLC	Delaware	Enterprise Crude Oil LLC – 100%

Name of Subsidiary	Jurisdiction of Formation	Effective Ownership
Enterprise WY LLC	Delaware	Enterprise Crude Oil LLC – 100%
Evangeline Gas Corp.	Delaware	Evangeline Gulf Coast Gas, LLC – 100%
Evangeline Gulf Coast Gas, LLC	Delaware	Acadian Gas, LLC – 100%
Flextrend Development Company, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
Front Range Pipeline LLC	Delaware	Enterprise Products Operating LLC – 33.33% Third Parties – 66.67%
Groves RGP Pipeline LLC	Texas	Enterprise Products Operating LLC – 99% Enterprise Products Texas Operating LLC – 1%
High Island Offshore System, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
HSC Pipeline Partnership, LLC	Texas	Enterprise Products Operating LLC – 99% Enterprise Products OLPGP, Inc. – 1%
Independence Hub, LLC	Delaware	Enterprise Field Services, LLC – 80% Third Party – 20%
JMRS Transport Services, Inc.	Delaware	Enterprise Logistic Services LLC – 100%
K/D/S Promix, L.L.C.	Delaware	Enterprise Fractionation, LLC – 50% Third Parties – 50%
La Porte Pipeline Company, L.P.	Texas	Enterprise Products Operating LLC – 49.5% La Porte Pipeline GP, LLC – 1.0% Third Party – 49.5%
La Porte Pipeline GP, L.L.C.	Delaware	Enterprise Products Operating LLC – 50% Third Party – 50%
Manta Ray Gathering Company, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
Manta Ray Offshore Gathering Company, L.L.C.	Delaware	Neptune Pipeline Company, L.L.C. – 100%
Mapletree, LLC	Delaware	Enterprise Products Operating LLC – 100%
MCN Acadian Gas Pipeline, LLC	Delaware	Acadian Gas, LLC – 100%
MCN Pelican Interstate Gas, LLC	Delaware	Acadian Gas, LLC – 100%
Mid-America Pipeline Company, LLC	Delaware	Mapletree, LLC – 100%
Mont Belvieu Caverns, LLC	Delaware	Duncan Energy Partners L.P. – 100%
Moray Pipeline Company, L.L.C.	Delaware	Enterprise Products Operating LLC – 100%
Nautilus Pipeline Company, L.L.C.	Delaware	Neptune Pipeline Company, L.L.C. – 100%
Neches Pipeline System	Delaware	TXO-Acadian Gas Pipeline, LLC – 50% MCN Acadian Gas Pipeline, LLC – 50%
Nemo Gathering Company, LLC	Delaware	Moray Pipeline Company, LLC – 33.92% Third Party – 66.08%
Neptune Pipeline Company, L.L.C.	Delaware	Sailfish Pipeline Company, L.L.C. – 25.67% Third Parties – 74.33%
Norco-Taft Pipeline, LLC	Delaware	Enterprise NGL Private Lines & Storage, LLC – 100%
Olefins Terminal LLC	Delaware	Enterprise Products Operating LLC – 100%
Panola Pipeline Company, LLC	Texas	Enterprise Midstream Companies LLC – 99.999% Enterprise NGL Pipelines II LLC – 0.001%
Pontchartrain Natural Gas System	Texas	TXO-Acadian Gas Pipeline, LLC – 50% MCN Acadian Gas Pipeline, LLC – 50%
Port Neches GP LLC	Texas	Enterprise Products Operating LLC – 100%
Port Neches Pipeline LLC	Texas	Enterprise Products Operating LLC – 99% Port Neches GP LLC – 1%
Poseidon Oil Pipeline Company, L.L.C.	Delaware	Poseidon Pipeline Company, L.L.C. – 36% Third Parties – 64%
Poseidon Pipeline Company, L.L.C.	Delaware	Enterprise GTM Holdings L.P. – 100%
QP-LS, LLC	Wyoming	Enterprise Products BBCT LLC – 100%

Name of Subsidiary	Jurisdiction of Formation	Effective Ownership
Quanah Pipeline Company, LLC	Texas	Enterprise Midstream Companies LLC – 99.999% Enterprise NGL Pipelines II LLC – 0.001%
Rio Grande Pipeline Company	Texas	Enterprise Products Operating LLC – 70% Third Party – 30%
Rugged West Services LLC	Delaware	Enterprise Crude Oil LLC – 100%
Sabine Propylene Pipeline LLC	Texas	Duncan Energy Partners L.P. – 100%
Sailfish Pipeline Company, L.L.C.	Delaware	Enterprise Products Operating LLC – 100%
Seaway Crude Pipeline Company LLC	Delaware	Enterprise Seaway L.P. – 50% Third Parties – 50%
Seminole Pipeline Company LLC	Delaware	Enterprise Products Operating LLC – 100%
Skelly-Belvieu Pipeline Company, L.L.C.	Delaware	Enterprise Products Operating LLC – 50% Third Party – 50%
Sorrento Pipeline Company, LLC	Texas	Enterprise Products Operating LLC – 100%
South Texas NGL Pipelines, LLC	Delaware	Duncan Energy Partners L.P. – 100%
Southeast Keathley Canyon Pipeline Company, L.L.C.	Delaware	Enterprise Field Services, LLC – 50% Third Party – 50%
TCTM, L.P.	Delaware	Enterprise TE Partners L.P. – 99.999% Enterprise GP LLC – 0.001%
TECO Gas Gathering LLC	Delaware	Enterprise Products Operating LLC – 100%
TECO Gas Processing LLC	Delaware	Enterprise Products Operating LLC – 100%
Tejas-Magnolia Energy, LLC	Delaware	Pontchartrain Natural Gas System – 96.6% MCN Pelican Interstate Gas, LLC – 3.4%
TEPPCO O/S Port System, LLC	Texas	Enterprise Crude GP LLC – 100%
Texas Express Gathering LLC	Delaware	Enterprise Products Operating LLC – 45% Third Parties – 55%
Texas Express Pipeline LLC	Delaware	Enterprise Products Operating LLC – 35% Third Parties – 65%
Transport 4, L.L.C.	Delaware	Enterprise TE Products Pipeline Company LLC – 25% Third Parties – 75%
Tri-States NGL Pipeline, L.L.C.	Delaware	Enterprise Products Operating LLC – 50% Enterprise NGL Pipelines, LLC – 33.3% Third Party – 16.67%
TXO-Acadian Gas Pipeline, LLC	Delaware	Acadian Gas, LLC – 100%
Venice Energy Services Company, L.L.C.	Delaware	Enterprise Gas Processing LLC – 13.1% Third Parties – 86.99%
White River Hub, LLC	Delaware	Enterprise White River Hub, LLC – 50% Third Party – 50%
Wilcox Pipeline Company, LLC	Texas	Enterprise Midstream Companies LLC – 99.999% Enterprise NGL Pipelines II LLC – 0.001%
Wilprise Pipeline Company, L.L.C.	Delaware	Enterprise Products Operating LLC – 74.7% Third Party – 25.3%

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in (i) Registration Statement Nos. 333-36856, 333-115633, 333-150680, 333-176718, 333-191515, and 333-191516 of Enterprise Products Partners L.P. on Form S-8; (ii) Registration Statement No. 333-189050 of Enterprise Products Partners L.P. and Enterprise Products Operating LLC on Form S-3; and (iii) Registration Statement Nos. 333-165450 and 333-191514 of Enterprise Products Partners L.P. on Form S-3 of our reports dated March 3, 2014, relating to the consolidated financial statements of Enterprise Products Partners L.P. and subsidiaries and the effectiveness of Enterprise Products Partners L.P. and subsidiaries' internal control over financial reporting, appearing in this Annual Report on Form 10-K of Enterprise Products Partners L.P. for the year ended December 31, 2013.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 3, 2014

EXHIBIT 31.1

SARBANES-OXLEY SECTION 302 CERTIFICATION

I, Michael A. Creel, certify that:

1. I have reviewed this annual report on Form 10-K of Enterprise Products Partners L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 3, 2014

/s/ Michael A. Creel

Name: Michael A. Creel
Title: Chief Executive Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.

EXHIBIT 31.2

SARBANES-OXLEY SECTION 302 CERTIFICATION

I, W. Randall Fowler, certify that:

1. I have reviewed this annual report on Form 10-K of Enterprise Products Partners L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 3, 2014

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Financial Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF MICHAEL A. CREEL, CHIEF EXECUTIVE OFFICER OF ENTERPRISE PRODUCTS HOLDINGS LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this annual report of Enterprise Products Partners L.P. (the "Registrant") on Form 10-K for the year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael A. Creel, Chief Executive Officer of Enterprise Products Holdings LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ Michael A. Creel

Name: Michael A. Creel
Title: Chief Executive Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.

Date: March 3, 2014

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF W. RANDALL FOWLER, CHIEF FINANCIAL OFFICER OF ENTERPRISE PRODUCTS HOLDINGS LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this annual report of Enterprise Products Partners L.P. (the “Registrant”) on Form 10-K for the year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Randall Fowler, Chief Financial Officer of Enterprise Products Holdings LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Financial Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.

Date: March 3, 2014