

ENTERPRISE PRODUCTS PARTNERS L P

Form 10-Q

May 09, 2014

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, DC 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2014

OR

○ 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
 (I.R.S.
(State or Other Employer
Jurisdiction of Identification
 No.)

Incorporation or
Organization)

1100 Louisiana
Street, 10th Floor
Houston, Texas
77002

(Address of
Principal
Executive Offices,
including Zip
Code)

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

Edgar Filing: ENTERPRISE PRODUCTS PARTNERS L P - Form 10-Q

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes No

Indicate by check mark 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
Non-accelerated filer (Do not check if a smaller reporting company) Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes No

There were 937,005,117 common units of Enterprise Products Partners L.P. outstanding at April 30, 2014. Our common units trade on the New York Stock Exchange under the ticker symbol "EPD."

ENTERPRISE PRODUCTS PARTNERS L.P.
TABLE OF CONTENTS

	Page No.
<u>PART I. FINANCIAL INFORMATION.</u>	
<u>Item 1. Financial Statements.</u>	
<u>Unaudited Condensed Consolidated Balance Sheets</u>	<u>2</u>
<u>Unaudited Condensed Statements of Consolidated Operations</u>	<u>3</u>
<u>Unaudited Condensed Statements of Consolidated Comprehensive Income</u>	<u>4</u>
<u>Unaudited Condensed Statements of Consolidated Cash Flows</u>	<u>5</u>
<u>Unaudited Condensed Statements of Consolidated Equity</u>	<u>6</u>
<u>Notes to Unaudited Condensed Consolidated Financial Statements:</u>	
<u>1. Partnership Operations and Organization</u>	<u>7</u>
<u>2. General Accounting Matters</u>	<u>8</u>
<u>3. Equity-based Awards</u>	<u>9</u>
<u>4. Derivative Instruments, Hedging Activities and Fair Value Measurements</u>	<u>12</u>
<u>5. Inventories</u>	<u>20</u>
<u>6. Property, Plant and Equipment</u>	<u>20</u>
<u>7. Investments in Unconsolidated Affiliates</u>	<u>22</u>
<u>8. Intangible Assets and Goodwill</u>	<u>23</u>
<u>9. Debt Obligations</u>	<u>25</u>
<u>10. Equity and Distributions</u>	<u>27</u>
<u>11. Business Segments</u>	<u>29</u>
<u>12. Related Party Transactions</u>	<u>33</u>
<u>13. Earnings Per Unit</u>	<u>34</u>
<u>14. Commitments and Contingencies</u>	<u>34</u>
<u>15. Insurance Matters</u>	<u>36</u>
<u>16. Supplemental Cash Flow Information</u>	<u>36</u>
<u>17. Condensed Consolidating Financial Information</u>	<u>37</u>
<u>Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.</u>	<u>44</u>
<u>Item 3. Quantitative and Qualitative Disclosures about Market Risk.</u>	<u>63</u>
<u>Item 4. Controls and Procedures.</u>	<u>67</u>
<u>PART II. OTHER INFORMATION.</u>	
<u>Item 1. Legal Proceedings.</u>	<u>67</u>
<u>Item 1A. Risk Factors.</u>	<u>68</u>
<u>Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.</u>	<u>68</u>
<u>Item 3. Defaults Upon Senior Securities.</u>	<u>69</u>
<u>Item 4. Mine Safety Disclosures.</u>	<u>69</u>
<u>Item 5. Other Information.</u>	<u>69</u>
<u>Item 6. Exhibits.</u>	<u>69</u>
<u>Signatures</u>	<u>77</u>

Table of Contents

PART I. FINANCIAL INFORMATION.

Item 1. Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.

UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in millions)

	March 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	\$988.4	\$56.9
Restricted cash	43.3	65.6
Accounts receivable – trade, net of allowance for doubtful accounts of \$10.6 at March 31, 2014 and \$7.5 at December 31, 2013	4,988.1	5,475.5
Accounts receivable – related parties	5.5	6.8
Inventories	977.9	1,093.1
Prepaid and other current assets	330.0	325.5
Total current assets	7,333.2	7,023.4
Property, plant and equipment, net	27,262.5	26,946.6
Investments in unconsolidated affiliates	2,706.4	2,437.1
Intangible assets, net of accumulated amortization of \$1,169.7 at March 31, 2014 and \$1,150.0 at December 31, 2013	1,434.4	1,462.2
Goodwill (see Note 8)	2,079.9	2,080.0
Other assets	174.1	189.4
Total assets	\$40,990.5	\$40,138.7
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 9)	\$900.0	\$1,125.0
Accounts payable – trade	750.5	723.7
Accounts payable – related parties	91.0	150.5
Accrued product payables	5,412.6	5,608.7
Accrued interest	172.1	304.3
Other current liabilities	295.8	326.5
Total current liabilities	7,622.0	8,238.7
Long-term debt (see Note 9)	17,467.8	16,226.5
Deferred tax liabilities	60.6	60.8
Other long-term liabilities	178.1	172.3
Commitments and contingencies (see Note 14)		
Equity: (see Note 10)		
Partners' equity:		
Limited partners:		
Common units (937,008,892 units outstanding at March 31, 2014 and 935,685,008 units outstanding at December 31, 2013)	15,783.2	15,573.8
Accumulated other comprehensive loss	(344.3)	(359.0)
Total partners' equity	15,438.9	15,214.8
Noncontrolling interests	223.1	225.6
Total equity	15,662.0	15,440.4

Total liabilities and equity	\$40,990.5	\$40,138.7
------------------------------	------------	------------

See Notes to Unaudited Condensed Consolidated Financial Statements.

2

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
 UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED OPERATIONS
 (Dollars in millions, except per unit amounts)

	For the Three Months Ended March 31,	
	2014	2013
Revenues:		
Third parties	\$12,874.4	\$11,377.2
Related parties	35.5	5.9
Total revenues (see Note 11)	12,909.9	11,383.1
Costs and expenses:		
Operating costs and expenses:		
Third parties	11,618.4	10,206.2
Related parties	262.1	214.2
Total operating costs and expenses	11,880.5	10,420.4
General and administrative costs:		
Third parties	23.0	19.7
Related parties	30.2	29.8
Total general and administrative costs	53.2	49.5
Total costs and expenses (see Note 11)	11,933.7	10,469.9
Equity in income of unconsolidated affiliates	56.5	44.5
Operating income	1,032.7	957.7
Other income (expense):		
Interest expense	(220.9)	(195.9)
Interest income	0.3	0.2
Other, net	(0.6)	(0.3)
Total other expense, net	(221.2)	(196.0)
Income before income taxes	811.5	761.7
Provision for income taxes	(4.8)	(6.4)
Net income	806.7	755.3
Net income attributable to noncontrolling interests (see Note 10)	(7.9)	(1.8)
Net income attributable to limited partners	\$798.8	\$753.5
Earnings per unit: (see Note 13)		
Basic earnings per unit	\$0.87	\$0.85
Diluted earnings per unit	\$0.85	\$0.83

See Notes to Unaudited Condensed Consolidated Financial Statements.

3

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
 UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED
 COMPREHENSIVE INCOME
 (Dollars in millions)

	For the Three Months Ended March 31,	
	2014	2013
Net income	\$806.7	\$755.3
Other comprehensive income (loss):		
Cash flow hedges:		
Commodity derivative instruments:		
Changes in fair value of cash flow hedges	(9.2)	(47.6)
Reclassification of losses to net income	16.0	7.3
Interest rate derivative instruments:		
Changes in fair value of cash flow hedges	--	6.7
Reclassification of losses to net income	7.9	5.9
Total cash flow hedges	14.7	(27.7)
Comprehensive income	821.4	727.6
Comprehensive income attributable to noncontrolling interests	(7.9)	(1.8)
Comprehensive income attributable to limited partners	\$813.5	\$725.8

See Notes to Unaudited Condensed Consolidated Financial Statements.

4

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS

(Dollars in millions)

	For the Three Months Ended March 31,	
	2014	2013
Operating activities:		
Net income	\$806.7	\$755.3
Reconciliation of net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	319.9	292.0
Non-cash asset impairment charges (see Note 4)	8.8	11.0
Equity in income of unconsolidated affiliates	(56.5)	(44.5)
Distributions received from unconsolidated affiliates	71.7	51.3
Net gains attributable to asset sales and insurance recoveries (see Note 16)	(89.6)	(63.9)
Deferred income tax expense (benefit)	0.2	(6.5)
Changes in fair market value of derivative instruments	(7.8)	12.3
Net effect of changes in operating accounts (see Note 16)	342.5	(8.0)
Other operating activities	8.2	0.9
Net cash flows provided by operating activities	1,404.1	999.9
Investing activities:		
Capital expenditures	(699.7)	(631.6)
Contributions in aid of construction costs	4.3	8.7
Decrease (increase) in restricted cash	22.3	(63.8)
Investments in unconsolidated affiliates	(284.7)	(291.4)
Proceeds from asset sales and insurance recoveries (see Note 16)	96.3	130.5
Other investing activities	--	0.4
Cash used in investing activities	(861.5)	(847.2)
Financing activities:		
Borrowings under debt agreements	4,181.5	6,174.6
Repayments of debt	(3,160.0)	(4,826.6)
Debt issuance costs	(15.9)	(17.3)
Monetization of interest rate derivative instruments (see Note 4)	--	(168.8)
Cash distributions paid to limited partners (see Note 10)	(639.2)	(577.6)
Cash distributions paid to noncontrolling interests (see Note 10)	(8.0)	(2.4)
Net cash proceeds from the issuance of common units	83.0	554.1
Other financing activities	(52.5)	(24.5)
Cash provided by financing activities	388.9	1,111.5
Net change in cash and cash equivalents	931.5	1,264.2
Cash and cash equivalents, January 1	56.9	16.1
Cash and cash equivalents, March 31	\$988.4	\$1,280.3

See Notes to Unaudited Condensed Consolidated Financial Statements.

5

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
 UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
 (See Note 10 for Unit History, Accumulated Other Comprehensive
 Income (Loss) and Noncontrolling Interests)
 (Dollars in millions)

	Partners' Equity			Total
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	
Balance, December 31, 2013	\$15,573.8	\$ (359.0)	\$ 225.6	\$15,440.4
Net income	798.8	--	7.9	806.7
Cash distributions paid to limited partners	(639.2)	--	--	(639.2)
Cash distributions paid to noncontrolling interests	--	--	(8.0)	(8.0)
Net cash proceeds from the issuance of common units	83.0	--	--	83.0
Amortization of fair value of equity-based awards	17.4	--	--	17.4
Cash flow hedges	--	14.7	--	14.7
Other	(50.6)	--	(2.4)	(53.0)
Balance, March 31, 2014	\$15,783.2	\$ (344.3)	\$ 223.1	\$15,662.0

	Partners' Equity			Total
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	
Balance, December 31, 2012	\$13,558.1	\$ (370.4)	\$ 108.3	\$13,296.0
Net income	753.5	--	1.8	755.3
Cash distributions paid to limited partners	(577.6)	--	--	(577.6)
Cash distributions paid to noncontrolling interests	--	--	(2.4)	(2.4)
Net cash proceeds from the issuance of common units	554.1	--	--	554.1
Amortization of fair value of equity-based awards	17.1	--	--	17.1
Cash flow hedges	--	(27.7)	--	(27.7)
Other	(24.6)	--	--	(24.6)
Balance, March 31, 2013	\$14,280.6	\$ (398.1)	\$ 107.7	\$13,990.2

See Notes to Unaudited Condensed Consolidated Financial Statements.

6

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED 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 UNAUDITED CONDENSED 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 privately held 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; and (iii) Richard H. Bachmann. 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 privately held 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, privately held affiliates of EPCO owned approximately 36.4% of our limited partner interests at March 31, 2014.

References to "TEPPCO" mean TEPPCO Partners, L.P. prior to its merger with one of our wholly owned subsidiaries in October 2009.

Note 1. Partnership Operations and Organization

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.

7

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED 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.

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 12 for information regarding the ASA and other related party matters.

Note 2. General Accounting Matters

Our results of operations for the three months ended March 31, 2014 are not necessarily indicative of results expected for the full year of 2014. In our opinion, the accompanying Unaudited Condensed Consolidated Financial Statements include all adjustments consisting of normal recurring accruals necessary for fair presentation. Although we believe the disclosures in these financial statements are adequate and make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP") have been condensed or omitted pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC").

These Unaudited Condensed Consolidated Financial Statements and the Notes thereto should be read in conjunction with the Audited Consolidated Financial Statements and Notes thereto included in our annual report on Form 10-K for the year ended December 31, 2013 (the "2013 Form 10-K") filed with the SEC on March 3, 2014.

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 14 for additional information regarding our contingencies.

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

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 4 for additional information regarding our derivative instruments.

Estimates

Preparing our consolidated financial statements in conformity with U.S. 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.

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 March 31, 2014 and December 31, 2013, our restricted cash amounts were \$43.3 million and \$65.6 million, respectively. See Note 4 for information regarding our derivative instruments and hedging activities.

Note 3. 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 compensation expense we recognized in connection with equity-based awards for the periods indicated:

For the Three
Months
Ended March
31,
2014 2013

Equity-classified awards:

Edgar Filing: ENTERPRISE PRODUCTS PARTNERS L P - Form 10-Q

Restricted common unit awards	\$11.6	\$16.6
Unit option awards	--	0.4
Phantom unit awards	5.8	--
Liability-classified awards	0.1	0.2
Total	\$17.5	\$17.2

The fair value of equity-classified awards is amortized to earnings over the requisite service or vesting period.

Equity-classified awards are expected to result in the issuance of common units upon vesting. Compensation expense for liability-classified awards 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.

9

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

At March 31, 2014, 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"). Up to 7,000,000 of our common units may be issued as awards under the 1998 Plan. The maximum number of common units available for issuance under the 2008 Plan was 12,500,000 at March 31, 2014. This amount will automatically increase under the terms of the 2008 Plan by 2,500,000 common units on January 1, 2015 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. After giving effect to awards granted under the 1998 Plan and 2008 Plan through March 31, 2014, a total of 1,321,380 and 6,303,256 additional common units could be issued under these plans, respectively.

Restricted Common Unit Awards

Restricted common unit awards allow recipients to acquire our common units (at no cost to the recipient apart from fulfilling service and other conditions) once a defined vesting period expires, subject to customary forfeiture provisions. Restricted common unit awards generally vest at a rate of 25% per year beginning one year after the grant date and are non-vested until the required service periods expire. Restricted common units are included in the number of common units outstanding as presented on our Unaudited Condensed Consolidated Balance Sheets.

The following table presents information regarding restricted common unit awards for the period indicated:

	Number of Units	Weighted- Average Grant Date Fair Value per Unit (1)
Restricted common units at December 31, 2013	3,610,607	\$ 51.66
Vested	(1,239,862)	\$ 47.71
Forfeited	(86,650)	\$ 51.89
Restricted common units at March 31, 2014	2,284,095	\$ 53.80

(1) Determined by dividing the aggregate grant date fair value of awards (before an allowance for forfeitures) by the number of awards issued.

Each recipient of a restricted common unit award is 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 by Enterprise to its other common unitholders. These distributions are included in "Cash distributions paid to limited partners" as presented on our Unaudited Condensed Statements of Consolidated Cash Flows.

The following table presents supplemental information regarding our restricted common unit awards for the periods indicated:

For the Three
Months
Ended March
31,

	2014	2013
Cash distributions paid to restricted common unitholders	\$2.5	\$2.6
Total intrinsic value of restricted common unit awards that vested during period	\$81.4	\$52.4

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate \$57.3 million at March 31, 2014, of which our allocated share of the cost is currently estimated to be \$51.7 million. Due to the graded vesting provisions of these awards, 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 denominated in the common units of Enterprise Products Partners L.P. 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

10

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

option vesting on May 29, 2013 will expire on December 31, 2014). 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 following table presents unit option award activity for the period 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, 2013	2,025,000	\$ 26.49	1.3	\$ 57.0
Exercised	(1,300,000)	\$ 23.43		
Forfeited	(30,000)	\$ 32.27		
Unit option awards at March 31, 2014	695,000	\$ 31.95	1.7	\$ 26.0
Options exercisable at March 31, 2014	30,000	\$ 24.92	0.8	\$ 1.3

(1) Aggregate intrinsic value reflects fully vested unit option awards at the date indicated.

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 unit option awards during the periods indicated:

	For the Three Months Ended March 31,	
	2014	2013
Total intrinsic value of unit option awards exercised during period	\$54.7	\$16.4
Cash received from EPCO in connection with the exercise of unit option awards	\$31.8	\$9.5
Unit option award-related cash reimbursements to EPCO	\$54.7	\$16.4

As of March 31, 2014, all compensation expense related to unit option awards had been recognized.

Phantom Unit Awards

Phantom unit awards allow recipients to acquire our common units (at no cost to the recipient apart from fulfilling service and other conditions) once a defined vesting period expires, subject to customary forfeiture provisions.

Phantom unit awards generally vest at a rate of 25% per year beginning one year after the grant date and are non-vested until the required service periods expire.

At March 31, 2014, substantially all of our phantom unit awards are expected to result in the issuance of common units upon vesting; therefore, the applicable awards are accounted for as equity-classified awards. Compensation

expense attributable to these awards is based on the grant date fair value of the award, net of an allowance for estimated forfeitures, amortized over the requisite service or vesting period. The grant date fair value of a phantom unit award is based on the market price per unit of Enterprise's common units on the date of grant. These awards were first issued in February 2014.

11

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table presents phantom unit award activity for the period indicated:

	Number of Units	Weighted- Average Grant Date Fair Value per Unit (1)
Phantom unit awards at December 31, 2013	--	\$ --
Granted (2)	1,731,645	\$ 66.08
Forfeited	(7,250)	\$ 66.08
Phantom unit awards at March 31, 2014	1,724,395	\$ 66.08

(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 phantom unit awards issued during 2014 was \$114.4 million based on a grant date market price of our common units of \$66.08 per unit. An estimated annual forfeiture rate of 3.4% was applied to these awards.

Our long-term incentive plans provide for the issuance of distribution equivalent rights ("DERs") in connection with phantom unit awards. A DER entitles the participant to nonforfeitable cash payments equal to the product of the number of phantom unit awards outstanding for the participant and the cash distribution per common unit paid by Enterprise to its common unitholders. Cash payments made in connection with DERs are charged to partners' equity when the phantom unit award is expected to result in the issuance of common units; otherwise, such amounts are expensed. As of March 31, 2014, no cash payments have been made in connection with DERs.

For the EPCO group of companies, the unrecognized compensation cost associated with phantom unit awards was \$98.7 million at March 31, 2014, of which our allocated share of the cost is currently estimated to be \$91.2 million.

Due to the graded vesting provisions of these awards, we expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.4 years.

Note 4. 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.

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. The following table summarizes our portfolio of interest rate swaps at March 31, 2014:

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

In connection with the issuance of Senior Notes II and HH in March 2013, 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.

12

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 March 31, 2014 (volume measures as noted):

Derivative Purpose	Volume (1)		Accounting Treatment
	Current (2)	Long-Term (2)	
<u>Derivatives designated as hedging instruments:</u>			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	2.6	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls) (3)	0.9	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	0.1	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	2.5	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities (Bcf)	0.3	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	4.4	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	2.3	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	1.3	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.7	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)	4.8	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	6.9	n/a	Cash flow hedge
<u>Derivatives not designated as hedging instruments:</u>			
Natural gas risk management activities (Bcf) (4,5)	80.9	17.6	Mark-to-market
Refined products risk management activities (MMBbls) (5)	0.7	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (5)	15.8	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 March 2015, June 2014 and October 2016, respectively.

(3) Forecasted sales of NGL volumes under natural gas processing exclude 0.9 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.

(4) Current volumes include 41.4 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.

(5) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

At March 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.

13

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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			
	March 31, 2014		December 31, 2013		March 31, 2014		December 31, 2013	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
<u>Derivatives designated as hedging instruments</u>								
	Other current assets		Other current assets		Other current liabilities		Other current liabilities	
Interest rate derivatives		\$ 16.7		\$ 20.2		\$ --		\$ --
	Other assets		Other assets		Other liabilities		Other liabilities	
Interest rate derivatives		9.4		12.4		--		--
Total interest rate derivatives		26.1		32.6		--		--
	Other current assets		Other current assets		Other current liabilities		Other current liabilities	
Commodity derivatives		25.1		30.9		35.4		46.5
	Other assets		Other assets		Other liabilities		Other liabilities	
Commodity derivatives		--		--		--		0.3
Total commodity derivatives		25.1		30.9		35.4		46.8
Total derivatives designated as hedging instruments		\$ 51.2		\$ 63.5		\$ 35.4		\$ 46.8
<u>Derivatives not designated as hedging instruments</u>								
	Other current assets		Other current assets		Other current liabilities		Other current liabilities	
Interest rate derivatives		\$ --		\$ --		\$ 5.2		\$ 7.8
	Other assets		Other assets		Other liabilities		Other liabilities	
Interest rate derivatives		--		--		--		--
Total interest rate derivatives		--		--		5.2		7.8
	Other current assets		Other current assets		Other current liabilities		Other current liabilities	
Commodity derivatives		13.4		7.6		2.4		5.5
	Other assets		Other assets		Other liabilities		Other liabilities	
Commodity derivatives		1.3		2.8		0.5		2.8
Total commodity derivatives		14.7		10.4		2.9		8.3
Total derivatives not designated as hedging instruments		\$ 14.7		\$ 10.4		\$ 8.1		\$ 16.1

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 Assets Presented in the Balance Sheet (iii) = (i) – (ii)	Gross Amounts Offset in the Balance Sheet (ii)	Gross Amounts Not Offset in the Balance Sheet Cash Financial Instruments (iv)	Amounts That Would Have Been Presented On Net Basis (v) = (iii) + (iv)
As of March 31, 2014:				
Interest rate derivatives	\$ 26.1	\$ --	\$(1.7)	\$ 24.4
Commodity derivatives	39.8	--	(24.8)	15.0
As of December 31, 2013:				
Interest rate derivatives	\$ 32.6	\$ --	\$(2.6)	\$ 30.0
Commodity derivatives	41.3	--	(41.0)	0.3

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Offsetting of Financial Liabilities and Derivative Liabilities						
	Gross	Amounts	Gross Amounts	Amounts		
	Amounts	of	Not Offset	That		
	Offset in	Liabilities	in the Balance	Would		
	the	Presented	Sheet	Have		
	Balance	in the	Cash	Been		
	Recognized	Balance	Financial	On Net		
	Liabilities	Sheet	Instrument	Basis		
	Sheet	(iii) = (i) -	Paid	(v) = (iii)		
	(i)	(ii)	(iv)	+ (iv)		

As of March 31, 2014:

Interest rate derivatives	\$5.2	\$ --	\$ 5.2	\$(1.7)	\$ --	\$ 3.5
Commodity derivatives	38.3	--	38.3	(24.8)	(4.1)	9.4

As of December 31, 2013:

Interest rate derivatives	\$7.8	\$ --	\$ 7.8	\$(2.6)	\$ --	\$ 5.2
Commodity derivatives	55.1	--	55.1	(41.0)	(9.3)	4.8

Derivative assets and liabilities recorded on our Unaudited Condensed Consolidated Balance Sheets are presented on a gross-basis and determined at the individual transaction level. 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.

The following tables present the effect of our derivative instruments designated as fair value hedges on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative For the Three Months Ended March 31, 2014	2013
Interest rate derivatives	Interest expense	\$(2.9)	\$(3.5)
Commodity derivatives	Revenue	(0.4)	(0.7)
Total		\$(3.3)	\$(4.2)

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized
---	----------	------------------------

		in	
		Income on	
		Hedged Item	
		For the	
		Three	
		Months	
		Ended	
		March 31,	
		2014	2013
Interest rate derivatives	Interest expense	\$2.9	\$3.4
Commodity derivatives	Revenue	(1.4)	(6.7)
Total		\$1.5	\$(3.3)

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 Unaudited Condensed Consolidated Financial Statements during the periods presented.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following tables present the effect of our derivative instruments designated as cash flow hedges on our Unaudited Condensed Statements of Consolidated Operations and Unaudited Condensed 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 Three Months Ended March 31, 2014	2013
Interest rate derivatives	\$--	\$6.7
Commodity derivatives – Revenue (1)	(10.7)	(47.6)
Commodity derivatives – Operating costs and expenses (1)	1.5	--
Total	\$(9.2)	\$(40.9)

(1) The fair value of these derivative instruments would be reclassified to their respective locations on the Unaudited Condensed 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 Three Months Ended March 31, 2014	2013
Interest rate derivatives	Interest expense	\$(7.9)	\$(5.9)
Commodity derivatives	Revenue	(16.9)	(7.7)
Commodity derivatives	Operating costs and expenses	0.9	0.4

Total			\$(23.9)	\$(13.2)
			Gain (Loss)	
			Recognized	
			in Income on	
			Derivative	
Derivatives in Cash Flow			(Ineffective	
Hedging Relationships	Location		Portion)	
			For the Three	
			Months	
			Ended March	
			31,	
			2014	2013
Commodity derivatives	Revenue		\$ (0.1)	\$ --
Commodity derivatives	Operating costs and expenses		0.1	--
Total			\$ --	\$ --

Over the next twelve months, we expect to reclassify \$33.2 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 \$7.8 million of losses attributable to commodity derivative instruments from accumulated other comprehensive loss to earnings, \$9.0 million as a decrease in revenue and \$1.2 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 Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

			Gain (Loss)	
			Recognized in	
			Income on	
			Derivative	
Derivatives Not Designated			For the Three	
as Hedging Instruments	Location		Months	
			Ended March	
			31,	
			2014	2013
Interest rate derivatives	Interest expense		\$--	\$0.1
Commodity derivatives	Revenue		(21.0)	(5.3)
Total			\$(21.0)	\$(5.2)

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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.

Recurring Fair Value Measurements

The following tables set forth, by level within the fair value hierarchy, the carrying values of our financial assets and liabilities at March 31, 2014 and December 31, 2013. 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.

	March 31, 2014			
	Fair Value Measurements Using			
	Quoted			
	Prices			
	in			
	Active Significant			
	Markets			
	for	Other	Significant	Carrying
	Identical	Assets	Unobservable	Value
	and	Observable	Inputs	at March
	Liabilities	Inputs	Inputs	31,
	(Level			2014
	1)	(Level 2)	(Level 3)	
Financial assets:				
Interest rate derivatives	\$--	\$ 26.1	\$ --	\$ 26.1
Commodity derivatives	14.2	17.0	8.6	39.8
Total	\$14.2	\$ 43.1	\$ 8.6	\$ 65.9
Financial liabilities:				
Interest rate derivatives	\$--	\$ 5.2	\$ --	\$ 5.2
Commodity derivatives	20.2	17.2	0.9	38.3
Total	\$20.2	\$ 22.4	\$ 0.9	\$ 43.5

December 31, 2013
 Fair Value Measurements Using
 Quoted
 Prices
 in
 Active Significant
 Markets
 for Other Significant Carrying
 Identical Observable Unobservable Value
 Assets Observable Unobservable Value
 and
 Liabilities Inputs Inputs
 (Level
 1) (Level 2) (Level 3) 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

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table sets forth a reconciliation of changes in the fair values of our recurring Level 3 financial assets and liabilities on a combined basis for the periods indicated:

		For the Three Months Ended March 31, Location 2014 2013	
Financial asset (liability) balance, net, January 1		\$3.2	\$(1.5)
Total gains (losses) included in:			
Net income (1)	Revenue	4.6	(0.6)
Settlements	Revenue	(0.1)	1.5
Financial asset (liability) balance, net, March 31		\$7.7	\$(0.6)

(1) There were unrealized gains of \$4.5 million and \$0.9 million included in these amounts for the three months ended March 31, 2014 and 2013, respectively.

The following table provides quantitative information about our recurring Level 3 fair value measurements at March 31, 2014:

	Fair Value			Unobservable	
	Financial	Financial	Valuation	Input	Range
	Assets	Liabilities	Techniques		
Commodity derivatives – Crude oil	\$8.6	\$ 0.9	Discounted cash flow	Forward commodity prices	\$85.65-\$102.30/barrel

We believe forward commodity prices are the most significant unobservable inputs in determining our Level 3 recurring fair value measurements at March 31, 2014. 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.

Nonrecurring Fair Value Measurements

The following table summarizes our non-cash impairment charges by segment during each of the periods indicated:

	For the Three Months Ended March 31, 2014 2013	
NGL Pipelines & Services	\$2.6	\$1.0
Onshore Natural Gas Pipelines & Services	0.2	--
Onshore Crude Oil Pipelines & Services	1.0	--

Edgar Filing: ENTERPRISE PRODUCTS PARTNERS L P - Form 10-Q

Petrochemical & Refined Products Services	5.0	10.0
Total	\$8.8	\$11.0

These impairment charges are a component of operating costs and expenses on our Unaudited Condensed Statements of Consolidated Operations.

18

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

During the three months ended March 31, 2014, we recorded \$8.8 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 three months ended March 31, 2014:

	Carrying Value at March 31, 2014	Fair Value Measurements Using			Total Non-Cash Impairment Loss
		Quoted Prices in Active Markets	Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
Impairment of long-lived assets disposed of other than by sale	\$ --	\$--	\$ --	\$ --	\$ 3.8
Impairment of long-lived assets to be disposed of by sale	0.1	--	--	0.1	5.0
Total					\$ 8.8

During the three months ended March 31, 2013, we recorded \$11.0 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 three months ended March 31, 2013:

	Carrying Value at March 31, 2013	Fair Value Measurements Using			Total Non-Cash Impairment Loss
		Quoted Prices in Active Markets	Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
Impairment of long-lived assets disposed of other than by sale	\$ --	\$--	\$ --	\$ --	\$ 11.0

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 \$19.91 billion and \$18.4 billion at March 31, 2014 and December 31, 2013, respectively. The aggregate carrying value of these debt obligations was \$18.38 billion and

\$17.36 billion at March 31, 2014 and December 31, 2013, 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.

19

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 5. Inventories

Our inventory amounts by product type were as follows at the dates indicated:

	March 31, 2014	December 31, 2013
NGLs	\$276.3	\$ 593.8
Petrochemicals and refined products	399.3	395.1
Crude oil	287.9	42.6
Natural gas	14.4	61.6
Total	\$977.9	\$ 1,093.1

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. The following table presents our total cost of sales amounts and lower of cost or market adjustments for the periods indicated:

	For the Three Months Ended March 31,	
	2014	2013
Cost of sales (1)	\$11,052.7	\$9,692.5
Lower of cost or market adjustments	\$5.2	\$2.7

(1) Cost of sales is a component of "Operating costs and expenses," as presented on our Unaudited Condensed Statements of Consolidated Operations. Quarter-to-quarter fluctuations in these amounts are primarily due to changes in energy commodity prices and sales volumes associated with our marketing activities.

Note 6. 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	March 31, 2014	December 31, 2013
Plants, pipelines and facilities (1)	3-45 (6)	\$29,340.2	\$27,540.4
Underground and other storage facilities (2)	5-40 (7)	2,105.9	2,101.8
Platforms and facilities (3)	20-31	659.6	659.6
Transportation equipment (4)	3-10	140.5	138.9
Marine vessels (5)	15-30	759.6	744.8
Land		178.0	176.6

Construction in progress	1,419.1	2,655.5
Total	34,602.9	34,017.6
Less accumulated depreciation	7,340.4	7,071.0
Property, plant and equipment, net	\$27,262.5	\$26,946.6

(1) Plants, pipelines and facilities 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.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table summarizes our depreciation expense and capitalized interest amounts for the periods indicated:

	For the Three Months Ended March 31,	
	2014	2013
Depreciation expense (1)	\$267.9	\$245.4
Capitalized interest (2)	18.5	31.6

(1) Depreciation expense is a component of "Costs and expenses" as presented on our Unaudited Condensed 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 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 first quarter of 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

Property, plant and equipment at March 31, 2014 and December 31, 2013 includes \$36.7 million and \$37.4 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

The following table presents information regarding our asset retirement obligations ("AROs") during the three months ended March 31, 2014:

ARO liability balance, December 31, 2013	\$90.2
Liabilities settled	(0.3)
Revisions in estimated cash flows	0.8
Accretion expense	1.5
ARO liability balance, March 31, 2014	\$92.2

The following table presents our forecast of accretion expense for the periods indicated:

Remainder 2015 2016 2017 2018

of 2014

\$ 4.6 \$6.5 \$6.8 \$7.4 \$7.9

Certain of our unconsolidated affiliates have AROs recorded at March 31, 2014 and December 31, 2013 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our consolidated financial statements.

21

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 7. Investments in Unconsolidated Affiliates

The following table presents our investments in unconsolidated affiliates by business segment at the dates indicated. We account for these investments using the equity method.

	Ownership		
	Interest at	March	December
	March 31,	31,	31,
	2014	2014	2013
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	\$28.9	\$27.6
K/D/S Promix, L.L.C.	50%	45.6	45.4
Baton Rouge Fractionators LLC	32.2%	19.2	19.5
Skelly-Belvieu Pipeline Company, L.L.C.	50%	42.2	40.8
Texas Express Pipeline LLC	35%	344.3	339.9
Texas Express Gathering LLC	45%	37.9	37.8
Front Range Pipeline LLC	33.3%	155.0	134.5
Onshore Natural Gas Pipelines & Services:			
White River Hub, LLC	50%	23.7	24.2
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC	50%	1,166.0	940.7
Eagle Ford Pipeline LLC	50%	237.2	224.5
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36%	40.1	41.7
Cameron Highway Oil Pipeline Company	50%	206.0	207.7
Deepwater Gateway, L.L.C.	50%	83.2	84.5
Neptune Pipeline Company, L.L.C.	25.7%	37.7	38.7
Southeast Keathley Canyon Pipeline Company L.L.C.	50%	161.4	159.2
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	7.3	7.6
Centennial Pipeline LLC ("Centennial")	50%	68.1	60.1
Other	Various	2.6	2.7
Total		\$2,706.4	\$2,437.1

The following table presents our equity in income (loss) of unconsolidated affiliates by business segment for the periods indicated:

	For the Three Months Ended March 31,	
	2014	2013
NGL Pipelines & Services	\$1.4	\$3.9
Onshore Natural Gas Pipelines & Services	0.9	1.0
Onshore Crude Oil Pipelines & Services	42.7	36.6
Offshore Pipelines & Services	11.1	6.4

Edgar Filing: ENTERPRISE PRODUCTS PARTNERS L P - Form 10-Q

Petrochemical & Refined Products Services	0.4	(3.4)
Total	\$56.5	\$44.5

The following table presents our unamortized excess cost amounts by business segment at the dates indicated:

	March 31, 2014	December 31, 2013
NGL Pipelines & Services	\$27.4	\$ 27.7
Onshore Crude Oil Pipelines & Services	17.6	17.8
Offshore Pipelines & Services	9.8	10.0
Petrochemical & Refined Products Services	2.5	2.6
Total	\$57.3	\$ 58.1

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table presents our amortization of excess cost amounts by business segment for the periods indicated:

	For the Three Months Ended March 31, 2014 2013	
NGL Pipelines & Services	\$0.3	\$0.3
Onshore Crude Oil Pipelines & Services	0.2	0.2
Offshore Pipelines & Services	0.2	0.3
Petrochemical & Refined Products Services	0.1	--
Total	\$0.8	\$0.8

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 March 31, 2014.

Note 8. Intangible Assets and Goodwill

The following table summarizes our intangible assets by business segment at the dates indicated:

	March 31, 2014			December 31, 2013		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	\$340.8	\$ (170.3)	\$170.5	\$340.8	\$ (165.7)	\$175.1
Contract-based intangibles	281.3	(175.2)	106.1	281.3	(171.2)	110.1
Segment total	622.1	(345.5)	276.6	622.1	(336.9)	285.2
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,163.6	(288.5)	875.1	1,163.6	(281.2)	882.4
Contract-based intangibles	466.1	(335.0)	131.1	466.1	(330.7)	135.4
Segment total	1,629.7	(623.5)	1,006.2	1,629.7	(611.9)	1,017.8
Onshore Crude Oil Pipelines & Services:						
Customer relationship intangibles	10.7	(6.6)	4.1	10.7	(6.3)	4.4
Contract-based intangibles	0.4	(0.3)	0.1	0.4	(0.3)	0.1
Segment total	11.1	(6.9)	4.2	11.1	(6.6)	4.5
Offshore Pipelines & Services:						
Customer relationship intangibles	195.8	(147.6)	48.2	203.9	(150.0)	53.9
Contract-based intangibles	1.2	(0.4)	0.8	1.2	(0.4)	0.8
Segment total	197.0	(148.0)	49.0	205.1	(150.4)	54.7
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.3	(39.5)	64.8	104.3	(38.2)	66.1

Edgar Filing: ENTERPRISE PRODUCTS PARTNERS L P - Form 10-Q

Contract-based intangibles	39.9	(6.3)	33.6	39.9	(6.0)	33.9
Segment total	144.2	(45.8)	98.4	144.2	(44.2)	100.0
Total all segments	\$2,604.1	\$ (1,169.7)	\$1,434.4	\$2,612.2	\$ (1,150.0)	\$1,462.2

23

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the amortization expense of our intangible assets by business segment for the periods indicated:

	For the Three Months Ended March 31,	
	2014	2013
NGL Pipelines & Services	\$8.6	\$9.6
Onshore Natural Gas Pipelines & Services	11.6	12.4
Onshore Crude Oil Pipelines & Services	0.3	0.3
Offshore Pipelines & Services	2.6	3.0
Petrochemical & Refined Products Services	1.6	1.6
Total	\$24.7	\$26.9

The following table presents our forecast of amortization expense associated with existing intangible assets for the periods indicated:

Remainder of 2014	2015	2016	2017	2018
\$ 69.3	\$85.3	\$80.9	\$85.4	\$88.8

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. The following table presents changes in the carrying amount of goodwill during the three months ended March 31, 2014:

	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, 2013 (1)	\$ 341.2	\$ 296.3	\$ 305.1	\$ 82.1	\$ 1,055.3	\$ 2,080.0
Reclassification to assets held for sale	--	--	--	(0.1)	--	(0.1)
Reclassification of goodwill	520.0	--	--	--	(520.0)	--
Balance at March 31, 2014 (1)	\$ 861.2	\$ 296.3	\$ 305.1	\$ 82.0	\$ 535.3	\$ 2,079.9

(1) The total carrying amount of goodwill at March 31, 2014 and December 31, 2013 is net of \$1.3 million of accumulated impairment charges. No goodwill impairment charges were recorded during the three months ended March 31, 2014.

In January 2014, our Appalachia-to-Texas Express ("ATEX") ethane pipeline commenced operations. In addition to construction of new assets, this project involved repurposing portions of the TE Products Pipeline to accommodate the southbound delivery of ethane produced from the Marcellus and Utica Shales to the U.S. Gulf Coast. The repurposed assets were reclassified from the Petrochemical & Refined Products Services business segment to the NGL Pipelines & Services business segment in January 2014 when the ATEX pipeline commenced operations. Pipeline assets that

continue to be utilized by the TE Products Pipeline in the northbound delivery of refined products and other hydrocarbons from the U.S. Gulf Coast remain in the Petrochemical & Refined Products Services business segment.

In total, the carrying value of the fixed assets at January 1, 2014 that were transferred from the TE Products Pipeline to the ATEX pipeline was \$73.7 million. Based on the relative fair values of the assets involved, we also transferred \$520.0 million of goodwill from the Petrochemical & Refined Products Services business segment to the NGL Pipelines & Services business segment. The relative fair values of the segment assets were determined based on assumptions regarding the future economic prospects of the ATEX pipeline versus the other assets that would remain in the associated reporting unit. These assumptions included: (i) discrete financial forecasts for the pipelines and related businesses contained within the reporting unit, which, in turn, relied on management's estimates of future 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. We believe our assumptions are consistent with those that market participants would utilize in estimating the reporting unit's fair value.

24

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 9. Debt Obligations

The following table presents our consolidated debt obligations (arranged by company and maturity date) at the dates indicated:

	March 31, 2014	December 31, 2013
EPO senior debt obligations:		
Commercial Paper Notes, fixed-rates	\$--	\$475.0
Senior Notes O, 9.75% fixed-rate, due January 2014	--	500.0
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	1,250.0
Senior Notes JJ, 3.90% fixed-rate, due February 2024	850.0	--
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	1,000.0
Senior Notes KK, 5.10% fixed-rate, due February 2045	1,150.0	--
TEPPCO senior debt obligations:		
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	16,850.0	15,825.0
EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066 (1)	550.0	550.0
EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067 (2)	285.8	285.8
EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068 (3)	682.7	682.7
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067 (2)	14.2	14.2
Total principal amount of senior and junior debt obligations	18,382.7	17,357.7

Edgar Filing: ENTERPRISE PRODUCTS PARTNERS L P - Form 10-Q

Other, non-principal amounts	(14.9)	(6.2)
Less current maturities of debt (4)	(900.0)	(1,125.0)
Total long-term debt	\$17,467.8	\$16,226.5

- (1) Fixed rate of 8.375% through August 1, 2016; thereafter, variable rate based on 3-month LIBOR plus 3.7075%.
- (2) Fixed rate of 7.0% through September 1, 2017; thereafter, variable rate based on 3-month LIBOR plus 2.7775%.
- (3) Fixed rate of 7.034% through January 15, 2018; thereafter, the rate will be the greater of 7.034% or a variable rate based on 3-month LIBOR plus 2.68%.
- (4) We expect to refinance the current maturities of our debt obligations at or prior to their maturity.

25

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at March 31, 2014 for the next five years, and in total thereafter:

	Total	Scheduled Maturities of Debt					
		Remainder of					After
		2014	2015	2016	2017	2018	2018
Senior Notes	\$16,850.0	\$650.0	\$1,300.0	\$750.0	\$800.0	\$350.0	\$13,000.0
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Total	\$18,382.7	\$650.0	\$1,300.0	\$750.0	\$800.0	\$350.0	\$14,532.7

Apart from those items discussed below and routine fluctuations in the balance of our revolving credit facility and commercial paper notes, there have been no significant changes in the terms or amounts of our consolidated debt obligations since those reported in our 2013 Form 10-K.

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.

Issuance of Senior Notes in February 2014

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. Proceeds from the issuance of Senior Notes JJ and KK were used to repay debt, including amounts then outstanding under EPO's 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 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 Terminated on May 1, 2014

Effective May 1, 2014, EPO elected to terminate its \$1.0 billion 364-Day Credit Agreement in advance of the facility's scheduled maturity date of June 18, 2014. No borrowings were made under this variable-rate revolving credit facility since its inception.

Letters of Credit

At March 31, 2014, 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 March 31, 2014.

26

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 three months ended March 31, 2014:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
EPO \$3.5 Billion Multi-Year Revolving Credit Facility	1.13% to 1.14%	1.13%

Note 10. Equity and Distributions

Partners' equity reflects the various classes of limited partner interests (i.e., common units, including restricted common units) that we have outstanding. The following table summarizes changes in the number of Enterprise's outstanding units since December 31, 2013:

	Common Units (Unrestricted)	Restricted Common Units	Total Common Units
Number of units outstanding at December 31, 2013	932,074,401	3,610,607	935,685,008
Common units issued in connection with DRIP and EUPP	1,338,465	--	1,338,465
Common units issued in connection with the vesting and exercise of unit options	485,564	--	485,564
Common units issued in connection with the vesting of restricted common unit awards	1,239,862	(1,239,862)	--
Forfeiture of restricted common unit awards	--	(86,650)	(86,650)
Acquisition and cancellation of treasury units in connection with the vesting of equity-based awards	(421,391)	--	(421,391)
Other	7,896	--	7,896
Number of units outstanding at March 31, 2014	934,724,797	2,284,095	937,008,892

We may issue additional equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. We have a universal shelf registration statement (the "2013 Shelf") on file with the SEC. The 2013 Shelf allows Enterprise Products Partners L.P. and EPO (on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. EPO utilized the 2013 Shelf to issue \$2.0 billion of senior notes in February 2014 (see Note 9).

We have a registration statement on file 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. During the three months ended March 31, 2014 and 2013, we did not issue any common units under the "at-the-market" program. After taking into account the aggregate sale price of common units sold under our at-the-market program through March 31, 2014, 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"). We issued 1,307,185 common units under our DRIP during the three months ended March 31, 2014, which generated net proceeds of \$81.0 million.

During the three months ended March 31, 2013, we issued 1,243,360 common units, which generated net proceeds of \$65.7 million. After taking into account the number of common units issued under the DRIP through March 31, 2014, we may issue an additional 17,173,693 common units under this plan.

In January 2014, privately held affiliates of EPCO expressed their willingness to consider purchasing through the DRIP a total of \$100 million of our common units during 2014. During the three months ended March 31, 2014, these EPCO affiliates reinvested \$25.0 million, resulting in the issuance of 403,315 common units under

27

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

our DRIP (this amount being a component of the total common units issued under the DRIP for the three months ended March 31, 2014). In May 2014, these EPCO affiliates reinvested an additional \$25 million through the DRIP.

In addition to the DRIP, we have registration statements on file with the SEC authorizing the issuance of up to 4,000,000 of our common units in connection with an employee unit purchase plan (or "EUPP"). We issued 31,280 common units under our EUPP during the three months ended March 31, 2014, which generated net proceeds of \$2.0 million. During the three months ended March 31, 2013, we issued 31,869 common units, which generated net proceeds of \$1.8 million. After taking into account the number of common units issued under the EUPP through March 31, 2014, we may issue an additional 3,682,164 common units under this plan.

The net cash proceeds we received from the issuance of common units during the three months ended March 31, 2014 were used to temporarily reduce amounts outstanding under EPO's commercial paper program and for general company purposes.

Accumulated Other Comprehensive Loss

The following table presents the components of accumulated other comprehensive income (loss) as reported on our Unaudited Condensed Consolidated Balance Sheets at the dates indicated:

	Gains and Losses on Cash Flow Hedges				Total
	Interest Rate Derivative Instruments	Foreign Currency Translation Adjustment	Other		
Balance, December 31, 2013	\$ (14.7)	\$ (347.2)	\$ 1.7	\$ 1.2	\$ (359.0)
Other comprehensive income before reclassifications	(9.2)	--	--	--	(9.2)
Amounts reclassified from accumulated other comprehensive loss	16.0	7.9	--	--	23.9
Total other comprehensive income	6.8	7.9	--	--	14.7
Balance, March 31, 2014	\$ (7.9)	\$ (339.3)	\$ 1.7	\$ 1.2	\$ (344.3)
	Gains and Losses on Cash Flow Hedges				
	Interest Rate Derivative Instruments	Foreign Currency Translation Adjustment	Other		Total
Balance, December 31, 2012	\$10.1	\$ (383.0)	\$ 1.7	\$ 0.8	\$ (370.4)
Other comprehensive income before reclassifications	(47.6)	6.7	--	--	(40.9)
Amounts reclassified from accumulated other comprehensive income	7.3	5.9	--	--	13.2
Total other comprehensive income	(40.3)	12.6	--	--	(27.7)
Balance, March 31, 2013	\$ (30.2)	\$ (370.4)	\$ 1.7	\$ 0.8	\$ (398.1)

Edgar Filing: ENTERPRISE PRODUCTS PARTNERS L P - Form 10-Q

The following table presents reclassifications out of accumulated other comprehensive income (loss) into net income during the periods indicated:

	Location	For the Three Months Ended March 31,	
		2014	2013
Losses (gains) on cash flow hedges:			
Interest rate derivatives	Interest expense	\$7.9	\$5.9
Commodity derivatives	Revenue	16.9	7.7
Commodity derivatives	Operating costs and expenses	(0.9)	(0.4)
Total		\$23.9	\$13.2

Noncontrolling Interests

Noncontrolling interests as presented on our Unaudited Condensed Consolidated Financial Statements represent third party ownership interests in joint ventures that we consolidate for financial reporting purposes,

28

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

including Tri-States NGL Pipeline L.L.C., Independence Hub LLC, Rio Grande Pipeline Company, Wilprise Pipeline Company LLC and Enterprise EF78 LLC.

Cash Distributions

The following table presents Enterprise's declared quarterly cash distribution rates per common unit with respect to the quarter indicated:

	Distribution Per Common Unit	Record Date	Payment Date
2013:			
1st Quarter	\$ 0.6700	04/30/13	05/07/13
2014:			
1st Quarter	\$ 0.7100	04/30/14	05/07/14

In November 2010, we completed our merger with Enterprise GP Holdings L.P. (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 2014 exclude 22,560,000 Designated Units. Distributions to be paid, if any, during 2015 will exclude 17,690,000 Designated Units.

Note 11. 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.

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. 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.

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.

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

29

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 Three Months Ended March 31,	
	2014	2013
Revenues	\$12,909.9	\$11,383.1
Subtract operating costs and expenses	(11,880.5)	(10,420.4)
Add equity in income of unconsolidated affiliates	56.5	44.5
Add depreciation, amortization and accretion expense amounts not reflected in gross operating margin	301.4	276.8
Add impairment charges not reflected in gross operating margin	8.8	11.0
Subtract net gains attributable to asset sales and insurance recoveries not reflected in gross operating margin	(89.6)	(63.9)
Add non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	23.3	--
Total segment gross operating margin	\$1,329.8	\$1,231.1

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 Three Months Ended March 31,	
	2014	2013
Total segment gross operating margin	\$1,329.8	\$1,231.1
Adjustments to reconcile total segment gross operating margin to operating income:		
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(301.4)	(276.8)
Subtract impairment charges not reflected in gross operating margin	(8.8)	(11.0)
Add net gains attributable to asset sales and insurance recoveries not reflected in gross operating margin (see Note 16)	89.6	63.9
Subtract non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	(23.3)	--
Subtract general and administrative costs not reflected in gross operating margin	(53.2)	(49.5)
Operating income	1,032.7	957.7
Other expense, net	(221.2)	(196.0)
Income before income taxes	\$811.5	\$761.7

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED 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						Adjustments and Eliminations	Consolidated Total
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services			
Revenues from third parties:								
Three months ended March 31, 2014	\$5,173.7	\$1,200.0	\$4,935.4	\$34.7	\$ 1,530.6	\$ --		\$ 12,874.4
Three months ended March 31, 2013	3,950.7	874.2	4,793.2	40.5	1,718.6	--		11,377.2
Revenues from related parties:								
Three months ended March 31, 2014	5.8	4.6	22.9	2.2	--	--		35.5
Three months ended March 31, 2013	0.3	3.5	--	2.1	--	--		5.9
Intersegment and intrasegment revenues:								
Three months ended March 31, 2014	3,861.0	309.4	2,550.7	2.3	437.0	(7,160.4)	--	
Three months ended March 31, 2013	2,709.0	256.2	2,024.7	2.0	422.1	(5,414.0)	--	
Total revenues:								
Three months ended March 31, 2014	9,040.5	1,514.0	7,509.0	39.2	1,967.6	(7,160.4)		12,909.9
Three months ended March 31, 2013	6,660.0	1,133.9	6,817.9	44.6	2,140.7	(5,414.0)		11,383.1
Equity in income (loss) of unconsolidated affiliates:								
Three months ended March 31, 2014	1.4	0.9	42.7	11.1	0.4	--		56.5
Three months ended March 31, 2013	3.9	1.0	36.6	6.4	(3.4)	--		44.5
Gross operating margin:								
Three months ended March 31, 2014	780.0	220.4	159.7	39.3	130.4	--		1,329.8
Three months ended March 31, 2013	592.5	190.8	236.4	40.5	170.9	--		1,231.1
Property, plant and equipment, net: (see Note 6)								

Edgar Filing: ENTERPRISE PRODUCTS PARTNERS L P - Form 10-Q

At March 31, 2014	11,689.7	8,871.8	1,473.4	1,202.3	2,606.2	1,419.1	27,262.5
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
Investments in unconsolidated affiliates: (see Note 7)							
At March 31, 2014	673.1	23.7	1,403.2	528.4	78.0	--	2,706.4
At December 31, 2013	645.5	24.2	1,165.2	531.8	70.4	--	2,437.1
Intangible assets, net: (see Note 8)							
At March 31, 2014	276.6	1,006.2	4.2	49.0	98.4	--	1,434.4
At December 31, 2013	285.2	1,017.8	4.5	54.7	100.0	--	1,462.2
Goodwill: (see Note 8)							
At March 31, 2014	861.2	296.3	305.1	82.0	535.3	--	2,079.9
At December 31, 2013	341.2	296.3	305.1	82.1	1,055.3	--	2,080.0
Segment assets:							
At March 31, 2014	13,500.6	10,198.0	3,185.9	1,861.7	3,317.9	1,419.1	33,483.2
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

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table presents additional information regarding our consolidated revenues and costs and expenses for the periods indicated:

	For the Three Months Ended March 31,	
	2014	2013
NGL Pipelines & Services:		
Sales of NGLs and related products	\$4,795.8	\$3,665.6
Midstream services	383.7	285.4
Total	5,179.5	3,951.0
Onshore Natural Gas Pipelines & Services:		
Sales of natural gas	953.2	639.5
Midstream services	251.4	238.2
Total	1,204.6	877.7
Onshore Crude Oil Pipelines & Services:		
Sales of crude oil	4,873.4	4,742.8
Midstream services	84.9	50.4
Total	4,958.3	4,793.2
Offshore Pipelines & Services:		
Sales of natural gas	0.2	0.1
Sales of crude oil	2.1	2.3
Midstream services	34.6	40.2
Total	36.9	42.6
Petrochemical & Refined Products Services:		
Sales of petrochemicals and refined products	1,356.2	1,547.2
Midstream services	174.4	171.4
Total	1,530.6	1,718.6
Total consolidated revenues	\$12,909.9	\$11,383.1
Consolidated costs and expenses		
Operating costs and expenses:		
Cost of sales	\$11,052.7	\$9,692.5
Other operating costs and expenses (1)	607.2	504.0
Depreciation, amortization and accretion	301.4	276.8
Net gains attributable to asset sales and insurance recoveries	(89.6)	(63.9)
Non-cash asset impairment charges	8.8	11.0
General and administrative costs	53.2	49.5
Total consolidated costs and expenses	\$11,933.7	\$10,469.9

(1) Represents cost of operating our plants, pipelines and other fixed assets, excluding depreciation, amortization and accretion charges.

Quarter-to-quarter 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.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 12. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated:

	For the Three Months Ended March 31,	
	2014	2013
Revenues – related parties:		
Unconsolidated affiliates	\$35.5	\$5.9
Costs and expenses – related parties:		
EPCO and affiliates	\$235.7	\$212.7
Unconsolidated affiliates	56.6	31.3
Total	\$292.3	\$244.0

The following table summarizes our related party accounts receivable and accounts payable balances at the dates indicated:

	March 31, 2014	December 31, 2013
Accounts receivable - related parties:		
Unconsolidated affiliates	\$5.5	\$6.8
Accounts payable - related parties:		
EPCO and affiliates	\$58.3	\$116.3
Unconsolidated affiliates	32.7	34.2
Total	\$91.0	\$150.5

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 March 31, 2014, 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
341,283,694	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 three months ended March 31, 2014 and 2013, we paid EPCO and its privately held affiliates cash distributions totaling \$214.2 million and \$197.1 million, respectively.

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 10 for information regarding these reinvestments made during 2014.

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.

33

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 Three Months Ended March 31, 2014 2013	
Operating costs and expenses	\$203.7	\$181.1
General and administrative expenses	32.0	31.6
Total costs and expenses	\$235.7	\$212.7

Note 13. Earnings Per Unit

The following table presents our calculation of basic and diluted earnings per unit for the periods indicated:

	For the Three Months Ended March 31, 2014		2013
BASIC EARNINGS PER UNIT			
Net income attributable to limited partners	\$	798.8	\$ 753.5
Undistributed earnings allocated and cash payments on phantom unit awards (1)		(1.5)	--
Net income available to common unitholders	\$	797.3	\$ 753.5
Basic weighted-average number of common units outstanding		914.0	881.6
Basic earnings per unit	\$	0.87	\$ 0.85
DILUTED EARNINGS PER UNIT			
Net income attributable to limited partners	\$	798.8	\$ 753.5
Diluted weighted-average number of units outstanding:			
Distribution-bearing common units		914.0	881.6
Designated Units		22.6	23.7
Class B units (2)		--	4.5

Phantom units (1)	0.8	--
Incremental option units	0.6	1.2
Total	938.0	911.0
Diluted earnings per unit	\$ 0.85	\$ 0.83

(1) Each phantom unit award includes a DER, which entitles the recipient to receive cash payments equal to the product of the number of phantom unit awards and the cash distribution per unit paid to Enterprise's common unitholders. Cash payments made in connection with DERs are nonforfeitable. As a result, the phantom units are considered participating securities for purposes of computing basic earnings per unit. Phantom unit awards were first issued in February 2014.

(2) The Class B units automatically converted into an equal number of distribution-bearing common units in August 2013.

Note 14. 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

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 March 31, 2014 and December 31, 2013, our accruals for litigation contingencies were \$7.0 million and \$3.7 million, respectively, and were recorded in our Unaudited Condensed 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.

ETP Matter. In connection with a proposed pipeline project, we and Energy Transfer Partners, L.P. ("ETP") signed a non-binding letter of intent in April 2011 that disclaimed any partnership or joint venture related to such project absent executed definitive documents and board approvals of the respective companies. Definitive agreements were never executed and board approval was never obtained for the potential pipeline project. In August 2011, the proposed pipeline project was cancelled due to a lack of customer support.

In September 2011, ETP filed suit against us and a third party in connection with the cancelled project alleging, among other things, that we and ETP had formed a "partnership." The case was tried in the District Court of Dallas County, Texas, 298th Judicial District. While we firmly believe, and argued during our defense, that no agreement was ever executed forming a legal joint venture or partnership between the parties, the jury found that the actions of the two companies, nevertheless, constituted a legal partnership. As a result, the jury found that ETP was wrongfully excluded from a subsequent pipeline project involving a third party, and awarded ETP \$319.4 million in actual damages on March 4, 2014. On April 21, 2014, ETP filed a motion with the court for entry of judgment against us in an aggregate amount of approximately \$914.7 million plus prejudgment interest, which aggregate amount includes (i) the amount of actual damages awarded by the jury and (ii) an additional \$595.3 million in disgorgement for the alleged benefit we received due to a breach of fiduciary duties by us against ETP. A judgment has not yet been entered in this case.

We do not believe that the verdict or the plaintiff's motion for judgment is supported by the evidence or the law and intend to vigorously oppose any judgment based on such verdict or the plaintiff's motion for judgment. As of March 31, 2014, we have not recorded a provision for this matter as management believes payment of damages in this case is not probable.

Contractual Obligations

Scheduled Maturities of Debt. With the exception of routine fluctuations in the balance of our revolving credit facility and commercial paper notes, the issuance of senior notes in February 2014 and the scheduled repayment of maturing debt obligations, there have been no significant changes in our consolidated debt obligations since those reported in

our 2013 Form 10-K. See Note 9 for additional information regarding our consolidated debt obligations.

Operating Lease Obligations. Consolidated lease and rental expense was \$23.2 million and \$22.0 million during the three months ended March 31, 2014 and 2013, respectively. There have been no material changes in our operating lease commitments since those reported in our 2013 Form 10-K.

Purchase Obligations. There have been no material changes in our consolidated purchase obligations since those reported in our 2013 Form 10-K.

35

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 15. 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.

We expect to forego windstorm coverage for our Gulf of Mexico offshore assets during the upcoming 2014 Atlantic hurricane season, which extends from June 1 through November 30. The combination of increasingly high deductibles and proposed 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, 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.

West Storage Claims

In February 2011, we experienced an NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. We collected \$95.0 million and \$8.8 million of nonrefundable cash insurance proceeds attributable to this incident during the three months ended March 31, 2014 and 2013, respectively. The payments we received during the first quarter of 2014 represent the final installments on this property damage claim.

Operating income for the three months ended March 31, 2014 and 2013 includes \$95.0 million and \$8.8 million, respectively, of gains related to these insurance recoveries. To the extent that we received nonrefundable cash insurance proceeds related to this incident, we recorded gains equal to such proceeds as a reduction in operating costs and expenses.

Note 16. Supplemental Cash Flow Information

The following table presents the net effect of changes in our operating accounts for the periods indicated:

	For the Three Months Ended March 31,	
	2014	2013
Decrease (increase) in:		
Accounts receivable – trade	\$483.3	\$(163.5)
Accounts receivable – related parties	1.3	(0.2)
Inventories	65.7	84.1
Prepaid and other current assets	5.6	8.5
Other assets	23.5	2.1
Increase (decrease) in:		
Accounts payable – trade	106.9	(32.8)
Accounts payable – related parties	(59.5)	(34.0)
Accrued product payables	(149.1)	261.7
Accrued interest	(132.2)	(115.2)

Other current liabilities	(9.6)	(0.2)
Other liabilities	6.6	(18.5)
Net effect of changes in operating accounts	\$342.5	\$(8.0)

We incurred liabilities for construction in progress that had not been paid at March 31, 2014 and December 31, 2013 of \$182.4 million and \$205.3 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Unaudited Condensed 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 Unaudited Condensed Statements of Consolidated Cash Flows.

36

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table presents our cash proceeds from asset sales and insurance recoveries for the periods indicated:

	For the Three Months Ended March 31,	
	2014	2013
Sale of Stratton Ridge-to-Mont Belvieu segment of Seminole Pipeline (see Note 6)	\$--	\$86.9
Sale of chemical trucking assets	--	29.5
Insurance recoveries attributable to West Storage claims (see Note 15)	95.0	8.8
Other cash proceeds	1.3	5.3
Total	\$96.3	\$130.5

The following table presents net gains (losses) attributable to asset sales and insurance recoveries for the periods indicated:

	For the Three Months Ended March 31,	
	2014	2013
Sale of Stratton Ridge-to-Mont Belvieu segment of Seminole Pipeline (see Note 6)	\$--	\$52.5
Sale of chemical trucking assets	--	(0.5)
Net gains (losses) attributable to other asset sales	(5.4)	3.1
Gains attributable to West Storage insurance recoveries (see Note 15)	95.0	8.8
Total	\$89.6	\$63.9

Note 17. 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 9 for additional information regarding our consolidated debt obligations.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.

Unaudited Condensed Consolidating Balance Sheet

March 31, 2014

	EPO and Subsidiaries				Enterprise Products		
	Subsidiary	Other	EPO and	Consolidated	Partners	Eliminations	Consolidated
	Issuer	Subsidiaries	Subsidiaries	EPO and	L.P.	and	Total
	(EPO)	(Non-	and	Subsidiaries	(Guarantor)	Adjustments	
		guarantor)	Adjustments				
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash							
	\$993.7	\$45.3	\$(7.0)	\$1,032.0	\$--	\$(0.3)	\$1,031.7
Accounts receivable – trade, net	1,410.2	3,581.4	(3.5)	4,988.1	--	--	4,988.1
Accounts receivable – related parties	330.9	1,472.0	(1,748.6)	54.3	--	(48.8)	5.5
Inventories	612.5	366.5	(1.1)	977.9	--	--	977.9
Prepaid and other current assets	119.2	213.8	(3.4)	329.6	0.4	--	330.0
Total current assets	3,466.5	5,679.0	(1,763.6)	7,381.9	0.4	(49.1)	7,333.2
Property, plant and equipment, net							
	2,045.3	25,215.7	1.5	27,262.5	--	--	27,262.5
Investments in unconsolidated affiliates							
	31,585.4	3,233.9	(32,112.9)	2,706.4	15,487.5	(15,487.5)	2,706.4
Intangible assets, net	76.6	1,373.3	(15.5)	1,434.4	--	--	1,434.4
Goodwill	458.8	1,621.1	--	2,079.9	--	--	2,079.9
Other assets	134.0	41.5	(1.5)	174.0	0.1	--	174.1
Total assets	\$37,766.6	\$37,164.5	\$(33,892.0)	\$41,039.1	\$15,488.0	\$(15,536.6)	\$40,990.5
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt							
	\$900.0	\$--	\$--	\$900.0	\$--	\$--	\$900.0
Accounts payable – trade	235.8	521.7	(7.0)	750.5	0.3	(0.3)	750.5
Accounts payable – related parties	1,609.7	245.6	(1,764.3)	91.0	48.8	(48.8)	91.0
Accrued product payables	1,856.0	3,561.1	(4.5)	5,412.6	--	--	5,412.6
Accrued interest	171.7	0.4	--	172.1	--	--	172.1
Other current liabilities	61.9	239.0	(3.4)	297.5	--	(1.7)	295.8
Total current liabilities	4,835.1	4,567.8	(1,779.2)	7,623.7	49.1	(50.8)	7,622.0
Long-term debt	17,452.9	14.9	--	17,467.8	--	--	17,467.8

Edgar Filing: ENTERPRISE PRODUCTS PARTNERS L P - Form 10-Q

Deferred tax liabilities	3.9	54.9	(1.6)	57.2	--	3.4	60.6
Other long-term liabilities	10.1	168.5	(0.5)	178.1	--	--	178.1
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	15,464.6	32,288.0	(32,289.7)	15,462.9	15,438.9	(15,462.9)	15,438.9
Noncontrolling interests	--	70.4	179.0	249.4	--	(26.3)	223.1
Total equity	15,464.6	32,358.4	(32,110.7)	15,712.3	15,438.9	(15,489.2)	15,662.0
Total liabilities and equity	\$37,766.6	\$37,164.5	\$(33,892.0)	\$41,039.1	\$15,488.0	\$(15,536.6)	\$40,990.5

38

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.

Unaudited Condensed Consolidating Balance Sheet

December 31, 2013

	EPO and Subsidiaries		EPO and		Enterprise		
	Subsidiary	Other	Subsidiaries	Consolidated	Products	Eliminations	Consolidated
	Issuer	(Non-	and	EPO and	L.P.	and	Total
	(EPO)	guarantor)	Adjustments	Subsidiaries	(Guarantor)	Adjustments	
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	16,211.6	14.9	--	16,226.5	--	--	16,226.5

Edgar Filing: ENTERPRISE PRODUCTS PARTNERS L P - Form 10-Q

Deferred tax liabilities	4.3	55.0	(1.4)	57.9	--	2.9	60.8
Other long-term liabilities	11.8	160.5	--	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

39

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.

Unaudited Condensed Consolidating Statement of Operations

Three Months Ended March 31, 2014

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
Revenues	\$9,490.9	\$ 8,110.6	\$ (4,691.6)	\$ 12,909.9	\$ --	\$ --	\$ 12,909.9
Costs and expenses:							
Operating costs and expenses	9,167.8	7,404.5	(4,691.8)	11,880.5	--	--	11,880.5
General and administrative costs	7.3	45.7	--	53.0	0.2	--	53.2
Total costs and expenses	9,175.1	7,450.2	(4,691.8)	11,933.5	0.2	--	11,933.7
Equity in income of unconsolidated affiliates	706.8	85.8	(736.1)	56.5	799.0	(799.0)	56.5
Operating income	1,022.6	746.2	(735.9)	1,032.9	798.8	(799.0)	1,032.7
Other income (expense):							
Interest expense	(220.8)	(0.1)	--	(220.9)	--	--	(220.9)
Other, net	0.2	(0.5)	--	(0.3)	--	--	(0.3)
Total other expense, net	(220.6)	(0.6)	--	(221.2)	--	--	(221.2)
Income before income taxes	802.0	745.6	(735.9)	811.7	798.8	(799.0)	811.5
Provision for income taxes	(4.2)	(0.3)	--	(4.5)	--	(0.3)	(4.8)
Net income	797.8	745.3	(735.9)	807.2	798.8	(799.3)	806.7
Net income attributable to noncontrolling interests	--	--	(9.1)	(9.1)	--	1.2	(7.9)
Net income attributable to entity	\$797.8	\$ 745.3	\$ (745.0)	\$ 798.1	\$ 798.8	\$ (798.1)	\$ 798.8

Enterprise Products Partners L.P.

Unaudited Condensed Consolidating Statement of Operations

Three Months Ended March 31, 2013

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
Revenues	\$7,355.5	\$ 7,440.4	\$ (3,412.8)	\$ 11,383.1	\$ --	\$ --	\$ 11,383.1
Costs and expenses:							
Operating costs and expenses	7,143.9	6,689.2	(3,412.7)	10,420.4	--	--	10,420.4
	4.7	44.6	--	49.3	0.2	--	49.5

Edgar Filing: ENTERPRISE PRODUCTS PARTNERS L P - Form 10-Q

General and administrative costs

Total costs and expenses	7,148.6	6,733.8	(3,412.7)	10,469.7	0.2	--	10,469.9
Equity in income of unconsolidated affiliates	746.7	51.2	(753.4)	44.5	753.7	(753.7)	44.5
Operating income	953.6	757.8	(753.5)	957.9	753.5	(753.7)	957.7
Other income (expense):							
Interest expense	(195.3)	(0.6)	--	(195.9)	--	--	(195.9)
Other, net	0.1	(0.2)	--	(0.1)	--	--	(0.1)
Total other expense, net	(195.2)	(0.8)	--	(196.0)	--	--	(196.0)
Income before income taxes	758.4	757.0	(753.5)	761.9	753.5	(753.7)	761.7
Provision for income taxes	(5.1)	(1.0)	--	(6.1)	--	(0.3)	(6.4)
Net income	753.3	756.0	(753.5)	755.8	753.5	(754.0)	755.3
Net income attributable to noncontrolling interests	--	(0.5)	(2.0)	(2.5)	--	0.7	(1.8)
Net income attributable to entity	\$753.3	\$755.5	\$(755.5)	\$753.3	\$753.5	\$(753.3)	\$753.5

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.

Unaudited Condensed Consolidating Statement of Comprehensive Income

Three Months Ended March 31, 2014

	EPO and Subsidiaries						
	Other Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries and Adjustments	Eliminations EPO and Subsidiaries	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments
Comprehensive income	\$808.0	\$ 749.8	\$ (735.9)	\$ 821.9	\$ 813.5	\$ (814.0)	\$ 821.4
Comprehensive income attributable to noncontrolling interests	--	--	(9.1)	(9.1)	--	1.2	(7.9)
Comprehensive income attributable to entity	\$808.0	\$ 749.8	\$ (745.0)	\$ 812.8	\$ 813.5	\$ (812.8)	\$ 813.5

Enterprise Products Partners L.P.

Unaudited Condensed Consolidating Statement of Comprehensive Income

Three Months Ended March 31, 2013

	EPO and Subsidiaries						
	Other Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries and Adjustments	Eliminations EPO and Subsidiaries	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments
Comprehensive income	\$753.0	\$ 728.4	\$ (753.4)	\$ 728.0	\$ 725.8	\$ (726.2)	\$ 727.6
Comprehensive income attributable to noncontrolling interests	--	(0.5)	(2.0)	(2.5)	--	0.7	(1.8)
Comprehensive income attributable to entity	\$753.0	\$ 727.9	\$ (755.4)	\$ 725.5	\$ 725.8	\$ (725.5)	\$ 725.8

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.

Unaudited Condensed Consolidating Statement of Cash Flows

Three Months Ended March 31, 2014

	EPO and Subsidiaries		EPO and	Enterprise			
	Subsidiary	Other	Subsidiaries	Consolidated	Products	Eliminations	Consolidated
	Issuer	Subsidiaries	and	EPO and	Partners	and	Total
	(EPO)	(Non-	Adjustments	Subsidiaries	L.P.	Adjustments	
		guarantor)			(Guarantor)		
Operating activities:							
Net income	\$797.8	\$745.3	\$(735.9)	\$807.2	\$798.8	\$(799.3)	\$806.7
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	35.4	284.7	(0.2)	319.9	--	--	319.9
Equity in income of unconsolidated affiliates	(706.8)	(85.8)	736.1	(56.5)	(799.0)	799.0	(56.5)
Distributions received from unconsolidated affiliates	1,039.3	68.8	(1,036.4)	71.7	685.2	(685.2)	71.7
Net effect of changes in operating accounts and other operating activities	(4.5)	250.1	14.0	259.6	2.7	--	262.3
Net cash flows provided by operating activities	1,161.2	1,263.1	(1,022.4)	1,401.9	687.7	(685.5)	1,404.1
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(85.3)	(610.1)	--	(695.4)	--	--	(695.4)
Proceeds from asset sales and insurance recoveries	0.1	96.2	--	96.3	--	--	96.3
Other investing activities	(555.3)	(255.2)	548.1	(262.4)	(80.9)	80.9	(262.4)
Cash used in investing activities	(640.5)	(769.1)	548.1	(861.5)	(80.9)	80.9	(861.5)
Financing activities:							
Borrowings under debt agreements	4,181.5	--	--	4,181.5	--	--	4,181.5
Repayments of debt	(3,160.0)	--	--	(3,160.0)	--	--	(3,160.0)
Cash distributions paid to partners	(685.2)	(1,044.3)	1,044.3	(685.2)	(639.2)	685.2	(639.2)
Cash distributions paid to noncontrolling interests	--	--	(8.0)	(8.0)	--	--	(8.0)
Net cash proceeds from issuance of common units	--	--	--	--	83.0	--	83.0

Edgar Filing: ENTERPRISE PRODUCTS PARTNERS L P - Form 10-Q

Cash contributions from owners	80.9	546.1	(546.1)	80.9	--	(80.9)	--
Other financing activities	(15.9)	--	(1.9)	(17.8)	(50.6)	--	(68.4)
Cash provided by (used in) financing activities	401.3	(498.2)	488.3	391.4	(606.8)	604.3	388.9
Net change in cash and cash equivalents	922.0	(4.2)	14.0	931.8	--	(0.3)	931.5
Cash and cash equivalents, January 1	28.4	49.5	(21.0)	56.9	--	--	56.9
Cash and cash equivalents, March 31	\$950.4	\$45.3	\$(7.0)	\$988.7	\$--	\$(0.3)	\$988.4

42

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.

Unaudited Condensed Consolidating Statement of Cash Flows

Three Months Ended March 31, 2013

	EPO and Subsidiaries		EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)					
Operating activities:							
Net income	\$753.3	\$756.0	\$(753.5)	\$755.8	\$753.5	\$(754.0)	\$755.3
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	33.8	258.2	--	292.0	--	--	292.0
Equity in income of unconsolidated affiliates	(746.7)	(51.2)	753.4	(44.5)	(753.7)	753.7	(44.5)
Distributions received from unconsolidated affiliates	1,173.7	50.3	(1,172.7)	51.3	577.6	(577.6)	51.3
Net effect of changes in operating accounts and other operating activities	(76.8)	16.2	6.5	(54.1)	23.2	(23.3)	(54.2)
Net cash flows provided by operating activities	1,137.3	1,029.5	(1,166.3)	1,000.5	600.6	(601.2)	999.9
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(62.1)	(560.8)	--	(622.9)	--	--	(622.9)
Proceeds from asset sales and insurance recoveries	--	130.5	--	130.5	--	--	130.5
Other investing activities	(958.6)	(203.9)	807.7	(354.8)	(552.5)	552.5	(354.8)
Cash used in investing activities	(1,020.7)	(634.2)	807.7	(847.2)	(552.5)	552.5	(847.2)
Financing activities:							
Borrowings under debt agreements	6,174.6	--	--	6,174.6	--	--	6,174.6
Repayments of debt	(4,809.2)	(17.4)	--	(4,826.6)	--	--	(4,826.6)
Cash distributions paid to partners	(601.2)	(1,175.1)	1,175.1	(601.2)	(577.6)	601.2	(577.6)
Cash distributions paid to noncontrolling interests	--	--	(2.4)	(2.4)	--	--	(2.4)
Net cash proceeds from issuance of common units	--	--	--	--	554.1	--	554.1

Edgar Filing: ENTERPRISE PRODUCTS PARTNERS L P - Form 10-Q

Cash contributions from owners	552.5	807.7	(807.7)	552.5	--	(552.5)	--
Other financing activities	(186.0)	--	--	(186.0)	(24.6)	--	(210.6)
Cash provided by (used in) financing activities	1,130.7	(384.8)	365.0	1,110.9	(48.1)	48.7	1,111.5
Net change in cash and cash equivalents	1,247.3	10.5	6.4	1,264.2	--	--	1,264.2
Cash and cash equivalents, January 1	--	28.0	(12.1)	15.9	0.2	--	16.1
Cash and cash equivalents, March 31	\$1,247.3	\$38.5	\$(5.7)	\$1,280.1	\$0.2	\$--	\$1,280.3

Table of Contents

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

For the Three Months Ended March 31, 2014 and 2013.

The following information should be read in conjunction with our Unaudited Condensed Consolidated Financial Statements and accompanying Notes included in this quarterly report on Form 10-Q and the Audited Consolidated Financial Statements and related Notes, together with our discussion and analysis of financial position and results of operations, included in our annual report on Form 10-K for the year ended December 31, 2013, as filed on March 3, 2014 (the "2013 Form 10-K"). Our financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States ("U.S.").

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 privately held 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; and (iii) Richard H. Bachmann. 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 privately held 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, privately held affiliates of EPCO owned approximately 36.4% of our limited partner interests at March 31, 2014.

As generally used in the energy industry and in this quarterly 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 quarterly report on Form 10-Q 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," "would," "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 "Risk Factors" within Part I, Item 1A included in our 2013 Form 10-K. 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 quarterly report speak

44

Table of Contents

only as of the filing 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 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 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Significant Recent Developments

The following information highlights significant commercial and operational developments since January 1, 2014 through the date of this filing (May 9, 2014). For information regarding recent offerings of our equity and debt securities, see "Liquidity and Capital Resources" within this Part I, Item 2.

Plans to Construct Ethane Export Facility on Texas Gulf Coast

In April 2014, we announced plans to construct a fully refrigerated ethane export facility on the Gulf Coast. We have executed long-term contracts to support development of the facility, which is expected to have an aggregate loading rate of approximately 10,000 barrels per hour, or up to 240 MBPD. We expect the ethane export facility to begin operations in the third quarter of 2016.

This facility will provide new markets for domestically-produced ethane, and will assist U.S. producers in increasing their associated production of natural gas and crude oil. We estimate that U.S. ethane production capacity currently exceeds U.S. demand by 300 MBPD and could exceed demand by up to 700 MBPD by 2020, after considering the estimated incremental demand from new ethylene facilities that have been announced.

The ethane export facility will be integrated with our Mont Belvieu complex, which includes over 650 MBPD of NGL fractionation capacity and 100 MMBbls of NGL storage capacity. Our Mont Belvieu complex

45

Table of Contents

receives NGL supplies from several major producing basins across the U.S., including the Marcellus and Utica Shales via our recently completed Appalachia-to-Texas Express ("ATEX") ethane pipeline. We believe that our integrated NGL system offers supply assurance and diversification for the ethane export facility.

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 and Anadarko Petroleum Corporation. We operate the Front Range Pipeline and own a one-third member interest in Front Range Pipeline LLC.

ATEX Pipeline Begins Operations

Our ATEX pipeline commenced operations in January 2014. The ATEX pipeline transports ethane southbound 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 pipeline consist of segments that were formerly used in refined products transportation service by our TE Products Pipeline. Initial throughput capacity for the ATEX pipeline is 125 MBPD, which could be expanded to approximately 265 MBPD with certain system modifications.

ATEX 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 and scheduled to begin service in 2015), 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 in Texas and Louisiana. Also, ethane volumes delivered to Mont Belvieu via ATEX may support our recently announced ethane export facility.

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., 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.

46

Table of Contents

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.

Results of Operations

Summarized Consolidated Income Statement Data

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

	For the Three Months Ended March 31,	
	2014	2013
Revenues	\$12,909.9	\$11,383.1
Costs and expenses:		
Operating costs and expenses:		
Cost of sales	11,052.7	9,692.5
Other operating costs and expenses	607.2	504.0
Depreciation, amortization and accretion expenses	301.4	276.8
Net gains attributable to asset sales and insurance recoveries	(89.6)	(63.9)
Non-cash asset impairment charges	8.8	11.0
Total operating costs and expenses	11,880.5	10,420.4
General and administrative costs	53.2	49.5
Total costs and expenses	11,933.7	10,469.9
Equity in income of unconsolidated affiliates	56.5	44.5
Operating income	1,032.7	957.7
Interest expense	(220.9)	(195.9)
Other, net	(0.3)	(0.1)
Provision for income taxes	(4.8)	(6.4)
Net income	806.7	755.3
Net income attributable to noncontrolling interests	(7.9)	(1.8)
Net income attributable to limited partners	\$798.8	\$753.5

Table of Contents

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

	For the Three Months Ended March 31,	
	2014	2013
NGL Pipelines & Services:		
Sales of NGLs and related products	\$4,795.8	\$3,665.6
Midstream services	383.7	285.4
Total	5,179.5	3,951.0
Onshore Natural Gas Pipelines & Services:		
Sales of natural gas	953.2	639.5
Midstream services	251.4	238.2
Total	1,204.6	877.7
Onshore Crude Oil Pipelines & Services:		
Sales of crude oil	4,873.4	4,742.8
Midstream services	84.9	50.4
Total	4,958.3	4,793.2
Offshore Pipelines & Services:		
Sales of natural gas	0.2	0.1
Sales of crude oil	2.1	2.3
Midstream services	34.6	40.2
Total	36.9	42.6
Petrochemical & Refined Products Services:		
Sales of petrochemicals and refined products	1,356.2	1,547.2
Midstream services	174.4	171.4
Total	1,530.6	1,718.6
Total consolidated revenues	\$12,909.9	\$11,383.1

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		Normal			Natural	Polymer	Refinery	WTI	LLS
	Gas, \$/MMBtu (1)	Ethane, \$/gallon (2)	Propane, \$/gallon (2)	Butane, \$/gallon (2)	Isobutane, \$/gallon (2)	Gasoline, \$/gallon (2)	Propylene, \$/pound (3)	Propylene, \$/pound (3)	Crude Oil, \$/barrel (4)	Crude Oil, \$/barrel (4)
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
2014 by quarter:										

Edgar Filing: ENTERPRISE PRODUCTS PARTNERS L P - Form 10-Q

1st Quarter	\$ 4.95	\$ 0.34	\$ 1.30	\$ 1.39	\$ 1.42	\$ 2.12	\$ 0.73	\$ 0.61	\$98.68	\$104.43
-------------	---------	---------	---------	---------	---------	---------	---------	---------	---------	----------

(1) Natural gas prices are based on Henry-Hub Inside FERC commercial index prices as reported by Platts, which is a division of The McGraw-Hill Companies.

(2) NGL prices for ethane, propane, normal butane, isobutane and natural gasoline are based on Mont Belvieu Non-TET commercial index prices as reported by Oil Price Information Service.

(3) Polymer-grade propylene prices represent average contract pricing for such product as reported by Chemical Market Associates, Inc. ("CMAI"). Refinery grade propylene prices represent weighted-average spot prices for such product as reported by CMAI.

(4) Crude oil prices are based on commercial index prices for West Texas Intermediate ("WTI") as measured on the New York Mercantile Exchange ("NYMEX") and for Louisiana Light Sweet ("LLS") as reported by Platts.

48

Table of Contents

Quarter-to-quarter 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 quarter-to-quarter changes in key commodity prices affecting our results of operations:

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 \$1.13 per gallon during the first quarter of 2014 versus \$1.02 per gallon during the first quarter of 2013 – an 11% quarter-to-quarter increase. Ethane accounts for the largest volume of NGLs extracted from the natural gas stream. The price of ethane averaged \$0.34 per gallon during the first quarter of 2014 compared to \$0.26 per gallon during the first quarter of 2013. 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.

The market price of natural gas (as measured at the Henry Hub in Louisiana) averaged \$4.95 per MMBtu during the first quarter of 2014 versus \$3.34 per MMBtu during the first quarter of 2013 – a 48% quarter-to-quarter increase.

The increase in price 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 \$98.68 per barrel during the first quarter of 2014 compared to \$94.37 per barrel during the first quarter of 2013 – an 5% quarter-to-quarter increase. As a result of our recent crude oil pipeline infrastructure improvements, we have greater access to U.S. Gulf Coast refiners. Typically, these refining customers purchase crude oil based on LLS prices, which are significantly higher than WTI prices. Although down quarter-to-quarter, LLS prices averaged \$104.43 per barrel during the first quarter of 2014 compared to \$113.93 per barrel during the first quarter of 2013.

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 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly 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.

Revenues for the first quarter of 2014 increased \$1.53 billion when compared to the first quarter of 2013. Revenues from the marketing of NGLs increased \$1.13 billion quarter-to-quarter primarily due to higher sales prices, which accounted for a \$909.0 million increase, and higher sales volumes, which accounted for an additional \$221.2 million increase. Revenues from the marketing of natural gas increased a net \$313.8 million quarter-to-quarter primarily due to higher sales prices, which accounted for a \$360.1 million increase, partially offset by lower sales volumes, which accounted for a \$46.3 million decrease. Revenues from the marketing of crude oil increased a net \$130.4 million quarter-to-quarter primarily due to higher sales volumes, which accounted for a \$1.21 billion increase, partially offset by lower sales prices, which accounted for a \$1.08 billion decrease. Revenues from the marketing of octane additives

and high purity isobutylene ("HPIB") decreased a combined \$154.1 million quarter-to-quarter primarily due to lower sales volumes, which accounted for a \$140.9 million decrease, and sales prices, which accounted for an additional \$13.2 million decrease. Revenues from the marketing of petrochemical products

49

Table of Contents

decreased \$63.8 million quarter-to-quarter primarily due to lower sales volumes. Revenues from midstream asset services increased \$143.4 million quarter-to-quarter primarily due to contributions from recently completed assets such as the ATEX Pipeline as well as assets that have started operations in the Eagle Ford Shale and at our Mont Belvieu complex.

Total operating costs and expenses for the first quarter of 2014 increased \$1.46 billion when compared to the first quarter of 2013 primarily due to a \$1.36 billion increase in cost of sales. The cost of sales associated with our marketing of NGLs increased \$1.0 billion quarter-to-quarter primarily due to higher purchase prices, which accounted for an \$825.4 million increase, and sales volumes, which accounted for an additional \$177.3 million increase. Cost of sales associated with the marketing of natural gas increased a net \$257.3 million quarter-to-quarter primarily due to higher purchase prices, which accounted for a \$301.2 million increase, partially offset by lower sales volumes, which accounted for a \$43.9 million decrease. Cost of sales associated with our marketing of crude oil increased a net \$158.0 million quarter-to-quarter primarily due to higher sales volumes, which accounted for a \$1.14 billion increase, partially offset by lower purchase costs, which accounted for a \$977.7 million decrease. Cost of sales associated with our marketing of octane additives and HPIB decreased \$80.8 million quarter-to-quarter primarily due to lower sales volumes, which accounted for a \$44.9 million decrease, and lower purchase costs, which accounted for an additional \$35.9 million decrease. Cost of sales associated with the marketing of petrochemical products decreased a net \$25.8 million quarter-to-quarter primarily due to lower sales volumes, which accounted for a \$76.8 million decrease, partially offset by higher purchase costs, which accounted for a \$51.0 million increase.

Other operating costs and expenses increased \$103.2 million quarter-to-quarter primarily due to (i) higher overall costs for maintenance and utilities, which accounted for \$50.2 million of the increase, (ii) a negative variance of \$26.3 million quarter-to-quarter attributable to \$8.3 million of volumetric measurement losses in the first quarter of 2014 compared to \$18.0 million of volumetric measurement gains in the first quarter of 2013, and (iii) a \$16.6 million benefit recognized in the first quarter of 2013 attributable to reductions in a provision for pipeline capacity obligations associated with our refined products terminals. Depreciation, amortization and accretion expenses in operating costs and expenses increased \$24.6 million for the first quarter of 2014 when compared to the first quarter of 2013 primarily due to recently constructed assets being placed into service.

We recorded net gains within operating costs and expenses of \$89.6 million attributable to asset sales and insurance recoveries in the first quarter of 2014 compared to \$63.9 million in the first quarter of 2013. We recognized \$95.0 million of gains attributable to the receipt of nonrefundable cash insurance proceeds related to our West Storage claims in the first quarter of 2014 compared to \$8.8 million of such gains in the first quarter of 2013. 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. 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.

General and administrative costs for the first quarter of 2014 increased \$3.7 million when compared to the first quarter of 2013 primarily due to costs we incurred during the first quarter of 2014 related to the settlement of litigation associated with Enterprise GP Holdings L.P.

Equity income from our unconsolidated affiliates for the first quarter of 2014 increased \$12.0 million when compared to the first quarter of 2013 primarily due to higher equity earnings from our investments in crude oil pipeline joint ventures.

Table of Contents

Interest expense for the first quarter of 2014 increased \$25.0 million when compared to the first quarter of 2013. The following table presents the components of our consolidated interest expense for the periods indicated (dollars in millions):

	For the Three Months Ended March 31,	
	2014	2013
Interest charged on debt principal outstanding	\$232.9	\$223.2
Impact of interest rate hedging program, including related amortization	1.4	(1.0)
Interest costs capitalized in connection with construction projects (1)	(18.5)	(31.6)
Other (2)	5.1	5.3
Interest expense	\$220.9	\$195.9

(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 quarter-to-quarter 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 \$9.7 million quarter-to-quarter generally due to increased debt principal amounts outstanding during the first quarter of 2014, which accounted for a \$16.8 million increase, partially offset by the effect of lower overall interest rates in the first quarter of 2014, which accounted for a \$7.1 million decrease. Our weighted-average debt principal balance for the first quarter of 2014 was \$17.76 billion compared to \$16.81 billion for the first quarter of 2013. 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 Part I, Item 2.

Provision for income taxes for the first quarter of 2014 decreased \$1.6 million when compared to the first quarter of 2013 primarily due to changes in our accruals for state tax obligations under the Revised Texas Franchise Tax (or "Texas Margin Tax").

Business Segment Highlights

Total segment gross operating margin was \$1.33 billion for the first quarter of 2014 compared to \$1.23 billion for the first quarter of 2013.

The following information highlights significant changes in our quarter-to-quarter 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.

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 Measures" within this Part

I, Item 2.

51

Table of Contents

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

	For the Three Months Ended March 31,	
	2014	2013
Segment gross operating margin:		
Natural gas processing and related NGL marketing activities	\$349.2	\$269.6
NGL pipelines and related storage	290.2	232.2
NGL fractionation	140.6	90.7
Total	\$780.0	\$592.5
Selected volumetric data:		
NGL transportation volumes (MBPD)	2,838	2,536
NGL fractionation volumes (MBPD)	792	708
Equity NGL production (MBPD) (1)	137	122
Fee-based natural gas processing (MMcf/d) (2)	4,715	4,524

(1) Represents the NGL volumes we earn and take title to in connection with our processing activities.

(2) Volumes reported correspond to the revenue streams earned by our gas plants.

Natural gas processing and related NGL marketing activities

Gross operating margin from our natural gas processing and related NGL marketing activities for the first quarter of 2014 increased \$79.6 million when compared to the first quarter of 2013. Gross operating margin from our NGL marketing activities for the first quarter of 2014 increased \$82.1 million when compared to the first quarter of 2013 primarily due to higher sales margins, which accounted for a \$68.3 million increase, and higher sales volumes, which accounted for an additional \$11.1 million increase. Our NGL marketing activities benefitted from the expansion of our Houston Ship Channel LPG export terminal, which we completed in March 2013.

In general, natural gas processing margins were lower in the first quarter of 2014 when compared to the first quarter of 2013 due to higher natural gas prices relative to NGL prices during the first quarter of 2014. Gross operating margin from our South Texas natural gas processing plants increased a net \$10.5 million quarter-to-quarter primarily due to (i) higher processing volumes and equity NGL production, which accounted for an \$8.4 million increase, (ii) higher processing fees, which accounted for a \$7.6 million increase, partially offset by (iii) lower processing margins, which accounted for a \$6.2 million decrease. Our South Texas gas plants continue to benefit from NGL-rich natural gas production from the Eagle Ford Shale. Equity NGL production and fee-based natural gas processing volumes at our South Texas gas plants for the first quarter of 2014 increased 14 MBPD and 183 MMcf/d, respectively, when compared to the first quarter of 2013. Gross operating margin from our Pioneer natural gas processing plant in Wyoming increased a net \$10.1 million quarter-to-quarter primarily due to higher equity NGL production volumes, which accounted for a \$15.7 million increase, partially offset by lower processing margins, which accounted for a \$6.3 million decrease.

Gross operating margin from our Meeker natural gas processing plant in Colorado decreased \$18.2 million quarter-to-quarter primarily due to lower processing margins in the first quarter of 2014. Lastly, gross operating margin from our natural gas processing plants in Louisiana decreased \$9.0 million quarter-to-quarter primarily due to

lower fee-based revenues in the first quarter of 2014.

NGL pipelines and related storage

Gross operating margin from NGL pipelines and related storage assets for the first quarter of 2014 increased \$58.0 million when compared to the first quarter of 2013 primarily due to the start-up of our ATEX pipeline and strong results from our South Texas assets and Mid-America Pipeline System and Seminole Pipeline. Our ATEX pipeline commenced operations in January 2014 and contributed \$30.7 million of gross operating margin during the first quarter of 2014 and 30 MBPD of transportation volumes. Non-GAAP gross operating margin for ATEX for the first quarter of 2014 includes \$18.3 million of transportation revenues associated with shipper make-up rights that are deferred under GAAP and not reflected in our consolidated revenues.

52

Table of Contents

Gross operating margin from our South Texas NGL Pipeline System increased \$11.7 million quarter-to-quarter primarily due to a 137 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 \$6.1 million quarter-to-quarter primarily due to increased volumes. As a result of high demand for export services, loading volumes at our Houston Ship Channel LPG export terminal increased 76 MBPD quarter-to-quarter and volumes transported on the related Channel Pipeline increased 80 MBPD quarter-to-quarter.

Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased a combined \$10.7 million quarter-to-quarter primarily due to higher revenues from ship-or-pay agreements in the first quarter of 2014 associated with the expansion of our Rocky Mountain pipeline. This expansion project went into service in January 2014 and was built to accommodate growing natural gas and NGL production from major supply basins in Colorado, Utah and Wyoming. In the aggregate, transportation volumes for the Mid-America Pipeline System and Seminole Pipeline increased a net 8 MBPD quarter-to-quarter.

Gross operating margin from our Dixie Pipeline and related NGL terminals increased \$5.8 million quarter-to-quarter primarily due to a 28 MBPD increase in transportation volumes, which accounted for \$4.5 million of the increase, and higher transportation and other fees, which accounted for \$1.3 million of the increase. Transportation volumes on the Dixie Pipeline increased quarter-to-quarter primarily due to colder weather during the first quarter of 2014 versus the first quarter of 2013.

NGL fractionation

Gross operating margin from NGL fractionation for the first quarter of 2014 increased \$49.9 million when compared to the first quarter of 2013 primarily due to higher fractionation volumes and fees at our Mont Belvieu complex. Our Mont Belvieu NGL fractionators continue to benefit from increases in mixed NGL volumes produced from domestic shale plays (e.g., the Eagle Ford Shale) and other regions such as the Rocky Mountains. NGL fractionation volumes at our Mont Belvieu complex increased 97 MBPD quarter-to-quarter (net to our ownership interest), which resulted in a \$30.1 million quarter-to-quarter increase in gross operating margin after taking into account associated operating costs. We placed our seventh and eighth NGL fractionators into service at our Mont Belvieu complex during the third and fourth quarters of 2013, respectively. Higher average fractionation and other fees at our Mont Belvieu NGL fractionators accounted for an additional \$19.0 million quarter-to-quarter increase in gross operating margin.

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 periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended March 31,	
	2014	2013
Segment gross operating margin	\$220.4	\$190.8
Selected volumetric data:		
Natural gas transportation volumes (BBtus/d)	12,520	13,071

Gross operating margin from onshore natural gas pipelines and services for the first quarter of 2014 increased \$29.6 million when compared to the first quarter of 2013. Gross operating margin from our Texas Intrastate System increased \$19.9 million quarter-to-quarter primarily due to lower maintenance and other operating costs in the first quarter of 2014, which accounted for a \$10.1 million increase, and a \$10.3 million increase in revenues. Firm capacity reservation fees increased \$3.6 million quarter-to-quarter primarily due to strong demand for our services by

producers in the Eagle Ford Shale supply basin. In addition, transportation revenues increased \$6.0 million quarter-to-quarter primarily due to higher average fees. Natural gas transportation volumes for the Texas Intrastate System increased 184 BBtus/d quarter-to-quarter.

Gross operating margin from our natural gas marketing activities increased \$19.0 million quarter-to-quarter primarily due to higher sales margins and unrealized, non-cash mark-to-market income. In addition, gross operating margin from our San Juan Gathering System increased a net \$5.2 million quarter-to-quarter primarily due to higher

53

Table of Contents

gathering fees, which are indexed to natural gas prices and accounted for a \$6.4 million increase, partially offset by higher maintenance costs, which accounted for a \$2.3 million decrease.

Gross operating margin from our Haynesville Gathering System decreased \$4.4 million quarter-to-quarter primarily due to a 197 BBtus/d decrease in gathering volumes. Gross operating margin from our Acadian Gas System decreased \$3.1 million quarter-to-quarter primarily due to lower transportation fees, which accounted for a \$2.4 million decrease, and higher pipeline integrity costs, which accounted for a \$1.0 million decrease. Transportation volumes for our Acadian Gas System declined a net 162 BBtus/d primarily due to lower volumes from the Haynesville supply basin.

Gross operating margin from our Jonah Gathering System decreased \$4.3 million quarter-to-quarter primarily due to a 144 BBtus/d decrease in gathering volumes, which accounted for a \$3.3 million decrease, and higher operating costs, which accounted for a \$1.6 million decrease. Gross operating margin from our Carlsbad Gathering System decreased \$3.2 million quarter-to-quarter primarily due to higher operating costs, which accounted for a \$1.6 million decrease, and lower natural gas sales margins, which accounted for a \$1.0 million decrease. Lastly, gross operating margin from our Piceance Basin Gathering System decreased \$1.2 million quarter-to-quarter primarily due to higher operating costs in the first quarter of 2014, which accounted for a \$0.9 million decrease. Gathering volumes on the Piceance system decreased 162 BBtus/d quarter-to-quarter, which contributed to a slight decrease in gathering revenues in the first quarter of 2014 when compared to the first quarter of 2013.

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 periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended March 31,	
	2014	2013
Segment gross operating margin	\$159.7	\$236.4
Selected volumetric data:		
Crude oil transportation volumes (MBPD)	1,260	981

Gross operating margin from our onshore crude oil pipelines and services business for the first quarter of 2014 decreased \$76.7 million when compared to the first quarter of 2013. Gross operating margin from our crude oil marketing and related activities decreased \$111.1 million quarter-to-quarter primarily due to lower sales margins, which were primarily caused by the substantial quarter-to-quarter decrease in regional price spreads for crude oil. For example, the average indicative price spread between LLS and WTI crude oil was \$19.56 per barrel for the first quarter of 2013 compared to \$5.75 per barrel for the first quarter of 2014. Gross operating margin from our South Texas Crude Oil Pipeline System and West Texas System increased a combined \$33.3 million quarter-to-quarter primarily due to an aggregate 93 MBPD increase in transportation volumes.

Equity earnings from our investment in the Eagle Ford Crude Oil Pipeline System increased \$8.5 million quarter-to-quarter. This system commenced operations during the second quarter of 2013 and transported 83 MBPD of crude oil (net to our interest) during the first quarter of 2014. Equity earnings from our investment in the Seaway Pipeline decreased \$0.6 million quarter-to-quarter. Transportation volumes on Seaway's Freeport System increased 66 MBPD quarter-to-quarter (net to our interest) primarily due to the timing of a refinery customer's turnaround activities between periods.

Table of Contents

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

	For the Three Months Ended March 31,	
	2014	2013
Segment gross operating margin	\$39.3	\$40.5
Selected volumetric data:		
Natural gas transportation volumes (BBtus/d)	569	733
Platform natural gas processing (MMcf/d)	147	244
Crude oil transportation volumes (MBPD)	335	294
Platform crude oil processing (MBPD)	17	15

Gross operating margin from our offshore pipelines and services business for the first quarter of 2014 decreased \$1.2 million when compared to the first quarter of 2013. In the aggregate, gross operating margin from our Independence Hub platform and Independence Trail pipeline decreased \$5.6 million quarter-to-quarter primarily due to lower platform processing and pipeline throughput volumes during the first quarter of 2014. Natural gas processing volumes on the Independence Hub platform decreased 123 MMcf/d quarter-to-quarter (98 MMcf/d net to our interest) and natural gas transportation volumes on the Independence Trail pipeline decreased 113 BBtus/d quarter-to-quarter.

Equity earnings from our investment in the Cameron Highway Oil Pipeline increased \$2.9 million quarter-to-quarter primarily due to a 38 MBPD increase (net to our interest) in crude oil transportation volumes. In addition, equity earnings from our investment in the Poseidon Oil Pipeline System increased \$1.4 million quarter-to-quarter primarily due to higher transportation fees.

We are beginning to see a crude oil volume response to the pick-up in producer activity in the Gulf of Mexico. Our offshore crude oil pipelines averaged 335 MBPD in the first quarter of 2014, which was the highest since the first quarter of 2010. Currently, there are 40 drilling ships and deepwater semi-submersible drilling rigs active in the Gulf of Mexico region (U.S. waters) and another 16 vessels are expected to arrive before the end of 2015. Approximately half of this drilling fleet will be focused on existing fields, many of which are connected to our assets.

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 periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended March 31,	
	2014	2013
Segment gross operating margin:		
Propylene fractionation and related activities	\$49.0	\$35.0
Butane isomerization and related operations	22.3	23.4
Octane enhancement and related plant operations	0.2	38.3
Refined products pipelines and related activities	42.5	56.6
Marine transportation and other	16.4	17.6
Total	\$130.4	\$170.9

Selected volumetric data:

Propylene fractionation volumes (MBPD)	73	69
Butane isomerization volumes (MBPD)	80	85
Standalone DIB processing volumes (MBPD)	74	50
Octane additive and related plant production volumes (MBPD)	6	16
Transportation volumes, primarily refined products and petrochemicals (MBPD)	703	681

Table of Contents

Propylene fractionation and related activities

Gross operating margin from our propylene fractionation and related activities for the first quarter of 2014 increased \$14.0 million when compared to the first quarter of 2013 primarily due to higher propylene sales margins in the first quarter of 2014.

Butane isomerization and deisobutanizer operations

Gross operating margin from these operations decreased an aggregate \$1.1 million for the first quarter of 2014 when compared to the first quarter of 2013. Gross operating margin from butane isomerization decreased \$3.6 million quarter-to-quarter primarily due to lower volumes, which accounted for a \$2.0 million decrease, and higher maintenance expenses, which accounted for a \$1.3 million decrease. Production volumes at our isomerization facility for the first quarter of 2014 were negatively impacted by unscheduled maintenance at our octane enhancement facility.

Gross operating margin from our standalone deisobutanizers ("DIBs"), which are used to process mixed butanes from our NGL fractionation operations, increased \$2.5 million quarter-to-quarter. We added a new DIB unit at our Mont Belvieu facility in March 2013, which accounted for \$2.2 million of the quarter-to-quarter increase in gross operating margin and a 30 MBPD quarter-to-quarter increase in processing volumes.

Octane enhancement and HPIB plant operations

Gross operating margin from our octane enhancement facility and HPIB plant decreased a combined \$38.1 million quarter-to-quarter. The decrease in gross operating margin is primarily due to an extended period of unscheduled maintenance at the octane enhancement facility during the first quarter of 2014.

Refined products pipelines and related activities

Gross operating margin from our refined products pipelines and related marketing activities for the first quarter of 2014 decreased \$14.1 million when compared to the first quarter of 2013. Gross operating margin from our refined products terminals decreased \$20.5 million quarter-to-quarter primarily due to a \$16.6 million benefit recorded in the first quarter of 2013 for changes in accrued pipeline capacity obligations and a \$4.2 million increase in maintenance costs in the first quarter of 2014 related to a pipeline project. Equity earnings from our investment in the Centennial Pipeline increased \$3.4 million quarter-to-quarter primarily due to its recognition in the first quarter of 2014 of previously deferred transportation revenues. Lastly, results from our refined products marketing activities increased \$2.6 million quarter-to-quarter primarily due to higher sales margins.

Liquidity and Capital Resources

At March 31, 2014, we had \$5.49 billion of consolidated liquidity, which was comprised of \$988.4 million of unrestricted cash on hand and approximately \$4.5 billion of available borrowing capacity under EPO's revolving credit facilities. Unrestricted cash on hand at March 31, 2014 was significantly higher than at December 31, 2013 due to timing of the use of proceeds from our February 2014 senior notes offering. We are still in the process of deploying this cash. Also, our consolidated liquidity amount at March 31, 2014 included \$1.0 billion under EPO's 364-Day Credit Agreement, which EPO elected to terminate on May 1, 2014. Based on current market conditions (as of the filing date of this quarterly 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. We have a universal shelf registration statement (the "2013 Shelf") on file

with the SEC. The 2013 Shelf allows Enterprise Products Partners L.P. and EPO (on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively.

Table of Contents

Consolidated Debt

We had \$18.38 billion of principal amounts outstanding under consolidated debt agreements at March 31, 2014. The following table presents scheduled maturities of our consolidated debt obligations outstanding at March 31, 2014 for the periods indicated (dollars in millions):

	Total	Scheduled Maturities of Debt					
		Remainder of 2014	2015	2016	2017	2018	After 2018
Senior Notes	\$16,850.0	\$650.0	\$1,300.0	\$750.0	\$800.0	\$350.0	\$13,000.0
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Total	\$18,382.7	\$650.0	\$1,300.0	\$750.0	\$800.0	\$350.0	\$14,532.7

We expect to refinance the remaining current maturities of our consolidated debt obligations at or prior to their maturity. See Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report for additional information regarding our consolidated debt.

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. Proceeds from the issuance of Senior Notes JJ and KK were used to repay debt, including amounts then outstanding under EPO's 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 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.

Issuance of Common Units

The following information describes significant transactions that affected our partners' equity accounts during the three months ended March 31, 2014:

At-The-Market Program. We have a registration statement on file 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. During the three months ended March 31, 2014 and 2013, we did not issue any common units under the "at-the-market" program. After taking into account the aggregate sale price of common units sold under our at-the-market program through March 31, 2014, we have the capacity to issue additional common units under this program up to an aggregate sales price of \$1.25 billion.

DRIP and EUPP. We issued a total of 1,307,185 common units under our DRIP during the three months ended March 31, 2014, which generated net cash proceeds of \$81.0 million. After taking into account the number of common units

issued under the DRIP through March 31, 2014, we have the capacity to issue an additional 17,173,693 common units under this plan.

In January 2014, privately held affiliates of EPCO expressed their willingness to consider purchasing through the DRIP a total of \$100 million of our common units during 2014. During the three months ended March 31, 2014, these EPCO affiliates reinvested \$25.0 million, resulting in the issuance of 403,315 common units under our DRIP (this amount being a component of the total common units issued under the DRIP for the three months

57

Table of Contents

ended March 31, 2014). In May 2014, these EPCO affiliates reinvested an additional \$25 million through the DRIP.

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. We issued 31,280 common units under our EUPP during the three months ended March 31, 2014, which generated net cash proceeds of \$2.0 million. After taking into account the number of common units issued under the EUPP through March 31, 2014, we may issue an additional 3,682,164 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 three months ended March 31, 2014 were used to temporarily reduce amounts outstanding under EPO's commercial paper program and for general company purposes.

For additional information regarding our issuance of common units and related registration statements, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Credit Ratings

As of May 9, 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 periods indicated (dollars in millions). For additional information regarding our cash flow amounts, please refer to the Unaudited Condensed Statements of Consolidated Cash Flows included under Part I, Item 1 of this quarterly report.

	For the Three Months Ended March 31,	
	2014	2013
Net cash flows provided by operating activities	\$1,404.1	\$999.9
Cash used in investing activities	861.5	847.2
Cash provided by financing activities	388.9	1,111.5

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 "Risk Factors" under Part I, Item 1A of our 2013 Form 10-K.

Table of Contents

Comparison of Three Months Ended March 31, 2014 with Three Months Ended March 31, 2013

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

Operating Activities. Net cash flows provided by operating activities for the first quarter of 2014 increased \$404.2 million when compared to the first quarter of 2013. The increase in cash provided by operating activities was primarily due to:

§ a \$330.0 million increase in cash attributable to higher partnership income in the first quarter of 2014 compared to the first quarter of 2013 (after adjusting our \$51.4 million quarter-to-quarter increase in net income for changes in the non-cash items identified on our Unaudited Condensed Statements of Consolidated Cash Flows); and

§ a \$20.4 million increase quarter-to-quarter in cash distributions from unconsolidated affiliates primarily due to improved results from our investments in crude oil pipeline joint ventures.

For information regarding significant quarter-to-quarter changes in our consolidated net income and underlying segment results, see "Results of Operations" within this Part I, Item 2.

Investing Activities. Cash used in investing activities for the first quarter of 2014 increased \$14.3 million when compared to the first quarter of 2013. The quarter-to-quarter increase in cash used for investing activities was primarily due to:

§ capital spending for consolidated property, plant and equipment, net of contributions in aid of construction costs, which increased \$72.5 million quarter-to-quarter;

proceeds from asset sales and insurance recoveries, which decreased a combined \$34.2 million quarter-to-quarter.

§ The first quarter of 2014 includes \$95.0 million of nonrefundable insurance proceeds attributable to a February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. The first quarter of 2014 proceeds represent the final installments on these property damage claims. The first quarter of 2013 includes \$8.8 million of nonrefundable insurance proceeds attributable to this incident. In addition, the first quarter of 2013 includes \$86.9 million of proceeds from the sale of a segment of the Seminole Pipeline and \$29.5 million from the sale of chemical trucking assets. Collectively, the foregoing amounts were partially offset by

§ an \$86.1 million quarter-to-quarter inflow of cash related to changes in restricted cash requirements between the first quarters of 2014 and 2013.

Financing Activities. Cash provided by financing activities for the first quarter of 2014 decreased \$722.6 million when compared to the first quarter of 2013. The quarter-to-quarter decrease in cash flows provided by financing activities was primarily due to the following:

§ net cash proceeds from the issuance of common units decreased \$471.1 million quarter-to-quarter. We issued 1,338,465 common units in connection with our DRIP and EUPP during the first quarter of 2014, which generated \$83.0 million of net cash proceeds. This compares to an aggregate 10,475,229 common units we issued in connection with an underwritten offering and our DRIP and EUPP during the first quarter of 2013, which collectively generated \$554.1 million of net cash proceeds;

§ net borrowings under our consolidated debt agreements decreased \$326.5 million quarter-to-quarter. EPO issued \$2.0 billion and repaid \$500.0 million in principal amount of senior notes during the first quarter of 2014, compared

to the issuance of \$2.25 billion and repayment of \$550.0 million in principal amount of senior notes during the first quarter of 2013. In addition, net repayments of short-term notes under EPO's commercial paper program increased \$128.1 million quarter-to-quarter;

59

Table of Contents

cash distributions paid to limited partners during the first quarter of 2014 increased \$61.6 million when compared to the first quarter of 2013 due to increases in both the number of distribution-bearing common units outstanding and the quarterly cash distribution rates per unit; partially offset by

cash outflows related to the monetization of interest rate derivative instruments of \$168.8 million during the first quarter of 2013 compared to none during the first quarter of 2014.

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.

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

	For the Three Months Ended March 31,	
	2014	2013
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	\$695.4	\$622.9
Capital spending for investments in unconsolidated affiliates	284.7	291.4
Total capital spending	\$980.1	\$914.3

Our most significant growth capital expenditures for the three months ended March 31, 2014 were related to (i) projects in Southeast Texas along the Gulf Coast, (ii) expansions of joint venture crude oil pipelines and (iii) the ATEX pipeline.

We currently expect total capital spending for 2014 to be in the range of \$4.0 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 quarterly 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 March 31, 2014, we had approximately \$1.11 billion in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction projects in Texas and the Rocky Mountains.

60

Table of Contents

We placed \$2.5 billion of major capital projects into service during the first quarter of 2014. We expect to complete construction and begin commercial operations of growth capital projects valued at \$2.5 billion over the remainder of 2014. These projects include our:

§ Seaway Pipeline looping project (expected completion in second quarter of 2014);

§ ECHO terminal expansion project (Phase II expected completion in second quarter of 2014);

§ Lateral crude oil pipeline extending from the ECHO terminal to the Beaumont/Port Arthur, Texas area (expected completion in mid-year 2014);

§ Refined products export terminal (expected completion in third quarter of 2014); and

§ SEKCO crude oil pipeline (expected completion in third quarter of 2014).

Pipeline Integrity Costs

Our pipelines are subject to safety programs administered by the U.S. Department of Transportation ("DOT"). This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (e.g., NGL, crude oil, refined products and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs.

The following table summarizes our pipeline integrity costs, including those attributable to DOT regulations, for the periods indicated (dollars in millions):

	For the Three Months Ended March 31, 2014 2013	
Expensed	\$9.0	\$10.7
Capitalized	9.3	12.8
Total	\$18.3	\$23.5

We expect the cost of our pipeline integrity program, regardless of whether such costs are capitalized or expensed, to approximate \$117.0 million for the remainder of 2014. The cost of our pipeline integrity program was \$124.3 million for the year ended December 31, 2013.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our 2013 Form 10-K. The following estimates, in our opinion, are subjective in nature, require the exercise of professional judgment and involve complex analysis:

§ depreciation methods and estimated useful lives of property, plant and equipment;

§ measuring recoverability of long-lived assets and equity method investments;

§ amortization methods and estimated useful lives of qualifying intangible assets;

§ methods we employ to measure the fair value of goodwill; and

§ revenue recognition policies and the use of estimates for revenue and expenses.

When used to prepare our Unaudited Condensed Consolidated Financial Statements, the foregoing types of estimates are based on our current knowledge and understanding of the underlying facts and circumstances. Such

61

Table of Contents

estimates may be revised as a result of changes in the underlying facts and circumstances. Subsequent changes in these estimates may have a significant impact on our consolidated financial position, results of operations and cash flows.

Other Items

Use of Non-GAAP Financial Measures

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

	For the Three Months Ended March 31,	
	2014	2013
NGL Pipelines & Services	\$780.0	\$592.5
Onshore Natural Gas Pipelines & Services	220.4	190.8
Onshore Crude Oil Pipelines & Services	159.7	236.4
Offshore Pipeline & Services	39.3	40.5
Petrochemical & Refined Products Services	130.4	170.9
Total segment gross operating margin	\$1,329.8	\$1,231.1

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 Three Months Ended March 31,	
	2014	2013
Total segment gross operating margin	\$1,329.8	\$1,231.1
Adjustments to reconcile total segment gross operating margin to operating income:		
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(301.4)	(276.8)
Subtract impairment charges not reflected in gross operating margin	(8.8)	(11.0)
Add net gains attributable to asset sales and insurance recoveries not reflected in gross operating margin	89.6	63.9
Subtract non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	(23.3)	--
Subtract general and administrative costs not reflected in gross operating margin	(53.2)	(49.5)
Operating income	1,032.7	957.7
Other expense, net	(221.2)	(196.0)
Income before income taxes	\$811.5	\$761.7

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.

For additional information regarding gross operating margin, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report.

Contractual Obligations

With the exception of routine fluctuations in the balances of our revolving credit facility and commercial paper notes, the issuance of Senior Notes JJ and KK in February 2014 and the scheduled repayment of maturing debt obligations, there have been no significant changes in our consolidated debt obligations since those reported in our 2013 Form 10-K. See Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements under

62

Table of Contents

Part I, Item 1 of this quarterly report for information regarding our consolidated debt obligations. There were no material changes in our operating lease or purchase obligations since those reported in our 2013 Form 10-K.

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 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Insurance Matters

In February 2011, we experienced an NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. We collected \$95.0 million and \$8.8 million of nonrefundable cash insurance proceeds attributable to this incident during the three months ended March 31, 2014 and 2013, respectively. The payments we received during the first quarter of 2014 represent the final installments on this property damage claim.

Operating income for the three months ended March 31, 2014 and 2013 includes \$95.0 million and \$8.8 million, respectively, of gains related to these insurance recoveries. To the extent that nonrefundable cash insurance proceeds related to this incident were received, we recorded gains equal to such proceeds.

For additional information regarding insurance matters, see Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Recent Litigation Developments

For information regarding recent litigation developments, see Part II, Item 1 of this quarterly report.

Item 3. 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.

Our exposures to market risk have not changed materially since those reported under Part II, Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," included in our 2013 Form 10-K.

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

63

Table of Contents

§ 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 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly 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 March 31, 2014 (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):

Scenario	Resulting Classification	Interest Rate Swap Portfolio Aggregate Fair Value at		
		December 31, 2013	March 31, 2014	April 15, 2014
FV assuming no change in underlying interest rates	Asset	\$24.8	\$20.9	\$24.4
FV assuming 10% increase in underlying interest rates	Asset	24.1	20.2	23.8
FV assuming 10% decrease in underlying interest rates	Asset	25.5	21.5	25.0

Table of Contents

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 March 31, 2014 (volume measures as noted):

Derivative Purpose	Volume (1)		Accounting Treatment
	Current (2)	Long-Term (2)	
<u>Derivatives designated as hedging instruments:</u>			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	2.6	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls) (3)	0.9	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	0.1	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	2.5	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities (Bcf)	0.3	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	4.4	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	2.3	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	1.3	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.7	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)	4.8	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	6.9	n/a	Cash flow hedge
<u>Derivatives not designated as hedging instruments:</u>			
Natural gas risk management activities (Bcf) (4,5)	80.9	17.6	Mark-to-market
Refined products risk management activities (MMBbls) (5)	0.7	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (5)	15.8	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 March 2015, June 2014 and October 2016, respectively.

(3) Forecasted sales of NGL volumes under natural gas processing exclude 0.9 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.

(4) Current volumes include 41.4 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.

(5) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

As of April 30, 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 the primary objectives of these four 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.

65

Table of Contents

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):

Scenario	Resulting Classification	Portfolio Fair Value at		
		December 31, 2013	March 31, 2014	April 15, 2014
FV assuming no change in underlying commodity prices	Asset (Liability)	\$(1.3)	\$ 4.0	\$ 2.9
FV assuming 10% increase in underlying commodity prices	(Liability)	(6.7)	2.7	1.6
FV assuming 10% decrease in underlying commodity prices	Asset	4.1	5.2	4.2

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):

Scenario	Resulting Classification	Portfolio Fair Value at		
		December 31, 2013	March 31, 2014	April 15, 2014
FV assuming no change in underlying commodity prices	Liability	\$(20.7)	\$(9.5)	\$(20.4)
FV assuming 10% increase in underlying commodity prices	Liability	(69.8)	(38.2)	(54.3)
FV assuming 10% decrease in underlying commodity prices	Asset	28.5	19.1	13.5

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):

Scenario	Resulting Classification	Portfolio Fair Value at		
		December 31, 2013	March 31, 2014	April 15, 2014
FV assuming no change in underlying commodity prices	Asset	\$8.2	\$7.0	\$5.7
FV assuming 10% increase in underlying commodity prices	Liability	(9.8)	(13.5)	(13.4)
FV assuming 10% decrease in underlying commodity prices	Asset	26.1	27.4	24.7

Table of Contents

Item 4. Controls and Procedures.

Disclosure Controls and Procedures

As of the end of the period covered by this quarterly 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 quarterly report, Mr. Creel and Mr. Fowler concluded:

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 (i) 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 first quarter of 2014, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

The required certifications of Mr. Creel and Mr. Fowler under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 are included as exhibits to this quarterly report (see Exhibits 31 and 32 under Part II, Item 6 of this quarterly report).

PART II. OTHER INFORMATION

Item 1. 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 will vigorously defend the partnership in litigation matters.

ETP Matter

In connection with a proposed pipeline project, we and Energy Transfer Partners, L.P. ("ETP") signed a non-binding letter of intent in April 2011 that disclaimed any partnership or joint venture related to such project absent executed definitive documents and board approvals of the respective companies. Definitive agreements were never executed and board approval was never obtained for the potential pipeline project. In August 2011, the proposed pipeline project was cancelled due to a lack of customer support.

In September 2011, ETP filed suit against us and a third party in connection with the cancelled project alleging, among other things, that we and ETP had formed a "partnership." The case was tried in the District Court of Dallas

County, Texas, 298th Judicial District. While we firmly believe, and argued during our defense, that no agreement was ever executed forming a legal joint venture or partnership between the parties, the jury found that the actions of the two companies, nevertheless, constituted a legal partnership. As a result, the jury found that ETP was wrongfully excluded from a subsequent pipeline project involving a third party, and awarded ETP \$319.4 million in actual damages on March 4, 2014. On April 21, 2014, ETP filed a motion with the court for entry of judgment

67

Table of Contents

against us in an aggregate amount of approximately \$914.7 million plus prejudgment interest, which aggregate amount includes (i) the amount of actual damages awarded by the jury and (ii) an additional \$595.3 million in disgorgement for the alleged benefit we received due to a breach of fiduciary duties by us against ETP. A judgment has not yet been entered in this case.

We do not believe that the verdict or the plaintiff's motion for judgment is supported by the evidence or the law and intend to vigorously oppose any judgment based on such verdict or the plaintiff's motion for judgment. As of March 31, 2014, we have not recorded a provision for this matter as management believes payment of damages in this case is not probable.

Environmental Matters

On occasion, we are assessed monetary sanctions by governmental authorities related to administrative or judicial proceedings involving environmental matters. The following information summarizes matters arising during the three months ended March 31, 2014 (or updates to previous disclosures) 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 Unaudited Condensed Consolidated Financial Statements.

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 are expected to result in monetary sanctions of approximately \$0.3 million, which reflects an increase of \$0.2 million from the estimate presented in our 2013 Form 10-K.

In February 2014, the Colorado Department of Public Health and Environment issued a Compliance Advisory in § connection with alleged air permit violations at our Meeker natural gas processing plant. We believe that the eventual resolution of these matters may result in monetary sanctions in excess of \$0.1 million.

For more information regarding our litigation matters, see "Litigation" under Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report, which subsection is incorporated by reference into this Part II, Item 1.

Item 1A. Risk Factors.

Security holders and potential investors in our securities should carefully consider the risk factors set forth in our 2013 Form 10-K, in addition to other information in such annual report. The risk factors set forth in our 2013 Form 10-K are important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

The following table summarizes our repurchase activity during the three months ended March 31, 2014:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly	Maximum Number of Units That May Yet Be Purchased
--------	--	--------------------------------------	--	---

			Announced Plans	Under the Plans
February 2014 (1)	421,391	\$ 65.69	--	--

(1) Of the 1,239,862 restricted common units that vested in February 2014 and converted to common units, 421,391 units were sold back to us by employees to cover related withholding tax requirements.

Table of Contents

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

None.

Item 6. 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	

Edgar Filing: ENTERPRISE PRODUCTS PARTNERS L P - Form 10-Q

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).

Table of Contents

- 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).
 Agreement and Plan of Merger, dated as of April 28, 2011, by and among Enterprise Products Partners L.P.,
- 2.11 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).
 Certificate of Amendment to Certificate of Limited Partnership of Enterprise Products Partners L.P., filed on
- 3.2 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).
 Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products
- 3.4 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).
 Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC)
- 3.5 (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).
 Certificate of Amendment to Certificate of Formation of Enterprise Products Holdings LLC (formerly named
- 3.6 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).
 Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC dated
- 3.7 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).
 Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products
- 4.2 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).
 First Supplemental Indenture, dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer,
- 4.3 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).
 Second Supplemental Indenture, dated as of February 14, 2003, among Enterprise Products Operating L.P., as
- 4.4 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).
 Third Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original
- 4.5 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).
 Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products
- 4.6 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).

Table of Contents

- Third Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, 4.7 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).
- Fourth Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as 4.8 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).
- Fifth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, 4.9 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).
- Sixth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, 4.10 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).
- Eighth Supplemental Indenture, dated as of July 18, 2006, among Enterprise Products Operating L.P., as Issuer, 4.11 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).
- Ninth Supplemental Indenture, dated as of May 24, 2007, among Enterprise Products Operating L.P., as Issuer, 4.12 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).
- Tenth Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original 4.13 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).
- Eleventh Supplemental Indenture, dated as of September 4, 2007, among Enterprise Products Operating LLC, as 4.14 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).
- Twelfth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, 4.15 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).
- Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as 4.16 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).
- Fourteenth Supplemental Indenture, dated as of December 8, 2008, among Enterprise Products Operating LLC, as 4.17 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).
- Sixteenth Supplemental Indenture, dated as of October 5, 2009, among Enterprise Products Operating LLC, as 4.18 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).
- Seventeenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, 4.19 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).
- Eighteenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as 4.20 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).

Table of Contents

- Nineteenth Supplemental Indenture, dated as of May 20, 2010, among Enterprise Products Operating LLC, as
4.21 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).
- Twentieth Supplemental Indenture, dated as of January 13, 2011, among Enterprise Products Operating LLC, as
4.22 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).
- Twenty-First Supplemental Indenture, dated as of August 24, 2011, among Enterprise Products Operating LLC,
4.23 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).
- Twenty-Second Supplemental Indenture, dated as of February 15, 2012, among Enterprise Products Operating
4.24 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).
- Twenty-Third Supplemental Indenture, dated as of August 13, 2012, among Enterprise Products Operating LLC,
4.25 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).
- Twenty-Fourth Supplemental Indenture, dated as of March 18, 2013, among Enterprise Products Operating LLC,
4.26 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).
- Twenty-Fifth Supplemental Indenture, dated as of February 12, 2014, among Enterprise Products Operating LLC,
4.27 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).
- Form of Global Note representing \$350.0 million principal amount of 6.375% Series B Senior Notes due 2013
4.28 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).
- Form of Global Note representing \$499.2 million principal amount of 6.875% Series B Senior Notes due 2033
4.29 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 10-K filed March 31, 2003).
- Form of Global Note representing \$500.0 million principal amount of 5.60% Series B Senior Notes due 2014
4.30 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
- Form of Global Note representing \$150.0 million principal amount of 5.60% Series B Senior Notes due 2014
4.31 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
- Form of Global Note representing \$350.0 million principal amount of 6.65% Series B Senior Notes due 2034
4.32 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
- Form of Global Note representing \$250.0 million principal amount of 5.00% Series B Senior Notes due 2015
4.33 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed November 4, 2005).
- Form of Global Note representing \$250.0 million principal amount of 5.75% Series B Senior Notes due 2035
4.34 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed November 4, 2005).
- Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K
4.35 filed July 19, 2006).
- Form of Global Note representing \$800.0 million principal amount of 6.30% Senior Notes due 2017 with
4.36 attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 9, 2007).

Table of Contents

- 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).

Table of Contents

- 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).

Table of Contents

- 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).

12.1#

Computation of ratio of earnings to fixed charges for the three months ended March 31, 2014 and for each of the five years ended December 31, 2013, 2012, 2011, 2010 and 2009.

Table of Contents

31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the three months ended March 31, 2014.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the three months ended March 31, 2014.
32.1#	Sarbanes-Oxley Section 906 certification of Michael A. Creel for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the three months ended March 31, 2014.
32.2#	Sarbanes-Oxley Section 906 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the three months ended March 31, 2014.
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.

#Filed with this report.

Table of Contents

SIGNATURES

Pursuant to the requirements 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 May 9, 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