ENTERPRISE PRODUCTS PARTNERS L P
Form 10-Q
August 08, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2013

OR

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

For the transition period from ___ to ___.

Commission file number: 1-14323

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

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

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

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

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

Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 þ 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 þ	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

Yes o No þ

There were 915,422,738 common units and 4,520,431 Class B units (which generally vote together with the common units) of Enterprise Products Partners L.P. outstanding at July 31, 2013. Our common units trade on the New York Stock Exchange under the ticker symbol "EPD."

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PART I. FINANCIAL INFORMATION.

Item 1. Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

ASSETS	June 30, 2013	December 31, 2012
Current assets:		
Cash and cash equivalents	$45.3	$16.1
Restricted cash	26.3	4.3
Accounts receivable – trade, net of allowance for doubtful accounts of $12.2 at June 30, 2013 and $13.2 at December 31, 2012	4,651.5	4,350.9
Accounts receivable – related parties	19.8	2.5
Inventories	1,411.4	1,088.4
Prepaid and other current assets	425.7	380.9
Total current assets	6,580.0	5,843.1
Property, plant and equipment, net	25,566.1	24,846.4
Investments in unconsolidated affiliates	1,938.8	1,394.6
Intangible assets, net of accumulated amortization of $1,098.0 at June 30, 2013 and $1,050.0 at December 31, 2012	1,513.2	1,566.8
Goodwill	2,080.0	2,086.8
Other assets	198.8	196.7
Total assets	$37,876.9	$35,934.4
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 9)	$540.0	$1,546.6
Accounts payable – trade	777.4	764.5
Accounts payable – related parties	142.0	127.1
Accrued product payables	4,770.4	4,476.2
Accrued interest	303.6	300.8
Other current liabilities	339.7	540.5
Total current liabilities	6,873.1	7,755.7
Long-term debt (see Note 9)	16,429.6	14,655.2
Deferred tax liabilities	37.2	22.5
Other long-term liabilities	184.2	205.0
Commitments and contingencies (see Note 14)		
Equity: (see Note 10)		
Partners' equity:		
Limited partners:		
Common units (915,434,963 units outstanding at June 30, 2013 and 898,813,337 units outstanding at December 31, 2012)	14,400.4	13,439.6
Class B units (4,520,431 units outstanding at June 30, 2013 and December 31, 2012)	118.5	118.5
Total limited partners' equity	14,518.9	13,558.1
Accumulated other comprehensive loss	(363.0)	(370.4)
Total partners' equity	14,155.9	13,187.7

Noncontrolling interests	196.9	108.3
Total equity	14,352.8	13,296.0
Total liabilities and equity	$37,876.9	$35,934.4

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Revenues:				
Third parties	$11,142.6	$9,764.2	$22,519.8	$20,985.9
Related parties	6.7	25.6	12.6	56.4
Total revenues (see Note 11)	11,149.3	9,789.8	22,532.4	21,042.3
Costs and expenses:				
Operating costs and expenses:				
Third parties	10,143.0	8,788.0	20,349.2	19,106.8
Related parties	224.2	221.5	438.4	369.9
Total operating costs and expenses	10,367.2	9,009.5	20,787.6	19,476.7
General and administrative costs:				
Third parties	17.5	16.7	37.2	40.3
Related parties	28.0	25.8	57.8	48.5
Total general and administrative costs	45.5	42.5	95.0	88.8
Total costs and expenses (see Note 11)	10,412.7	9,052.0	20,882.6	19,565.5
Equity in income of unconsolidated affiliates	37.6	11.3	82.1	21.2
Operating income	774.2	749.1	1,731.9	1,498.0
Other income (expense):				
Interest expense	(200.2)	(186.6)	(396.1)	(373.1)
Interest income	0.3	0.1	0.5	0.4
Other, net (see Note 2)	(0.6)	13.1	(0.9)	71.5
Total other expense, net	(200.5)	(173.4)	(396.5)	(301.2)
Income before income taxes	573.7	575.7	1,335.4	1,196.8
Benefit from (provision for) income taxes (see Note 2)	(20.4)	(8.5)	(26.8)	25.9
Net income	553.3	567.2	1,308.6	1,222.7
Net income attributable to noncontrolling interests (see Note 10)	(0.8)	(0.9)	(2.6)	(5.1)
Net income attributable to limited partners	$552.5	$566.3	$1,306.0	$1,217.6
Earnings per unit: (see Note 13)				
Basic earnings per unit	$0.62	$0.66	$1.48	$1.42
Diluted earnings per unit	$0.60	$0.64	$1.43	$1.37

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Net income	$553.3	$567.2	$1,308.6	$1,222.7
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instruments:				
Changes in fair value of cash flow hedges	34.1	105.0	(13.5)	45.4
Reclassification of gains and losses to net income	(7.2)	14.2	0.1	36.2
Interest rate derivative instruments:				
Changes in fair value of cash flow hedges	--	(84.0)	6.7	(55.1)
Reclassification of losses to net income	7.8	3.7	13.7	6.4
Total cash flow hedges	34.7	38.9	7.0	32.9
Change in funded status of pension and postretirement plans, net of tax	0.4	--	0.4	(1.2)
Proportionate share of other comprehensive income of unconsolidated affiliate	--	--	--	1.0
Change in fair value of available-for-sale equity securities	--	(15.8)	--	--
Total other comprehensive income	35.1	23.1	7.4	32.7
Comprehensive income	588.4	590.3	1,316.0	1,255.4
Comprehensive income attributable to noncontrolling interests	(0.8)	(0.9)	(2.6)	(5.1)
Comprehensive income attributable to limited partners	$587.6	$589.4	$1,313.4	$1,250.3

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Six Months Ended June 30,	
	2013	2012
Operating activities:		
Net income	$1,308.6	$1,222.7
Reconciliation of net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	599.8	537.7
Non-cash asset impairment charges	38.1	14.5
Equity in income of unconsolidated affiliates	(82.1)	(21.2)
Distributions received from unconsolidated affiliates	119.3	50.5
Gains attributable to asset sales and insurance recoveries (see Note 16)	(58.2)	(100.3)
Deferred income tax expense (benefit)	14.8	(64.9)
Changes in fair market value of derivative instruments	(1.2)	(21.6)
Net effect of changes in operating accounts (see Note 16)	(409.2)	(280.3)
Other operating activities	1.0	1.2
Net cash flows provided by operating activities	1,530.9	1,338.3
Investing activities:		
Capital expenditures	(1,447.3)	(1,813.1)
Contributions in aid of construction costs	14.9	10.0
Decrease (increase) in restricted cash	(22.0)	38.5
Investments in unconsolidated affiliates	(547.9)	(125.5)
Proceeds from asset sales and insurance recoveries (see Note 16)	199.2	1,156.7
Other investing activities	0.5	(16.4)
Cash used in investing activities	(1,802.6)	(749.8)
Financing activities:		
Borrowings under debt agreements	7,064.5	2,414.6
Repayments of debt	(6,281.6)	(1,891.0)
Debt issuance costs	(23.7)	(7.5)
Monetization of interest rate derivative instruments (see Note 4)	(168.8)	(77.6)
Cash distributions paid to limited partners (see Note 10)	(1,171.9)	(1,068.6)
Cash distributions paid to noncontrolling interests	(4.7)	(8.1)
Cash contributions from noncontrolling interests (see Note 10)	95.9	5.9
Net cash proceeds from the issuance of common units	835.4	61.5
Acquisition of treasury units	(35.8)	(19.1)
Other financing activities	(8.4)	(3.9)
Cash provided by (used in) financing activities	300.9	(593.8)
Net change in cash and cash equivalents	29.2	(5.3)
Cash and cash equivalents, January 1	16.1	19.8
Cash and cash equivalents, June 30	$45.3	$14.5

See Notes to Unaudited Condensed Consolidated Financial Statements.

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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			
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance, December 31, 2012	$13,558.1	$ (370.4)	$ 108.3	$13,296.0
Net income	1,306.0	--	2.6	1,308.6
Cash distributions paid to limited partners	(1,171.9)	--	--	(1,171.9)
Cash distributions paid to noncontrolling interests	--	--	(4.7)	(4.7)
Cash contributions from noncontrolling interests	--	--	95.9	95.9
Net cash proceeds from the issuance of common units	835.4	--	--	835.4
Amortization of fair value of equity-based awards	35.6	--	--	35.6
Cash flow hedges	--	7.0	--	7.0
Other	(44.3)	0.4	(5.2)	(49.1)
Balance, June 30, 2013	$14,518.9	$ (363.0)	$ 196.9	$14,352.8

	Partners' Equity			
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance, December 31, 2011	$12,464.8	$ (351.4)	$ 105.9	$12,219.3
Net income	1,217.6	--	5.1	1,222.7
Cash distributions paid to limited partners	(1,068.6)	--	--	(1,068.6)
Cash distributions paid to noncontrolling interests	--	--	(8.1)	(8.1)
Cash contributions from noncontrolling interests	--	--	5.9	5.9
Net cash proceeds from the issuance of common units	61.5	--	--	61.5
Amortization of fair value of equity-based awards	31.8	--	--	31.8
Cash flow hedges	--	32.9	--	32.9
Other	(22.1)	(0.2)	1.0	(21.3)
Balance, June 30, 2012	$12,685.0	$ (318.7)	$ 109.8	$12,476.1

See Notes to Unaudited Condensed Consolidated Financial Statements.

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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 Texas limited liability company.

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

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

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

Note 1. Partnership Operations, Organization and Basis of Presentation

General

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

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; 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 50,000 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, 21 NGL and propylene fractionators, six offshore hub platforms located in the Gulf of Mexico, a butane isomerization complex, NGL import and export terminals, and octane enhancement and high-purity isobutylene production facilities.

We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services. All activities included in our former sixth reportable business segment, Other Investments, ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our previously held investment in Energy Transfer Equity L.P. (together with its subsidiaries, "Energy Transfer Equity") (see "Liquidation of Investment in Energy Transfer Equity" under Note 7).

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 and six months ended June 30, 2013 are not necessarily indicative of results expected for the full year of 2013. 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, 2012 (the "2012 Form 10-K") filed with the SEC on March 1, 2013.

Allowance for Doubtful Accounts

Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts. The following table presents our allowance for doubtful accounts activity for the periods indicated:

	For the Six Months Ended June 30,	
	2013	2012
Balance at beginning of period	$13.2	$13.4
Charged to costs and expenses	0.4	--
Deductions	(1.4)	(0.4)
Balance at end of period	$12.2	$13.0

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 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 contract 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.

Provision for Income Taxes

Provision for income taxes for the second quarter of 2013 increased $11.9 million when compared to the second quarter of 2012 primarily due to Texas Margin Tax accruals. In June 2013, the State of Texas enacted certain changes to the Texas Margin Tax which lowered the tax rate and expanded the scope of depreciation deductions. As a result of these changes, current income tax expense decreased $7.2 million and our deferred income tax expense (related to book/tax depreciation timing differences) increased $20.3 million, for a net $13.1 million expense in the second quarter of 2013.

We recognized a net income tax expense of $26.8 million for the first six months of 2013 compared to a net income tax benefit of $25.9 million for the same period in 2012. The $52.7 million period-to-period change is primarily due to (i) a $46.5 million benefit recorded in the first quarter of 2012 related to the conversion of certain of our subsidiaries to limited liability companies and (ii) the $13.1 million of expense recorded in June 2013 related to the Texas Margin Tax (as discussed above).

The $46.5 million net income tax benefit recorded in 2012 is attributable to the difference between deferred income taxes accrued by the applicable subsidiaries through the date of conversion and any current income tax due in connection with the conversions. After taking into account certain tax loss carryforward amounts, we paid $22.0 million in federal income taxes in connection with the conversions.

Other Non-Operating Income (Expense)

The following table presents the components of "Other, net" as presented on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Gain on sales of available-for-sale securities of Energy Transfer Equity (1)	$ --	$ 15.5	$ --	$ 68.8
Distribution income from Energy Transfer Equity	--	--	--	4.1
Other	(0.6)	(2.4)	(0.9)	(1.4)
Total	$ (0.6)	$ 13.1	$ (0.9)	$ 71.5

(1) See Note 7 for information regarding the liquidation of our investment in limited partnership units of Energy Transfer Equity.

Restricted Cash

Restricted cash represents amounts held in bank accounts as margin in support of our commodity derivative instruments portfolio and related physical natural gas, crude oil, refined products and NGL purchases. Additional cash may be restricted to maintain this portfolio as commodity prices fluctuate or deposit requirements change. At June 30, 2013 and December 31, 2012, our restricted cash amounts were $26.3 million and $4.3 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 the compensation expense we recognized in connection with equity-based awards for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Restricted common unit awards	$18.3	$15.7	$34.9	$30.5
Unit option awards	0.2	0.3	0.6	1.0
Other (1)	0.1	0.5	0.3	1.4

Total	$18.6	$16.5	$35.8	$32.9

(1) Primarily represents expense associated with unit appreciation rights ("UARs"), phantom units and similar awards.

The fair value of equity-classified awards (e.g., restricted common unit and unit option awards) is amortized to earnings over the requisite service or vesting period. Compensation expense for liability-classified awards (e.g., UARs and phantom units) is recognized over the requisite service or vesting period based on the fair value of the award remeasured at each reporting date. Liability-classified awards are settled in cash upon vesting.

At June 30, 2013, EPCO's significant long-term incentive plans applicable to us were the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan") and the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan"). After giving effect to awards granted under the 1998 Plan and 2008 Plan through June 30, 2013, a total of 1,155,077 and 4,307,512 additional common units could be issued under these plans, respectively.

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ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Restricted Common Unit Awards

Restricted common unit awards allow recipients to acquire our common units (at no cost to the recipient apart from service or other conditions) once a defined vesting period expires, subject to customary forfeiture provisions. As used in the context of EPCO's long-term incentive plans, the term "restricted common unit" represents a time-vested unit. Restricted common unit awards generally vest at a rate of 25% per year beginning one year after the grant date. Such awards are non-vested until the required service period expires. Restricted common units are included in the number of common units presented on our Unaudited Condensed Consolidated Balance Sheets.

The fair value of a restricted common unit award is based on the market price per unit of the underlying security on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

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

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted common units at December 31, 2012	3,893,486	$ 40.87
Granted (2,3)	1,748,476	$ 57.15
Vested (3)	(1,830,010)	$ 34.71
Forfeited	(120,882)	$ 45.98
Restricted common units at June 30, 2013	3,691,070	$ 51.46

(1) Determined by dividing the aggregate grant date fair value of awards (before an allowance for forfeitures) by the number of awards issued.
(2) The aggregate grant date fair value of restricted common unit awards issued during 2013 was $99.9 million based on a grant date market price of our common units ranging from $57.11 to $59.74 per unit. An estimated annual forfeiture rate of 3.9% was applied to these awards.
(3) Includes awards granted to the independent directors of the board of directors of Enterprise GP as part of their annual compensation for 2013. A total of 9,296 restricted common unit awards were issued to the independent directors of Enterprise GP, which immediately vested upon issuance.

Typically, each recipient is also entitled to nonforfeitable cash distributions equal to the product of the number of restricted common units outstanding for the participant and the cash distribution per unit paid to limited partners. Since these restricted common units are participating securities, such distributions are included in "Cash distributions paid to limited partners" as presented on our Unaudited Condensed Statements of Consolidated Cash Flows.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Cash distributions paid to restricted common unitholders	$3.0	$3.0	$5.6	$5.4
Total intrinsic value of restricted common unit awards that vested during period	54.0	30.1	106.4	62.7

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate $109.4 million at June 30, 2013, of which our allocated share of the cost is currently estimated to be $100.3 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.1 years.

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Unit Option Awards

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options. These unit option awards are denominated in our common units. When issued, the exercise price of each unit option award may be no less than the market price of our common units on the date of grant. In general, unit option awards have a vesting period of four years from the date of grant and expire at the end of the calendar year following the year of vesting (e.g., an option vesting on May 29, 2012 will expire on December 31, 2013). However, unit option awards only become exercisable at certain times during the calendar year following the year in which they vest (typically the months of February, May, August and November).

The fair value of each unit option award is estimated on the date of grant using a Black-Scholes option pricing model. Compensation expense recorded in connection with unit option awards is based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period. The following table presents unit option award activity for the 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, 2012	2,761,140	$ 27.41	2.0	$ 13.0
Exercised	(736,140)	$ 29.95		
Unit option awards at June 30, 2013	2,025,000	$ 26.49	1.8	$ 51.4
Options exercisable at June 30, 2013	--	$ --	--	$ --

(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 June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Total intrinsic value of unit option awards exercised during period	$3.4	$ --	$19.8	$14.0
Cash received from EPCO in connection with the exercise of unit option awards	2.0	--	11.5	10.2
Unit option award-related cash reimbursements to EPCO	3.4	--	19.8	14.0

For the EPCO group of companies, the unrecognized compensation cost associated with unit option awards was an aggregate $0.3 million at June 30, 2013, of which our allocated share of the cost is currently estimated to be $0.3

million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 0.6 years.

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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.

We are required to recognize derivative instruments at fair value as either assets or liabilities on our Unaudited Condensed Consolidated Balance Sheets unless such instruments meet certain normal purchase/normal sale criteria. While all derivatives are required to be reported at fair value on the balance sheet, changes in fair value of derivative instruments are reported in different ways, depending on the nature and effectiveness of the hedging activities to which they relate. After meeting specified conditions, a qualified derivative may be designated as a total or partial hedge of:

§ Changes in the fair value of a recognized asset or liability, or an unrecognized firm commitment – In a fair value hedge, gains and losses for both the derivative instrument and the hedged item are recognized in income during the period of change.

§ Variable cash flows of a forecasted transaction – In a cash flow hedge, the effective portion of the hedge is reported in other comprehensive income (loss) and is reclassified into earnings when the forecasted transaction affects earnings.

An effective hedge relationship is one in which the change in fair value of a derivative instrument can be expected to offset 80% to 125% of the changes in fair value of a hedged item at inception and throughout the life of the hedging relationship. The effective portion of a hedge relationship is the amount by which the derivative instrument exactly offsets the change in fair value of the hedged item during the reporting period. Conversely, ineffectiveness represents the change in the fair value of the derivative instrument that does not exactly offset the change in the fair value of the hedged item. Any ineffectiveness associated with a hedge relationship is recognized in earnings immediately. Ineffectiveness can be caused by, among other things, changes in the timing of forecasted transactions or a mismatch of terms between the derivative instrument and the hedged item.

A contract designated as a cash flow hedge of an anticipated transaction that is not probable of occurring is immediately recognized in earnings.

Certain of our derivative instruments do not qualify for hedge accounting treatment; therefore, they are accounted for using mark-to-market accounting.

Interest Rate Hedging Activities

We may utilize interest rate swaps, forward starting swaps and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy is a component in controlling our overall cost of capital associated with such borrowings. Interest rate swaps exchange the stated interest rate paid on a notional amount of existing debt for the fixed or floating interest rate stipulated in the derivative instrument. Forward starting swaps perform a similar function except that they are associated with interest rates underlying anticipated future issuances of debt.

The following table summarizes our portfolio of interest rate swaps at June 30, 2013:

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes AA	10 fixed-to-floating swaps	$ 750.0	1/2011 to 2/2016	3.2% to 1.3%	Fair value hedge
Undesignated swaps	6 floating-to-fixed swaps	$ 600.0	5/2010 to 7/2014	0.3% to 2.0%	Mark-to-market

In February 2012, we settled 11 fixed-to-floating interest rate swaps having an aggregate notional amount of $800.0 million, resulting in gains totaling $37.7 million. These gains are being amortized to earnings (as a decrease in interest expense) using the effective interest method over the forecasted hedged period of three years.

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At December 31, 2012, our portfolio of forward starting interest rate swaps consisted of 16 derivative instruments having an aggregate notional amount of $1.0 billion. Forward starting swaps hedge the expected underlying benchmark interest rates related to future issuances of debt. We accounted for these derivative instruments as cash flow hedges. In connection with the issuance of Senior Notes II and HH in March 2013 (see Note 9), we settled all 16 forward starting swaps that were outstanding at December 31, 2012, which resulted in cash payments totaling $168.8 million. These losses are a component of accumulated other comprehensive income and are being amortized to earnings (as an increase in interest expense) over the forecasted hedge period of ten years using the effective interest method.

In connection with the issuance of Senior Notes EE in February 2012, we settled ten forward starting swaps having an aggregate notional amount of $500.0 million, resulting in cash payments totaling $115.3 million. These losses are a component of accumulated other comprehensive income 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.

Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps, basis swaps and option contracts. The following table summarizes our portfolio of commodity derivative instruments outstanding at June 30, 2013 (volume measures as noted):

	Volume (1)		Accounting
Derivative Purpose	Current (2)	Long-Term (2)	Treatment
Derivatives designated as hedging instruments:			
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	1.1	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	2.2	0.1	Cash flow hedge
Natural gas marketing:			
Forecasted sales of natural gas (Bcf)	2.3	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	10.0	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	3.3	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	7.1	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.1	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	0.1	n/a	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	2.6	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	3.0	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	145.7	24.0	Mark-to-market
Refined products risk management activities (MMBbls) (4)	0.5	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	8.5	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is January 2015, February 2014 and March 2016, respectively.
(3) Current and long-term volumes include 63.9 Bcf and 1.2 Bcf, respectively, of physical derivative instruments that are predominantly priced at a marked-based index plus a premium or minus a discount related to location differences.
(4) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

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At June 30, 2013, our predominant commodity hedging strategies consisted of (i) hedging anticipated future contracted sales of NGLs, crude oil, and related products associated with volumes held in inventory and (ii) hedging the fair value of natural gas and refined products in inventory. The following information summarizes these hedging strategies:

§ The objective of our NGL, crude oil, and related products sales hedging program is to hedge the margins of anticipated future sales of inventory by locking in sales prices through the use of forward physical sales contracts and commodity derivative instruments.

§ The objective of our natural gas and refined products inventory hedging program is to hedge the fair value of natural gas and refined products currently held in inventory by locking in the sales price of the inventory through the use of commodity derivative instruments.

At June 30, 2013, we did not have any hedges in place with respect to gross margins associated with our future natural gas processing activities. Management continues to evaluate market conditions to determine the appropriate timing to implement this strategy, if at all, during 2013.

Certain basis swaps, basis spread options and other derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of natural gas and crude oil. 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 guidance, these instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of the underlying assets. The earnings volatility caused by fluctuations in non-cash, mark-to-market earnings cannot be predicted.

Tabular Presentation of Fair Value Amounts, 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			
	June 30, 2013		December 31, 2012		June 30, 2013		December 31, 2012	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments								
Interest rate derivatives	Other current assets	$19.8	Other current assets	$19.6	Other current liabilities	$--	Other current liabilities	$175.4
Interest rate derivatives	Other assets	15.7	Other assets	25.6	Other liabilities	--	Other liabilities	--
Total interest rate derivatives		35.5		45.2		--		175.4
Commodity derivatives	Other current assets	42.6	Other current assets	45.3	Other current liabilities	41.6	Other current liabilities	35.4
Commodity derivatives		--		--		--		0.5

	Other assets		Other assets		Other liabilities		Other liabilities	
Total commodity derivatives		42.6		45.3		41.6		35.9
Total derivatives designated as hedging instruments		$78.1		$90.5		$41.6		$211.3
Derivatives not designated as hedging instruments								
Interest rate derivatives	Other current assets	$--	Other current assets	$--	Other current Liabilities	$12.1	Other current liabilities	$12.2
Interest rate derivatives	Other assets	--	Other assets	--	Other liabilities	0.3	Other liabilities	5.0
Total interest rate derivatives		--		--		12.4		17.2
Commodity derivatives	Other current assets	18.0	Other current assets	15.7	Other current liabilities	3.9	Other current liabilities	8.9
Commodity derivatives	Other assets	0.2	Other assets	0.6	Other liabilities	1.4	Other liabilities	0.7
Total commodity derivatives		18.2		16.3		5.3		9.6
Total derivatives not designated as hedging instruments		$18.2		$16.3		$17.7		$26.8

Certain of our commodity derivative instruments are subject to master netting arrangements or similar agreements. The following tables present our derivative instruments subject to such arrangements at the dates indicated:

Offsetting of Financial Assets and Derivative Assets

	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Amounts of Assets Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet: Financial Instruments	Cash Collateral Received	Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)			(v) = (iii) – (iv)
As of June 30, 2013:							
Commodity derivatives	$60.8	$ --	$ 60.8	$(43.2)	$ --	$ (14.3)	$ 3.3
As of December 31, 2012:							
Commodity derivatives	$61.6	$ --	$ 61.6	$(38.7)	$ (15.2)	$ --	$ 7.7

Offsetting of Financial Liabilities and Derivative Liabilities

	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Liabilities Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet: Financial Instruments	Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)		(v) = (iii) – (iv)
As of June 30, 2013:						
Commodity derivatives	$46.9	$ --	$ 46.9	$(43.2)	$ --	$ 3.7
As of December 31, 2012:						
Commodity derivatives	$45.5	$ --	$ 45.5	$(38.7)	$ (4.3)	$ 2.5

Derivative assets and liabilities recorded in our Unaudited Condensed Consolidated Balance Sheets are presented on a gross-basis and determined at the individual transaction level. This presentation method is applied regardless of whether the respective exchange clearing agreements, counterparty contracts or master netting agreements contain netting language often referred to as "rights of offset." Although derivative amounts are presented on a gross-basis, having rights of offset enable the settlement of a net as opposed to gross receivable or payable amount under a counterparty default or liquidation scenario.

Cash is paid and received as collateral under certain agreements, particularly for those associated with exchange transactions. For any cash collateral payments or receipts, corresponding assets or liabilities are recorded to reflect the variation margin deposits or receipts with exchange clearing brokers and customers. These balances are also presented on a gross-basis in our Unaudited Condensed Consolidated Balance Sheets.

The tabular presentation above provides a means for comparing the gross amount of derivative assets and liabilities, excluding associated accounts payable and receivable, to the net amount that would likely be receivable or payable under a default scenario based on the existence of rights of offset in the respective derivative agreements. Any cash collateral paid or received is reflected in this table, but only to the extent that it represents variation margins. Any amounts associated with derivative prepayments or initial margins that are not influenced by the derivative asset or liability amounts or those that are determined solely on their volumetric notional amounts are excluded from this table.

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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 June 30,		For the Six Months Ended June 30,	
		2013	2012	2013	2012
Interest rate derivatives	Interest expense	$(6.6)	$4.6	$(10.1)	$3.1
Commodity derivatives	Revenue	6.9	(16.4)	6.2	(15.7)
Total		$0.3	$(11.8)	$(3.9)	$(12.6)

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2013	2012	2013	2012
Interest rate derivatives	Interest expense	$6.5	$(4.5)	$9.9	$(3.4)
Commodity derivatives	Revenue	(4.9)	15.9	(11.6)	16.3
Total		$1.6	$11.4	$(1.7)	$12.9

With respect to our derivative instruments designated as fair value hedges, amounts attributable to ineffectiveness and those excluded from the assessment of hedge effectiveness were not material to our consolidated financial statements during the periods indicated.

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 June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Interest rate derivatives	$--	$(84.0)	$6.7	$(55.1)
Commodity derivatives – Revenue	34.1	99.8	(13.5)	60.2
Commodity derivatives – Operating costs and expenses	--	5.2	--	(14.8)
Total	$34.1	$21.0	$(6.8)	$(9.7)

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 June 30,		For the Six Months Ended June 30,	
		2013	2012	2013	2012
Interest rate derivatives	Interest expense	$ (7.8)	$ (3.7)	$ (13.7)	$ (6.4)
Commodity derivatives	Revenue	7.2	(2.6)	(0.5)	(12.6)
Commodity derivatives	Operating costs and expenses	--	(11.6)	0.4	(23.6)
Total		$ (0.6)	$ (17.9)	$ (13.8)	$ (42.6)

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion)			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2013	2012	2013	2012
Commodity derivatives	Revenue	$ (0.1)	$ 0.9	$ (0.1)	$ 0.9
Commodity derivatives	Operating costs and expenses	--	--	--	0.3
Total		$ (0.1)	$ 0.9	$ (0.1)	$ 1.2

Over the next twelve months, we expect to reclassify $31.3 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 $3.2 million of losses attributable to commodity derivative instruments from accumulated other comprehensive loss to earnings as a decrease in revenue.

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:

Derivatives Not Designated as Hedging Instruments	Location	Gain (Loss) Recognized in Income on Derivative			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2013	2012	2013	2012
Interest rate derivatives	Interest expense	$(0.2)	$(1.1)	$(0.1)	$(3.3)
Commodity derivatives	Revenue	14.2	9.3	8.9	30.1
Commodity derivatives	Operating costs and expenses	--	--	--	(2.8)
Total		$14.0	$8.2	$8.8	$24.0

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 table sets forth, by level within the fair value hierarchy, the carrying values of our financial assets and liabilities at June 30, 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.

Fair Value Measurements Using
Quoted
Prices

	in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Carrying Value at June 30, 2013
Financial assets:				
Interest rate derivatives	$ --	$ 35.5	$ --	$ 35.5
Commodity derivatives	20.5	40.2	0.1	60.8
Total	$ 20.5	$ 75.7	$ 0.1	$ 96.3
Financial liabilities:				
Interest rate derivatives	$ --	$ 12.4	$ --	$ 12.4
Commodity derivatives	8.9	37.7	0.3	46.9
Total	$ 8.9	$ 50.1	$ 0.3	$ 59.3

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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:

	Location	For the Six Months Ended June 30, 2013	2012
Financial asset (liability) balance, net, January 1		$(1.5)	$0.4
Total gains (losses) included in:			
Net income (1)	Revenue	(0.6)	0.5
Other comprehensive income	Commodity derivative instruments – changes in fair value of cash flow hedges	--	0.5
Settlements	Revenue	1.5	(0.5)
Financial asset (liability) balance, net, March 31		(0.6)	0.9
Total gains (losses) included in:			
Net income (1)	Revenue	(0.2)	(1.3)
Other comprehensive income	Commodity derivative instruments – changes in fair value of cash flow hedges	--	6.0
Settlements	Revenue	0.6	(0.7)
Financial asset (liability) balance, net, June 30 (2)		$(0.2)	$4.9

(1) There were unrealized gains of $0.4 million and $1.3 million included in these amounts for the three and six months ended June 30, 2013, respectively. There were $2.0 million and $1.9 million of unrealized losses included in these amounts for the three and six months ended June 30, 2012, respectively.
(2) There were no transfers into or out of Level 3 during the three or six months ended June 30, 2013.

The following table provides quantitative information about our recurring Level 3 fair value measurements at June 30, 2013:

	Fair Value Financial Assets	Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives – Crude oil	$0.1	$ 0.3	Discounted cash flow	Forward commodity prices	$94.20-$96.63/barrel

We believe forward commodity prices are the most significant unobservable inputs in determining our Level 3 recurring fair value measurements at June 30, 2013. In general, changes in the price of the underlying commodity increases or decreases the fair value of a commodity derivative depending on whether the derivative was purchased or sold. We generally expect changes in the fair value of our derivative instruments to be offset by corresponding changes in the fair value of our hedged exposures.

We have a risk management policy that covers our Level 3 commodity derivatives. Governance and oversight of risk management activities for these commodities are provided by our CEO with guidance and support from a risk management committee ("RMC") that meets quarterly (or on a more frequent basis, if needed). Members of executive management attend the RMC meetings, which are chaired by the head of our commodities risk control group. This group is responsible for preparing and distributing daily reports and risk analysis to members of the RMC and other appropriate members of management. These reports include mark-to-market valuations with the one-day and month-to-date changes in fair values. This group also develops and validates the forward commodity price curves used to estimate the fair values of our Level 3 commodity derivatives. These forward curves incorporate published indexes, market quotes and other observable inputs to the extent available.

Nonrecurring Fair Value Measurements

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
NGL Pipelines & Services	$8.7	$2.9	$9.7	$8.0
Onshore Crude Oil Pipelines & Services	16.6	6.2	16.6	6.2
Petrochemical & Refined Products Services	1.8	--	11.8	0.3
Total	$27.1	$9.1	$38.1	$14.5

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

During the six months ended June 30, 2013, we recorded $38.1 million of non-cash asset impairment charges primarily due to the abandonment of assets classified as property, plant and equipment. Of this amount, $16.6 million relates to the abandonment of certain crude oil pipeline segments in Texas and Oklahoma, $10.0 million relates to the abandonment of certain refined products terminal and storage assets located in southeast Texas, and $6.3 million relates to the abandonment of an NGL storage cavern in Arizona. The following table summarizes our non-recurring fair value measurements for the six months ended June 30, 2013:

		Fair Value Measurements Using			
	Carrying Value at June 30, 2013	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Impairment of long-lived assets disposed of other than by sale	$ --	$--	$ --	$ --	$ 29.8
Impairment of long-lived assets held and used	6.3	--	--	6.3	4.2
Impairment of long-lived assets to be disposed of by sale	34.6	33.8	--	0.8	4.1
Total	$ 40.9				$ 38.1

During the six months ended June 30, 2012, we recorded $14.5 million of non-cash asset impairment charges primarily due to the abandonment of assets classified as property, plant and equipment. Of this amount, $6.2 million relates to the abandonment of certain crude oil pipeline segments in Texas and Oklahoma, $4.6 million relates to the abandonment of an NGL fractionator in South Texas, and $2.9 million relates to abandonment of certain segments of the Tri-States pipeline. The following table summarizes our non-recurring fair value measurements for the six months ended June 30, 2012:

		Fair Value Measurements Using			
	Carrying Value at June 30, 2012	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Impairment of long-lived assets disposed of other than by sale	$ --	$ --	$ --	$ --	$ 14.2
Impairment of long-lived assets to be disposed of by sale	--	--	--	--	0.3
Total	$ --				$ 14.5

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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 long-term fixed-rate debt obligations was $17.98 billion and $18.42 billion at June 30, 2013 and December 31, 2012, respectively. The aggregate carrying value of these debt obligations was $16.88 billion and $16.18 billion at June 30, 2013 and December 31, 2012, respectively. These values are based on quoted market prices for such debt or debt of similar terms and maturities (Level 2), our credit standing and the credit standing of our counterparties. Changes in market rates of interest affect the fair value of our fixed-rate debt. The carrying values of our variable-rate long-term debt obligations approximate their fair values since the associated interest rates are market-based. We do not have any long-term investments in debt or equity securities recorded at fair value.

Note 5. Inventories

Our available-for-sale inventory amounts by product type were as follows at the dates indicated:

	June 30, 2013	December 31, 2012
NGLs	$799.1	$ 594.3
Petrochemicals and refined products	394.0	304.5
Crude oil	156.9	119.4
Natural gas	61.4	70.2
Total	$1,411.4	$ 1,088.4

In those instances where we take ownership of inventory volumes through percent-of-liquids contracts and similar arrangements (as opposed to outright purchases from third parties for cash), these volumes are valued at market-based prices during the month in which they are acquired.

Due to fluctuating commodity prices, we recognize lower of cost or market adjustments when the carrying value of our available-for-sale inventories exceeds their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized. To the extent our commodity hedging strategies address inventory-related price risks and are successful, these inventory valuation adjustments are mitigated or offset. See Note 4 for a description of our commodity hedging activities.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Cost of sales (1)	$9,458.3	$8,195.2	$19,150.8	$17,861.0
Lower of cost or market adjustments	7.7	8.0	10.4	13.9

(1) Cost of sales is a component of "Operating costs and expenses," as presented on our Unaudited Condensed Statements of Consolidated Operations.

Period-to-period fluctuations in these amounts are primarily due to changes in energy commodity prices and sales volumes associated with our marketing activities.

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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	June 30, 2013	December 31, 2012
Plants, pipelines and facilities (1)	3-45 (6)	$26,455.2	$25,382.4
Underground and other storage facilities (2)	5-40 (7)	1,895.8	1,826.3
Platforms and facilities (3)	20-31	664.8	635.2
Transportation equipment (4)	3-10	132.1	136.2
Marine vessels (5)	15-30	713.3	695.0
Land		179.0	167.2
Construction in progress		2,104.7	2,113.1
Total		32,144.9	30,955.4
Less accumulated depreciation		6,578.8	6,109.0
Property, plant and equipment, net		$25,566.1	$24,846.4

(1) Plants and pipelines include processing plants; NGL, natural gas, crude oil and petrochemical and refined products pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment and related assets.
(2) Underground and other storage facilities include underground product storage caverns; above ground storage tanks; water wells and related assets.
(3) Platforms and facilities include offshore platforms and related facilities and other associated assets located in the Gulf of Mexico.
(4) Transportation equipment includes tractor-trailer tank trucks and other vehicles and similar assets used in our operations.
(5) Marine vessels include tow boats, barges and related equipment used in our marine transportation business.
(6) In general, the estimated useful lives of major assets within this category are: processing plants, 20-35 years; pipelines and related equipment, 5-45 years; terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings, 20-40 years; and laboratory and shop equipment, 5-35 years.
(7) In general, the estimated useful lives of assets within this category are: underground storage facilities, 5-35 years; storage tanks, 10-40 years; and water wells, 5-35 years.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Depreciation expense (1)	$250.8	$222.0	$496.2	$434.0

Capitalized interest (2)	35.7	29.5	67.3	60.1

(1) Depreciation expense is a component of "Costs and expenses" as presented on our Unaudited Condensed Statements of Consolidated Operations.

(2) We capitalize interest cost incurred on funds used to construct property, plant and equipment. 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 January 2013, we sold certain trucking assets for cash proceeds of $29.5 million. As a result of this transaction, net income for the six months ended June 30, 2013 includes a $0.5 million loss from the sale of these assets.

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 six months ended June 30, 2013 includes a $52.5 million gain from the sale of these assets. The Seminole Pipeline remains connected to our Mont Belvieu complex through a newly constructed NGL pipeline that we own.

In April 2013, we sold certain lubrication oil and specialty chemical distribution assets for cash proceeds of $35.3 million. As a result, net income for the three and six months ended June 30, 2013 includes a $6.7 million gain from the sale of these assets.

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We received cash proceeds of $14.3 million and $14.9 million from the sale of certain marine transportation assets during the three and six months ended June 30, 2013, respectively. As a result of these transactions, net income for the three and six months ended June 30, 2013 includes a $6.7 million loss from the sale of these assets.

Asset Retirement Obligations

Property, plant and equipment at June 30, 2013 and December 31, 2012 includes $40.9 million and $40.3 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

The following table presents information regarding our asset retirement obligations ("AROs") during the six months ended June 30, 2013:

ARO liability balance, December 31, 2012	$105.2
Liabilities incurred	0.1
Liabilities settled	(6.8)
Revisions in estimated cash flows	2.9
Accretion expense	3.1
ARO liability balance, June 30, 2013	$104.5

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

Remainder of 2013	2014	2015	2016	2017
$ 3.1	$6.5	$6.3	$6.6	$7.1

Certain of our unconsolidated affiliates have AROs recorded at June 30, 2013 and December 31, 2012 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our consolidated financial statements.

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Note 7. Investments in Unconsolidated Affiliates

The following table presents our investments in unconsolidated affiliates by business segment at the dates indicated. Unless noted otherwise, we account for these investments using the equity method.

	Ownership Interest at June 30, 2013	June 30, 2013	December 31, 2012
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$30.6	$ 29.6
K/D/S Promix, L.L.C.	50%	45.2	46.9
Baton Rouge Fractionators LLC	32.2%	19.4	20.2
Skelly-Belvieu Pipeline Company, L.L.C.	50%	40.3	38.2
Texas Express Pipeline LLC	35%	282.7	144.4
Texas Express Gathering LLC	45%	29.2	20.9
Front Range Pipeline LLC	33.3%	68.1	24.4
Onshore Natural Gas Pipelines & Services:			
White River Hub, LLC	50%	24.4	24.9
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC	50%	558.1	341.4
Eagle Ford Pipeline LLC	50%	225.0	152.4
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36%	45.4	47.3
Cameron Highway Oil Pipeline Company	50%	211.1	220.0
Deepwater Gateway, L.L.C.	50%	87.2	90.0
Neptune Pipeline Company, L.L.C.	25.7%	44.6	46.8
Southeast Keathley Canyon Pipeline Company L.L.C.	50%	155.0	74.9
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	8.0	8.5
Centennial Pipeline LLC ("Centennial")	50%	61.5	60.8
Other (1)	Various	3.0	3.0
Total		$1,938.8	$ 1,394.6

(1) Other unconsolidated affiliates include a 50% interest in a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas and a 25% interest in a company that provides logistics communications solutions between petroleum pipelines and their customers.

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

For the Three	For the Six Months

	Months Ended June 30,		Ended June 30,	
	2013	2012	2013	2012
NGL Pipelines & Services	$3.8	$3.8	$7.7	$9.0
Onshore Natural Gas Pipelines & Services	0.9	1.2	1.9	2.6
Onshore Crude Oil Pipelines & Services	30.1	3.6	66.7	4.1
Offshore Pipelines & Services	8.7	4.1	15.1	11.0