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 September 30, 2012

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 ☑ 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 ☑ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

There were 895,642,295 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 October 31, 2012. 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.
	PART I. FINANCIAL INFORMATION.	
Item 1.	**Financial Statements.**	
	Unaudited Condensed Consolidated Balance Sheets	2
	Unaudited Condensed Statements of Consolidated Operations	3
	Unaudited Condensed Statements of Consolidated Comprehensive Income	4
	Unaudited Condensed Statements of Consolidated Cash Flows	5
	Unaudited Condensed Statements of Consolidated Equity	6
	Notes to Unaudited Condensed Consolidated Financial Statements:	
	1. Partnership Operations, Organization and Basis of Presentation	7
	2. General Accounting Matters	8
	3. Equity-based Awards	11
	4. Derivative Instruments, Hedging Activities and Fair Value Measurements	13
	5. Inventories	21
	6. Property, Plant and Equipment	22
	7. Investments in Unconsolidated Affiliates	24
	8. Intangible Assets and Goodwill	28
	9. Debt Obligations	29
	10. Equity and Distributions	31
	11. Business Segments	34
	12. Related Party Transactions	38
	13. Earnings Per Unit	39
	14. Commitments and Contingencies	40
	15. Supplemental Cash Flow Information	41
	16. Insurance Matters	42
	17. Condensed Consolidating Financial Information	44
Item 2.	**Management's Discussion and Analysis of Financial Condition and Results of Operations.**	51
Item 3.	**Quantitative and Qualitative Disclosures about Market Risk.**	73
Item 4.	**Controls and Procedures.**	76
	PART II. OTHER INFORMATION.	
Item 1.	**Legal Proceedings.**	77
Item 1A.	**Risk Factors.**	77
Item 2.	**Unregistered Sales of Equity Securities and Use of Proceeds.**	77
Item 3.	**Defaults Upon Senior Securities.**	77
Item 4.	**Mine Safety Disclosures.**	77
Item 5.	**Other Information.**	77
Item 6.	**Exhibits.**	78
Signatures		85

PART I. FINANCIAL INFORMATION.

Item 1. *Financial Statements.*

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

ASSETS	September 30, 2012	December 31, 2011
Current assets:		
Cash and cash equivalents	$ 14.5	$ 19.8
Restricted cash	18.8	38.5
Accounts receivable – trade, net of allowance for doubtful accounts of $13.2 at September 30, 2012 and $13.4 at December 31, 2011	4,389.4	4,501.8
Accounts receivable – related parties	10.4	43.5
Inventories	1,069.2	1,111.7
Prepaid and other current assets	390.8	353.4
Total current assets	5,893.1	6,068.7
Property, plant and equipment, net	24,311.5	22,191.6
Investments in unconsolidated affiliates	1,160.4	1,859.6
Intangible assets, net of accumulated amortization of $1,022.4 at September 30, 2012 and $990.4 at December 31, 2011	1,596.1	1,656.2
Goodwill	2,092.3	2,092.3
Other assets	224.4	256.7
Total assets	$ 35,277.8	$ 34,125.1
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt	$ 1,200.0	$ 500.0
Accounts payable – trade	798.6	773.0
Accounts payable – related parties	112.6	211.6
Accrued product payables	4,318.5	5,047.1
Accrued interest	188.2	288.1
Other current liabilities	617.9	612.6
Total current liabilities	7,235.8	7,432.4
Long-term debt (see Note 9)	14,747.2	14,029.4
Deferred tax liabilities	20.8	91.2
Other long-term liabilities	216.1	352.8
Commitments and contingencies (see Note 14)		
Equity: (see Note 10)		
Partners' equity:		
Limited partners:		
Common units (895,643,795 units outstanding at September 30, 2012 and 881,620,418 units outstanding at December 31, 2011)	13,219.4	12,346.3
Class B units (4,520,431 units outstanding at September 30, 2012 and December 31, 2011)	118.5	118.5
Accumulated other comprehensive loss	(388.3)	(351.4)
Total partners' equity	12,949.6	12,113.4
Noncontrolling interests	108.3	105.9
Total equity	13,057.9	12,219.3
Total liabilities and equity	$ 35,277.8	$ 34,125.1

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Revenues:				
Third parties	$ 10,461.2	$ 11,163.2	$ 31,447.1	$ 32,169.1
Related parties	7.5	163.9	63.9	558.2
Total revenues (see Note 11)	10,468.7	11,327.1	31,511.0	32,727.3
Costs and expenses:				
Operating costs and expenses:				
Third parties	9,456.6	10,146.2	28,563.4	29,398.3
Related parties	203.2	458.4	573.1	1,276.7
Total operating costs and expenses	9,659.8	10,604.6	29,136.5	30,675.0
General and administrative costs:				
Third parties	18.8	20.0	59.1	49.2
Related parties	22.6	30.0	71.1	89.1
Total general and administrative costs	41.4	50.0	130.2	138.3
Total costs and expenses (see Note 11)	9,701.2	10,654.6	29,266.7	30,813.3
Equity in income of unconsolidated affiliates	21.0	8.6	42.2	35.9
Operating income	788.5	681.1	2,286.5	1,949.9
Other income (expense):				
Interest expense	(199.7)	(189.0)	(572.8)	(561.1)
Interest income	0.3	0.3	0.7	0.9
Other, net (see Note 2)	1.2	(1.3)	72.7	(1.1)
Total other expense, net	(198.2)	(190.0)	(499.4)	(561.3)
Income before income taxes	590.3	491.1	1,787.1	1,388.6
Benefit from (provision for) income taxes (see Note 2)	(2.4)	(11.6)	23.5	(26.1)
Net income	587.9	479.5	1,810.6	1,362.5
Net income attributable to noncontrolling interests (see Note 10)	(1.1)	(8.1)	(6.2)	(36.7)
Net income attributable to limited partners	$ 586.8	$ 471.4	$ 1,804.4	$ 1,325.8
Earnings per unit: (see Note 13)				
Basic earnings per unit	$ 0.68	$ 0.57	$ 2.10	$ 1.62
Diluted earnings per unit	$ 0.66	$ 0.55	$ 2.03	$ 1.55

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Net income	$ 587.9	$ 479.5	$ 1,810.6	$ 1,362.5
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instruments:				
Changes in fair value of cash flow hedges	(58.5)	(6.1)	(13.1)	(179.2)
Reclassification of gains and losses to net income	0.9	35.1	37.1	178.8
Interest rate derivative instruments:				
Changes in fair value of cash flow hedges	(20.2)	(260.1)	(75.3)	(306.1)
Reclassification of gains and losses to net income	4.5	1.6	10.9	4.6
Total cash flow hedges	(73.3)	(229.5)	(40.4)	(301.9)
Change in funded status of pension and postretirement plans, net of tax	3.7	--	2.5	(0.6)
Proportionate share of other comprehensive income (loss) of unconsolidated affiliate	--	--	1.0	(0.7)
Total other comprehensive loss	(69.6)	(229.5)	(36.9)	(303.2)
Comprehensive income	518.3	250.0	1,773.7	1,059.3
Comprehensive income attributable to noncontrolling interests	(1.1)	(8.1)	(6.2)	(36.7)
Comprehensive income attributable to limited partners	$ 517.2	$ 241.9	$ 1,767.5	$ 1,022.6

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Nine Months Ended September 30, 2012	2011
Operating activities:		
Net income	$ 1,810.6	$ 1,362.5
Reconciliation of net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	817.9	739.2
Non-cash asset impairment charges	57.6	5.2
Equity in income of unconsolidated affiliates	(42.2)	(35.9)
Distributions received from unconsolidated affiliates	67.5	122.5
Gains related to asset sales (see Note 15)	(4.1)	(0.6)
Gains related to property damage insurance recoveries (see Note 16)	(30.0)	--
Gains related to sales of Energy Transfer Equity common units (see Note 7)	(68.8)	(24.8)
Deferred income tax expense (benefit)	(67.9)	5.5
Changes in fair market value of derivative instruments	(15.9)	(6.8)
Net effect of changes in operating accounts (see Note 15)	(910.2)	61.6
Other operating activities	1.3	(0.2)
Net cash flows provided by operating activities	1,615.8	2,228.2
Investing activities:		
Capital expenditures	(2,716.1)	(2,792.2)
Contributions in aid of construction costs	18.2	12.3
Decrease in restricted cash	19.7	20.1
Investments in unconsolidated affiliates	(351.8)	(11.9)
Proceeds from asset sales (see Note 15)	1,137.4	440.5
Proceeds from property damage insurance recoveries (see Note 16)	30.0	--
Other investing activities	(32.4)	(7.4)
Cash used in investing activities	(1,895.0)	(2,338.6)
Financing activities:		
Borrowings under debt agreements	7,141.4	6,565.1
Repayments of debt	(5,716.0)	(4,989.3)
Debt issuance costs	(20.7)	(33.9)
Monetization of interest rate derivative instruments (see Note 4)	(147.8)	(23.2)
Cash distributions paid to limited partners (see Note 10)	(1,613.4)	(1,459.7)
Cash distributions paid to noncontrolling interests (see Note 10)	(11.3)	(52.0)
Cash contributions from noncontrolling interests (see Note 10)	6.5	4.7
Net cash proceeds from issuance of common units	654.8	67.1
Other financing activities	(19.6)	(4.8)
Cash provided by financing activities	273.9	74.0
Net change in cash and cash equivalents	(5.3)	(36.4)
Cash and cash equivalents, January 1	19.8	65.5
Cash and cash equivalents, September 30	$ 14.5	$ 29.1

See Notes to Unaudited Condensed Consolidated Financial Statements.

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, 2011	$ 12,464.8	$ (351.4)	$ 105.9	$ 12,219.3
Net income	1,804.4	--	6.2	1,810.6
Cash distributions paid to limited partners	(1,613.4)	--	--	(1,613.4)
Cash distributions paid to noncontrolling interests	--	--	(11.3)	(11.3)
Cash contributions from noncontrolling interests	--	--	6.5	6.5
Net cash proceeds from issuance of common units	654.8	--	--	654.8
Amortization of fair value of equity-based awards	45.9	--	--	45.9
Cash flow hedges	--	(40.4)	--	(40.4)
Other	(18.6)	3.5	1.0	(14.1)
Balance, September 30, 2012	$ 13,337.9	$ (388.3)	$ 108.3	$ 13,057.9

	Partners' Equity			
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance, December 31, 2010	$ 11,406.7	$ (32.5)	$ 526.6	$ 11,900.8
Net income	1,325.8	--	36.7	1,362.5
Cash distributions paid to limited partners	(1,459.7)	--	--	(1,459.7)
Cash distributions paid to noncontrolling interests	--	--	(52.0)	(52.0)
Cash contributions from noncontrolling interests	--	--	4.7	4.7
Net cash proceeds from issuance of common units	67.1	--	--	67.1
Amortization of fair value of equity-based awards	37.9	--	0.1	38.0
Issuance of common units pursuant to Duncan Merger (see Note 1)	402.8	(1.1)	(401.7)	--
Cash flow hedges	--	(301.9)	--	(301.9)
Other	(5.1)	(1.3)	(1.6)	(8.0)
Balance, September 30, 2011	$ 11,775.5	$ (336.8)	$ 112.8	$ 11,551.5

See Notes to Unaudited Condensed Consolidated Financial Statements.

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 footnote disclosure, the dollar amounts presented in the tabular data within these footnote 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 of Enterprise GP; (ii) Dr. Ralph S. Cunningham, who is also a director and the Chairman of Enterprise GP; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP. Each of the DD LLC Trustees also currently serves as one of the three managers of Dan Duncan LLC.

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

In April 2011, we, our general partner, EPD MergerCo LLC ("Duncan MergerCo," our wholly owned subsidiary), Duncan Energy Partners L.P. ("Duncan Energy Partners") and DEP Holdings, LLC ("DEP GP," the general partner of Duncan Energy Partners) entered into a definitive merger agreement (the "Duncan Merger Agreement"). In September 2011, the Duncan Merger Agreement was approved by the unitholders of Duncan Energy Partners and the merger of Duncan MergerCo with and into Duncan Energy Partners and related transactions were completed, with Duncan Energy Partners surviving such merger as our wholly owned subsidiary (collectively, we refer to these transactions as the "Duncan Merger"). See Note 1 for additional information regarding the Duncan Merger.

References to "Holdings Merger" mean the merger of Enterprise GP Holdings L.P. with and into a wholly owned subsidiary of ours, with our subsidiary surviving such merger. The Holdings Merger and related transactions were completed in November 2010.

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

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries. We sold the remainder of our limited partner interests in Energy Transfer Equity in April 2012 (see Note 7).

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 midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States ("U.S."), Canada and the Gulf of Mexico with domestic consumers and international markets. Our assets include approximately 50,700 miles of onshore and offshore pipelines; 190 million barrels ("MMBbls") of storage capacity for NGLs, crude oil, refined products and petrochemicals; and 14 billion cubic feet ("Bcf") of natural gas storage capacity.

Our integrated midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals; crude oil and refined products transportation, storage, and terminals; offshore production platforms; petrochemical transportation and services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico.

We have 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 (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.

Completion of Duncan Merger

On September 7, 2011, the Duncan Merger Agreement was approved by the unitholders of Duncan Energy Partners and the merger of Duncan MergerCo and Duncan Energy Partners and related transactions were completed, with Duncan Energy Partners surviving such merger as our wholly owned subsidiary. Each issued and outstanding common unit of Duncan Energy Partners was cancelled and converted into the right to receive common units representing limited partner interests in Enterprise based on an exchange ratio of 1.01 Enterprise common units for each Duncan Energy Partners common unit. Enterprise issued 24,277,310 of its common units (net of fractional common units cashed out) as consideration in the Duncan Merger. No Enterprise common units were issued to Enterprise or its subsidiaries as merger consideration. Since we historically consolidated Duncan Energy Partners for financial reporting purposes, the Duncan Merger did not change the basis of presentation of our historical financial statements.

Note 2. General Accounting Matters

Our results of operations for the three and nine months ended September 30, 2012 are not necessarily indicative of results expected for the full year of 2012. 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").

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

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, 2011 (the "2011 Form 10-K") filed with the SEC on February 29, 2012.

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 transactions. To qualify for hedge accounting, the hedged item must expose us to risk and the related derivative instrument must reduce that exposure 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 or quarterly 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 of our 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 the 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.

See Note 4 for additional information regarding our derivative instruments and related interest rate and commodity hedging activities.

Estimates

Preparing our consolidated financial statements in conformity with 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.

Income Tax Benefit

For the nine months ended September 30, 2012, we recognized a net income tax benefit of $23.5 million, which was primarily due to a $46.5 million net income tax benefit related to the conversion of certain of our subsidiaries to limited liability companies during the first quarter of 2012, partially offset by accruals for the Texas Margin Tax. The $46.5 million net income tax benefit is attributable to the difference between deferred income taxes accrued by the applicable subsidiaries through the date of conversion and any current income tax due in connection with the conversions.

Other Non-Operating Income

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Gain on sales of available-for-sale equity securities of Energy Transfer Equity (1)	$ --	$ --	$ 68.8	$ --
Distribution income from Energy Transfer Equity	--	--	4.1	--
Other	1.2	(1.3)	(0.2)	(1.1)
Total	$ 1.2	$ (1.3)	$ 72.7	$ (1.1)

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

Recent Accounting Developments

Accounting standard setting organizations have been very active in recent years. Recently, they issued new and revised accounting guidance on a number of topics, including disclosures related to offsetting assets and liabilities. We do not believe that adoption of this new guidance will have a material impact on our consolidated financial statements.

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

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 expense we recognized in connection with equity-based awards for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Restricted common unit awards	$ 13.8	$ 11.9	$ 44.3	$ 35.4
Unit option awards	0.2	0.7	1.2	2.4
Other (1)	0.2	0.2	1.6	--
Total compensation expense	$ 14.2	$ 12.8	$ 47.1	$ 37.8

(1) Primarily consists of 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 period. Liability-classified awards are settled in cash upon vesting.

At September 30, 2012, 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"). In addition, there were unvested awards outstanding under an inactive plan, the Enterprise Products 2006 TPP Long-Term Incentive Plan ("2006 Plan"). After giving effect to awards granted under the 1998 Plan and 2008 Plan through September 30, 2012, a total of 842,359 and 5,180,780 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 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. Such awards are non-vested until the required service period expires. Restricted common unit awards issued in 2012 generally vest at a rate of 25% per year beginning one year after the grant date. 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 presented:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted common units at December 31, 2011	3,868,216	$ 34.22
Granted (2,3)	1,556,038	$ 51.94
Vested (3)	(1,264,483)	$ 34.76
Forfeited	(225,390)	$ 40.05
Restricted common units at September 30, 2012	3,934,381	$ 40.72

(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 in 2012 was $80.8 million based on a grant date market price ranging from $51.92 to $53.54 per unit. An estimated annual forfeiture rate of 3.25% 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 2012. A total of 10,038 restricted common units were issued in February 2012 to the independent directors of Enterprise GP that 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 our restricted common unit awards for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Cash distributions paid to restricted common unit holders	$ 2.5	$ 2.4	$ 7.9	$ 7.2
Total intrinsic value of our restricted common unit awards that vested during period	1.5	2.3	64.2	37.5

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate $73.0 million at September 30, 2012, of which our allocated share of the cost is currently estimated to be $69.3 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 1.9 years.

Unit Option Awards

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options. These unit option awards are denominated in our common units. When issued, the exercise price of each unit option award may be no less than the market price of our common units on the date of grant. In general, unit option awards have a vesting period of four years from the date of grant and expire at the end of the calendar year following the year of vesting (e.g., an option vesting on May 29, 2011 will expire on December 31, 2012). 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 are 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 presented:

	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, 2011	3,753,420	$ 28.08	2.6	$ 11.1
Exercised	(712,280)	$ 30.76		
Forfeited	(250,000)	$ 27.45		
Unit option awards at September 30, 2012	2,791,140	$ 27.45	2.2	$ 16.1
Options exercisable at September 30, 2012	--		--	--

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

In order to fund its unit option-related obligations, EPCO may purchase common units at fair value either in the open market or directly from us. When employees exercise unit options, we reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

The following table presents supplemental information regarding our unit option awards during the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Total intrinsic value of unit option awards exercised during period	$ --	$ --	$ 14.0	$ --
Cash received from EPCO in connection with the exercise of unit option awards	--	--	10.2	--
Unit option-related reimbursements to EPCO	--	--	14.0	--

For the EPCO group of companies, the unrecognized compensation cost associated with unit option awards was an aggregate $1.5 million at September 30, 2012, of which our allocated share of the cost is currently estimated to be $1.4 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 0.9 years.

Unit Appreciation Rights

At December 31, 2011, there were 107,328 UARs outstanding that had been granted under the 2006 Plan. The accrued liability for UARs at December 31, 2011 was $0.5 million. All of these awards vested in May 2012. The accrued liability for UARs in May 2012 (i.e., immediately before vesting) was $1.4 million. While these awards were outstanding, they were accounted for as liability awards.

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 certain anticipated future transactions, we use derivative instruments. 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 balance sheet 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. 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. 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. The following table summarizes our portfolio of interest rate swaps at September 30, 2012:

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 1.4%	Fair value hedge
Undesignated swaps	6 floating-to-fixed swaps	$ 600.0	5/2010 to 7/2014	0.5% 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. As fair value hedges, the unamortized portion of these gains are a component of long-term debt (see Note 9) and are being amortized to earnings (as a decrease in interest expense) using the effective interest method over the forecasted hedged period of approximately three years.

The following table summarizes our portfolio of forward starting swaps outstanding at September 30, 2012. Forward starting swaps hedge the expected underlying benchmark interest rates related to future issuances of debt.

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Future debt offering	16 forward starting swaps	$ 1,000.0	3/2013	3.7%	Cash flow hedge

In connection with the issuance of Senior Notes EE in February 2012 (see Note 9), we settled ten forward starting swaps having an aggregate notional amount of $500.0 million, resulting in cash losses totaling $115.3 million. These losses are reflected in accumulated other comprehensive loss and are being amortized to earnings (as an increase in interest expense) over the forecasted hedge period of ten years using the effective interest method.

In connection with EPO's issuance of Senior Notes FF and Senior Notes GG in August 2012 (see Note 9), we settled seven forward starting swaps having an aggregate notional amount of $350.0 million, resulting in cash losses of $70.2 million. These losses are reflected in accumulated other comprehensive loss and will be amortized to earnings (as an increase in interest expense) over the forecasted hedged period of ten years using the effective interest method.

Although we incurred cash losses upon settlement of our forward starting swaps in February 2012 and August 2012, we benefited from the exceptionally low interest rate environment during these periods relative to the interest rates in effect at the time we entered into the swaps.

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 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 options contracts. The following table summarizes our commodity derivative instruments outstanding at September 30, 2012 (volume measures as noted):

Derivative Purpose	Volume (1) Current (2)	Volume (1) Long-Term (2)	Accounting Treatment
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction ("PTR") (Bcf) (3)	7.2	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls) (4)	0.8	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	0.4	0.4	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	2.3	0.5	Cash flow hedge
Natural gas marketing:			
Forecasted sales of natural gas (Bcf)	3.1	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	14.5	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	1.5	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	4.4	0.1	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.4	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	0.8	n/a	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	4.3	0.4	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	6.2	0.9	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (5,6)	164.2	34.5	Mark-to-market
Refined products risk management activities (MMBbls) (6)	1.1	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (6)	5.1	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is December 2013, March 2013 and October 2015, respectively.
(3) PTR represents the British thermal unit ("Btu") equivalent of the NGLs extracted from natural gas by a processing plant, and includes the natural gas used as plant fuel to extract those liquids, plant flare and other shortages.
(4) Forecasted sales of NGL volumes under natural gas processing exclude 1.0 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.
(5) Current volumes include 49.3 Bcf of physical derivative instruments that are predominantly priced at an index plus a premium or minus a discount related to location differences.
(6) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

Our predominant commodity hedging strategies are: (i) hedging natural gas processing margins; (ii) hedging anticipated future contracted sales of NGLs, refined products and crude oil associated with volumes held in inventory; and (iii) hedging the fair value of natural gas in inventory. The following information summarizes these hedging strategies:

§ The objective of our natural gas processing strategy is to hedge an amount of gross margin associated with our natural gas processing activities. We achieve this objective by using physical and financial instruments to lock in the purchase prices of natural gas consumed as PTR and the sales prices of the related NGL products. This program consists of (i) the forward sale of a portion of our expected equity NGL production at fixed prices through December 2012, which is achieved through the use of forward physical sales contracts and commodity derivative instruments and (ii) the purchase of commodity derivative instruments having a notional amount based on the volume of natural gas expected to be consumed as PTR in the production of such equity NGL production.

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

§ 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.

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			
	September 30, 2012		December 31, 2011		September 30, 2012		December 31, 2011	
	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	$ 16.0	Other current assets	$ 43.7	Other current liabilities	$ 180.5	Other current liabilities	$
Interest rate derivatives	Other assets	29.1	Other assets	44.2	Other liabilities	--	Other liabilities	
Total interest rate derivatives		45.1		87.9		180.5		
Commodity derivatives	Other current assets	59.5	Other current assets	20.3	Other current liabilities	57.1	Other current liabilities	
Commodity derivatives	Other assets	5.3	Other assets	--	Other liabilities	3.5	Other liabilities	
Total commodity derivatives		64.8		20.3		60.6		
Total derivatives designated as hedging instruments		$ 109.9		$ 108.2		$ 241.1		$
Derivatives not designated as hedging instruments								
Interest rate derivatives	Other current assets	$ --	Other current assets	$ --	Other current liabilities	$ 12.0	Other current liabilities	$
Interest rate derivatives	Other assets	--	Other assets	--	Other liabilities	7.5	Other liabilities	
Total interest rate derivatives		--		--		19.5		
Commodity derivatives	Other current assets	12.8	Other current assets	34.4	Other current liabilities	15.7	Other current liabilities	
Commodity derivatives	Other assets	2.1	Other assets	12.6	Other liabilities	1.4	Other liabilities	
Total commodity derivatives		14.9		47.0		17.1		
Total derivatives not designated as hedging instruments		$ 14.9		$ 47.0		$ 36.6		$

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 presented:

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2012	2011	2012	2011
Interest rate derivatives	Interest expense	$ 3.0	$ 23.6	$ 6.1	$ 32.4
Commodity derivatives	Revenue	(0.4)	8.6	(16.1)	7.3
Total		$ 2.6	$ 32.2	$ (10.0)	$ 39.7

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

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Hedged Item			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2012	2011	2012	2011
Interest rate derivatives	Interest expense	$ (2.9)	$ (22.5)	$ (6.3)	$ (32.2)
Commodity derivatives	Revenue	(1.8)	(7.7)	14.5	(8.8)
Total		$ (4.7)	$ (30.2)	$ 8.2	$ (41.0)

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 presented:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income/(Loss) on Derivative (Effective Portion)			
	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Interest rate derivatives	$ (20.2)	$ (260.1)	$ (75.3)	$ (306.1)
Commodity derivatives – Revenue	(59.5)	8.8	0.7	(166.0)
Commodity derivatives – Operating costs and expenses	1.0	(14.9)	(13.8)	(13.2)
Total	$ (78.7)	$ (266.2)	$ (88.4)	$ (485.3)

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 September 30,		For the Nine Months Ended September 30,	
		2012	2011	2012	2011
Interest rate derivatives	Interest expense	$ (4.5)	$ (1.6)	$ (10.9)	$ (4.6)
Commodity derivatives	Revenue	0.3	(33.2)	(12.3)	(181.7)
Commodity derivatives	Operating costs and expenses	(1.2)	(1.9)	(24.8)	2.9
Total		$ (5.4)	$ (36.7)	$ (48.0)	$ (183.4)

Derivatives in Cash Flow Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2012	2011	2012	2011
Commodity derivatives	Revenue	$ (1.1)	$ --	$ (0.2)	$ 0.2
Commodity derivatives	Operating costs and expenses	0.1	(0.9)	0.4	(0.9)
Total		$ (1.0)	$ (0.9)	$ 0.2	$ (0.7)

Over the next twelve months, we expect to reclassify $30.0 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 $0.9 million of gains attributable to commodity derivative instruments from accumulated other comprehensive income to earnings, $0.1 million as an increase in revenue and $0.8 million as a decrease in operating costs and expenses.

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

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 presented:

Derivatives Not Designated as Hedging Instruments	Location	Gain/(Loss) Recognized in Income on Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2012	2011	2012	2011
Interest rate derivatives	Interest expense	$ (2.2)	$ (8.8)	$ (5.5)	$ (19.3)
Commodity derivatives	Revenue	(3.9)	4.3	26.2	17.6
Commodity derivatives	Operating costs and expenses	--	--	(2.8)	--
Foreign currency derivatives	Other income	--	0.2	--	0.2
Total		$ (6.1)	$ (4.3)	$ 17.9	$ (1.5)

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 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 September 30, 2012. These assets and liabilities are measured on a recurring basis and are classified based on the lowest level of input that is significant to their respective 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 September 30, 2012
Financial assets:				
Interest rate derivatives	$ --	$ 45.1	$ --	$ 45.1
Commodity derivatives	22.4	44.0	13.3	79.7
Total	$ 22.4	$ 89.1	$ 13.3	$ 124.8
Financial liabilities:				
Interest rate derivatives	$ --	$ 200.0	$ --	$ 200.0
Commodity derivatives	32.5	41.1	4.1	77.7
Total	$ 32.5	$ 241.1	$ 4.1	$ 277.7

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

	Location	For the Nine Months Ended September 30, 2012	2011
Balance, January 1		$ 0.4	$ (25.9)
Total gains (losses) included in:			
Net income (1)	Revenue	0.5	(0.5)
Other comprehensive income (loss)	Commodity derivative instruments – changes in fair value of cash flow hedges	0.5	16.2
Settlements		(0.5)	0.8
Transfers out of Level 3 (2)		--	9.8
Balance, March 31		0.9	0.4
Total gains (losses) included in:			
Net income (1)	Revenue	(1.3)	1.9
Other comprehensive income (loss)	Commodity derivative instruments – changes in fair value of cash flow hedges	6.0	--
Settlements		(0.7)	(0.2)
Balance, June 30		4.9	2.1
Total gains (losses) included in:			
Net income (1)	Revenue	(0.6)	0.8
Other comprehensive income (loss)	Commodity derivative instruments – changes in fair value of cash flow hedges	3.5	--
Settlements		1.4	(2.2)
Balance, September 30		$ 9.2	$ 0.7

(1) There were $0.8 million of unrealized gains and $1.1 million of unrealized losses included in these amounts for the three and nine months ended September 30, 2012, respectively. There were $0.7 million and $2.5 million of unrealized gains included in these amounts for the three and nine months ended September 30, 2011, respectively.
(2) Transfers out of Level 3 into Level 2 during 2011 were primarily due to the change in observability of forward NGL prices.

The following table provides quantitative information about our recurring Level 3 fair value measurements at September 30, 2012:

	Fair Value Financial Assets	Fair Value Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives – Propane	$ 4.2	$ 0.7	Discounted cash flow	Forward prices in excess of 1 year	$0.92-$0.98 /gallon
Commodity derivatives – Normal butane	0.4	0.7	Discounted cash flow	Forward prices in excess of 1 year	$1.49-$1.51 /gallon
Commodity derivatives – Natural gasoline	8.4	1.5	Discounted cash flow	Forward prices in excess of 1 year	$1.97-$2.02/gallon
Commodity derivatives – Crude oil	0.2	0.9	Discounted cash flow	Pricing data relative to quality and location attributes of crude oil	$92.19-$92.56 /barrel
Commodity derivatives – Natural gas	0.1	0.3	Discounted cash flow	Forward prices in excess of 3 years	$4.14-$4.39 /MMBtu
Total	$ 13.3	$ 4.1			

We believe certain forward commodity prices are the most significant unobservable inputs in determining our recurring Level 3 fair value measurements at September 30, 2012. 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"), which 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 presents information regarding certain long-lived assets measured at fair value on a nonrecurring basis for the nine months ended September 30, 2012.

	Carrying Value at September 30, 2012	Fair Value Measurements Using: 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 held and used	$ 2.2	$ --	$ --	$ 2.2	$ 2.6
Impairment of long-lived assets disposed of by sale	--	--	--	--	0.3
Impairment of long-lived assets disposed of other than by sale	--	--	--	--	54.7
Total					$ 57.6

Operating income for the three and nine months ended September 30, 2012 includes $43.1 million and $57.6 million, respectively, of non-cash asset impairment charges attributable to the following:

§ Long-lived assets held and used (pipeline terminal assets classified as property, plant and equipment) having a carrying amount of $4.8 million were written down to their estimated fair value of $2.2 million during the third quarter of 2012, resulting in non-cash asset impairment charges of $2.6 million.

§ Long-lived assets held for sale (primarily marine transportation assets) having a carrying amount of $0.8 million were written down to their fair value of $0.5 million during the first quarter of 2012, resulting in non-cash asset impairment charges of $0.3 million. These assets were sold in the second quarter of 2012.

§ Property, plant and equipment taken out of service and intangible assets having no future value were written off resulting in additional non-cash asset impairment charges of $40.5 million and $54.7 million for three and nine months ending September 30, 2012, respectively. Of these amounts, $29.2 million relates to the planned abandonment in 2013 of certain natural gas pipeline segments associated with our Texas Intrastate System.   This charge was recorded during the third quarter of 2012. The remaining charges generally relate to plant closures and other pipeline abandonments.

During the three and nine months ended September 30, 2011, certain assets included in property, plant and equipment having no future value and a combined carrying amount of $5.2 million were written-off, resulting in non-cash asset impairment charges for the respective periods.

As presented in the preceding table, our estimated fair values are based on the present value of expected future cash flows (Level 3). Forecast data and other assumptions supporting the fair value of long-lived assets being tested for impairment are based on the nonfinancial assets' highest and best use, which includes estimated probabilities where multiple cash flow outcomes are possible. Such probability weights are generally obtained from business management personnel having oversight responsibilities for the assets being tested. Key commercial assumptions (e.g., anticipated operating margins, throughput or processing volume growth rates and timing of cash flows) that represent Level 3 unobservable inputs and test results are reviewed and certified by members of senior management.

Other Fair Value Information

The carrying amounts of cash and cash equivalents (including restricted cash balances), accounts receivable and accounts payable approximate their fair values based on their short-term nature. The estimated total fair value of our fixed-rate debt obligations was $18.0 billion and $15.76 billion at September 30, 2012 and December 31, 2011, respectively. The aggregate carrying value of these debt obligations was $15.83 billion and $14.33 billion at September 30, 2012 and December 31, 2011, 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:

	September 30, 2012	December 31, 2011
NGLs	$ 702.5	$ 563.6
Petrochemicals and refined products	246.9	443.4
Crude oil	57.5	39.2
Natural gas	62.3	65.5
Total	$ 1,069.2	$ 1,111.7

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 September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Cost of sales (1)	$ 8,794.0	$ 9,787.6	$ 26,655.0	$ 28,397.2
Lower of cost or market adjustments	2.2	5.1	16.1	6.8

(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.

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	September 30, 2012	December 31, 2011
Plants, pipelines and facilities (1)	3-45 (6)	$ 24,789.0	$ 22,354.4
Underground and other storage facilities (2)	5-40 (7)	1,512.3	1,388.6
Platforms and facilities (3)	20-31	638.9	637.5
Transportation equipment (4)	3-10	167.8	151.5
Marine vessels (5)	15-30	677.1	615.9
Land		146.1	136.1
Construction in progress		2,293.4	2,145.6
Total		30,224.6	27,429.6
Less accumulated depreciation		5,913.1	5,238.0
Property, plant and equipment, net		$ 24,311.5	$ 22,191.6

(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 presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Depreciation expense (1)	$ 228.3	$ 195.0	$ 662.3	$ 571.3
Capitalized interest (2)	26.3	33.1	86.4	75.1

(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. Capitalized interest reduces interest expense during the period it is recorded.

Asset Retirement Obligations

We record asset retirement obligations ("AROs") related to legal requirements to perform retirement activities as specified in contractual arrangements and/or governmental regulations. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. Over time, the ARO liability is accreted to its present value (through accretion expense) and the capitalized amount is depreciated over the remaining useful life of the related long-term asset. Property, plant and equipment at September 30, 2012 and December 31, 2011 includes $41.2 million and $37.7 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

The following table summarizes changes in our ARO liability balance during the nine months ended September 30, 2012:

ARO liability balance, December 31, 2011	$ 112.0
Liabilities incurred during period	1.7
Liabilities settled during period	(21.2)
Revisions in estimated cash flows	11.3
Accretion expense	4.1
ARO liability balance, September 30, 2012	$ 107.9

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

Remainder of 2012	2013	2014	2015	2016
$ 1.5	$ 6.2	$ 6.6	$ 6.3	$ 6.6

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. Unless noted otherwise, we account for these investments using the equity method.

	Ownership Interest at September 30, 2012	September 30, 2012	December 31, 2011
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 31.9	$ 35.5
K/D/S Promix, L.L.C.	50%	41.6	40.7
Baton Rouge Fractionators LLC	32.2%	19.9	21.0
Skelly-Belvieu Pipeline Company, L.L.C.	50%	37.9	35.0
Texas Express Pipeline LLC ("Texas Express")	35%	79.9	13.9
Texas Express Gathering LLC ("TEG") (1)	45%	18.6	--
Front Range Pipeline LLC ("Front Range")	33.3%	12.1	--
Onshore Natural Gas Pipelines & Services:			
Evangeline (2)	--	--	4.4
White River Hub, LLC	50%	25.2	25.7
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline LLC	50%	254.6	170.7
Eagle Ford Pipeline LLC ("Eagle Ford Crude Oil Pipeline")	50%	117.1	--
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36%	48.3	55.4
Cameron Highway Oil Pipeline Company	50%	217.3	222.8
Deepwater Gateway, L.L.C.	50%	90.8	94.6
Neptune Pipeline Company, L.L.C.	25.7%	48.1	51.1
Southeast Keathley Canyon Pipeline Company L.L.C.	50%	57.5	1.0
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	8.2	9.5
Centennial Pipeline LLC ("Centennial")	50%	48.4	51.8
Other (3)	Various	3.0	3.4
Other Investments:			
Energy Transfer Equity (4)	--	--	1,023.1
Total		$ 1,160.4	$ 1,859.6

(1) In April 2012, we, along with Enbridge Midcoast Energy, LP ("Enbridge") and WGR Asset Holding Company LLC formed a new joint venture, TEG, to design and construct two NGL gathering systems to complement the Texas Express Pipeline. Enbridge will construct and operate the systems, which are expected to begin service in the second quarter of 2013.
(2) In June 2012, we acquired the remaining ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp. (collectively "Evangeline") and they became wholly owned subsidiaries of ours.
(3) 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.
(4) We ceased using the equity method to account for our investment in Energy Transfer Equity limited partner units effective January 18, 2012 and began accounting for them as available-for-sale securities. We completed the sale of the remaining Energy Transfer Equity units in April 2012 (see below).

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
NGL Pipelines & Services	$ 3.0	$ 4.3	$ 12.0	$ 16.4
Onshore Natural Gas Pipelines & Services	0.9	1.4	3.5	4.1
Onshore Crude Oil Pipelines & Services	16.5	(1.0)	20.6	(3.1)
Offshore Pipelines & Services	6.8	5.4	17.8	20.3
Petrochemical & Refined Products Services	(6.2)	(3.8)	(14.1)	(13.1)
Other Investments (1)	--	2.3	2.4	11.3
Total	$ 21.0	$ 8.6	$ 42.2	$ 35.9

(1) With respect to the nine months ended September 30, 2012, the amount presented reflects our equity in the income of Energy Transfer Equity from January 1, 2012 to January 18, 2012.

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

	September 30, 2012	December 31, 2011
NGL Pipelines & Services	$ 24.0	$ 24.7
Onshore Crude Oil Pipelines & Services	18.7	19.2
Offshore Pipelines & Services	13.9	14.8
Petrochemical & Refined Products Services	2.8	2.9
Other Investments (1)	--	1,119.0
Total	$ 59.4	$ 1,180.6

(1) On January 18, 2012, we discontinued using the equity method to account for our investment in Energy Transfer Equity common units and began accounting for this investment as an available-for-sale security. As a result, we no longer recognized any excess cost amounts associated with this investment.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
NGL Pipelines & Services	$ 0.2	$ 0.3	$ 0.7	$ 0.8
Onshore Crude Oil Pipelines & Services	0.2	0.1	0.5	0.5
Offshore Pipelines & Services	0.3	0.3	0.9	0.9
Petrochemical & Refined Products Services	--	0.1	0.1	0.1
Other Investments (1)	--	7.1	0.3	24.6
Total	$ 0.7	$ 7.9	$ 2.5	$ 26.9

(1) Reflects amortization of excess cost amounts related to our investment in Energy Transfer Equity from January 1, 2012 through January 18, 2012, which is the date we ceased using the equity method to account for this investment.

Liquidation of Investment in Energy Transfer Equity

The Other Investments segment included our noncontrolling ownership interest in Energy Transfer Equity, which was accounted for using the equity method until January 18, 2012. Since our ownership interest in Energy Transfer Equity exceeded 3% throughout calendar year 2011, we accounted for our investment in Energy Transfer Equity using the equity method and included gains from the sale of this investment in operating income. During the nine months ended September 30, 2011, we sold 8,564,136 Energy Transfer Equity common units for net cash proceeds of $333.5 million and recorded gains of $24.8 million from these sales. At December 31, 2011, we owned 29,303,514 common units of Energy Transfer Equity.

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

On January 18, 2012, we sold 22,762,636 of these common units in a private transaction, which generated cash proceeds of $825.1 million. As a result of the January 18 transaction, our ownership interest in Energy Transfer Equity was reduced below 3%, and we discontinued using the equity method to account for this investment and began accounting for it as an investment in available-for-sale equity securities. The remaining 6,540,878 units were sold systematically through April 27, 2012 and generated additional total cash proceeds of $270.2 million. In the aggregate, the liquidation of this investment during 2012 resulted in $68.8 million of gains that are presented as a component of other income.

All activities included in our former sixth reportable business segment, Other Investments, ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our investment in Energy Transfer Equity. See Note 11 for additional information regarding our business segments.

Formation of Front Range Joint Venture

In April 2012, we, along with WGR Asset Holding Company LLC, an affiliate of Anadarko Petroleum Corporation, and DCP Midstream Front Range LLC formed a new joint venture, Front Range, to design and construct a new NGL pipeline that will originate in the Denver-Julesburg Basin (the "DJ Basin") in Weld County, Colorado and extend 435 miles to Skellytown in Carson County, Texas. Each party holds a one-third ownership interest in the joint venture. The Front Range Pipeline, with connections to our Mid-America Pipeline System and the Texas Express Pipeline, will provide producers in the DJ Basin with access to the Gulf Coast, the largest NGL market in the U.S. Initial capacity on the Front Range Pipeline will be 150 MBPD, which can be readily expanded to 230 MBPD. We will construct and operate the pipeline, which is expected to begin service in the fourth quarter of 2013.

Formation of Eagle Ford Crude Oil Pipeline Joint Venture with Plains

In August 2012, we announced the formation of a 50/50 joint venture, Eagle Ford Pipeline LLC, with Plains All American Pipeline, L.P. ("Plains") to provide crude oil pipeline services to producers in South Texas. The arrangement provides for Enterprise and Plains to consolidate certain segments of previously announced pipeline projects servicing the Eagle Ford Shale supply basin. The joint venture pipeline system is supported by long-term commitments from producers totaling up to 210 MBPD of crude oil. This joint venture is expected to provide shippers with increased market flexibility and enable Enterprise and Plains to optimize their respective capital investments in the area.

The joint venture will include a 140-mile crude oil and condensate line extending from Gardendale, Texas in LaSalle County to Three Rivers, Texas in Live Oak County and continuing on to Corpus Christi, Texas, and a newly constructed 35-mile pipeline segment from Three Rivers to our Lyssy, Texas station in Wilson County. The system, which is currently under construction, is expected to have a capacity of 350 MBPD and will include a marine terminal facility at Corpus Christi and 1.8 MMBbls of operational storage capacity across the system. Segments of the new pipeline system are expected to be placed into service in the second quarter of 2013, with the balance of the system expected to be placed into service in the first quarter of 2014. Plains will serve as operator of the joint venture's pipeline system.

At Lyssy, the joint venture pipeline will interconnect with the Eagle Ford expansion of our South Texas Crude Oil Pipeline System, which commenced operations in June 2012. Our South Texas Crude Oil Pipeline System is not part of the new joint venture's pipeline system.

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

Summarized Income Statement Information of Unconsolidated Affiliates

The following table presents unaudited income statement information (on a 100% basis for the periods presented) of our unconsolidated affiliates, aggregated by the business segments to which they relate:

	Summarized Income Statement Information for the Three Months Ended					
	September 30, 2012			September 30, 2011		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income (Loss)	Net Income (Loss)
NGL Pipelines & Services	$ 63.9	$ 4.9	$ 4.9	$ 105.2	$ 20.7	$ 20.5
Onshore Natural Gas Pipelines & Services	2.8	1.8	1.8	59.5	2.9	3.0
Onshore Crude Oil Pipelines & Services	49.8	43.2	33.0	11.9	(0.5)	(0.5)
Offshore Pipelines & Services	42.5	18.1	17.4	38.8	15.0	14.6
Petrochemical & Refined Products Services	4.0	(9.9)	(11.8)	5.9	(4.8)	(6.9)
Other Investments	--	--	--	2,097.9	270.0	69.1

	Summarized Income Statement Information for the Nine Months Ended					
	September 30, 2012			September 30, 2011		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income (Loss)	Net Income (Loss)
NGL Pipelines & Services	$ 246.3	$ 47.2	$ 47.1	$ 321.7	$ 74.6	$ 74.5
Onshore Natural Gas Pipelines & Services	8.5	5.5	5.5	149.7	8.2	8.3
Onshore Crude Oil Pipelines & Services	83.6	51.4	41.1	32.7	(2.1)	(2.1)
Offshore Pipelines & Services	122.7	50.0	48.3	128.8	51.6	50.8
Petrochemical & Refined Products Services	15.3	(19.6)	(25.6)	25.2	(17.2)	(23.7)
Other Investments	--	--	--	6,061.9	894.8	224.0

We discontinued using the equity method to account for our investment in Energy Transfer Equity common units on January 18, 2012 (see "Liquidation of Investment in Energy Transfer Equity" within this Note 7). As a result, income statement data for Energy Transfer Equity, which was presented within the Other Investments segment in the table above, is not presented for the three and nine months ended September 30, 2012. For the three and nine months ended September 30, 2011, net income amounts presented for Energy Transfer Equity represents net income attributable to their partners.

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 September 30, 2012.

Note 8. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	September 30, 2012			December 31, 2011		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 340.8	$ (143.0)	$ 197.8	$ 340.8	$ (128.2)	$ 212.6
Contract-based intangibles	284.7	(152.1)	132.6	298.4	(169.7)	128.7
Segment total	625.5	(295.1)	330.4	639.2	(297.9)	341.3
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,163.6	(240.9)	922.7	1,163.6	(209.7)	953.9
Contract-based intangibles	468.3	(308.1)	160.2	464.8	(290.9)	173.9
Segment total	1,631.9	(549.0)	1,082.9	1,628.4	(500.6)	1,127.8
Onshore Crude Oil Pipelines & Services:						
Customer relationship intangibles	10.1	(4.6)	5.5	9.7	(4.1)	5.6
Contract-based intangibles	0.4	(0.2)	0.2	0.4	(0.2)	0.2
Segment total	10.5	(4.8)	5.7	10.1	(4.3)	5.8
Offshore Pipelines & Services:						
Customer relationship intangibles	203.9	(135.5)	68.4	205.8	(129.2)	76.6
Contract-based intangibles	1.2	(0.4)	0.8	1.2	(0.3)	0.9
Segment total	205.1	(135.9)	69.2	207.0	(129.5)	77.5
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.3	(32.1)	72.2	104.3	(28.4)	75.9
Contract-based intangibles	41.2	(5.5)	35.7	57.6	(29.7)	27.9
Segment total	145.5	(37.6)	107.9	161.9	(58.1)	103.8
Total all segments	$ 2,618.5	$ (1,022.4)	$ 1,596.1	$ 2,646.6	$ (990.4)	$ 1,656.2

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
NGL Pipelines & Services	$ 10.1	$ 10.3	$ 29.9	$ 30.7
Onshore Natural Gas Pipelines & Services	16.8	19.5	48.4	59.6
Onshore Crude Oil Pipelines & Services	0.2	0.1	0.5	0.3
Offshore Pipelines & Services	3.1	2.8	8.3	8.6
Petrochemical & Refined Products Services	2.1	4.3	8.8	12.9
Total	$ 32.3	$ 37.0	$ 95.9	$ 112.1

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

Remainder of 2012	2013	2014	2015	2016
$ 28.0	$ 114.6	$ 109.8	$ 108.4	$ 106.8

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. There have been no changes to our goodwill amounts since those reported in our 2011 Form 10-K.

Note 9. Debt Obligations

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

	September 30, 2012	December 31, 2011
EPO senior debt obligations:		
Senior Notes S, 7.625% fixed-rate, due February 2012	$ --	$ 490.5
Senior Notes P, 4.60% fixed-rate, due August 2012	--	500.0
Senior Notes C, 6.375% fixed-rate, due February 2013	350.0	350.0
Senior Notes T, 6.125% fixed-rate, due February 2013	182.5	182.5
Senior Notes M, 5.65% fixed-rate, due April 2013	400.0	400.0
Senior Notes U, 5.90% fixed-rate, due April 2013	237.6	237.6
Senior Notes O, 9.75% fixed-rate, due January 2014	500.0	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	--
Senior Notes AA, 3.20% fixed-rate, due February 2016	750.0	750.0
$3.5 Billion Multi-Year Revolving Credit Facility, variable-rate, due September 2016	85.0	150.0
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
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 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	--
Senior Notes GG, 4.45% fixed-rate, due February 2043	1,100.0	--
TEPPCO senior debt obligations:		
TEPPCO Senior Notes, 7.625% fixed-rate, due February 2012	--	9.5
TEPPCO Senior Notes, 6.125% fixed-rate, due February 2013	17.5	17.5
TEPPCO Senior Notes, 5.90% fixed-rate, due April 2013	12.4	12.4
TEPPCO Senior Notes, 6.65% fixed-rate, due April 2018	0.3	0.3
TEPPCO Senior Notes, 7.55% fixed-rate, due April 2038	0.4	0.4
Total principal amount of senior debt obligations	14,385.0	12,950.0
EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066	550.0	550.0
EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067	285.8	285.8
EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068	682.7	682.7
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067	14.2	14.2
Total principal amount of senior and junior debt obligations	15,917.7	14,482.7
Other, non-principal amounts:		
Change in fair value of debt hedged in fair value hedging relationship (1)	42.7	73.8
Unamortized discounts, net of premiums	(38.4)	(30.0)
Unamortized deferred net gains related to terminated interest rate swaps (1)	25.2	2.9
Total other, non-principal amounts	29.5	46.7
Less current maturities of debt (2)	(1,200.0)	(500.0)
Total long-term debt	$ 14,747.2	$ 14,029.4

(1) See Note 4 for information regarding our interest rate hedging activities.
(2) We expect to refinance the current maturities of our debt obligations prior to their maturity.

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 September 30, 2012 for the next five years, and in total thereafter:

		Scheduled Maturities of Debt					
	Total	Remainder of 2012	2013	2014	2015	2016	After 2016
Revolving Credit Facility	$ 85.0	$ --	$ --	$ --	$ --	$ 85.0	$ --
Senior Notes	14,300.0	--	1,200.0	1,150.0	1,300.0	750.0	9,900.0
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Total	$ 15,917.7	$ --	$ 1,200.0	$ 1,150.0	$ 1,300.0	$ 835.0	$ 11,432.7

Apart from those items discussed below and routine fluctuations in the balance of our revolving credit facility, there have been no significant changes in the terms or amounts of our consolidated debt obligations since those reported in our 2011 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 and August 2012

In February 2012, EPO issued $750.0 million in principal amount of 30-year unsecured Senior Notes EE at 99.542% of their principal amount. Senior Notes EE have a fixed interest rate of 4.85% and mature on August 15, 2042. Net proceeds from the issuance of Senior Notes EE were used to repay amounts due upon the maturity of $490.5 million principal amount of EPO Senior Notes S due February 2012 and $9.5 million principal amount of TEPPCO Senior Notes due February 2012 and for general company purposes.

In August 2012, EPO issued $650.0 million in principal amount of 3-year unsecured Senior Notes FF at 99.941% of their principal amount and $1.1 billion in principal amount of 30-year unsecured Senior Notes GG at 99.470% of their principal amount. Senior Notes FF have a fixed interest rate of 1.25% and mature on August 13, 2015, and Senior Notes GG have a fixed interest rate of 4.45% and mature on February 15, 2043. Net proceeds from the issuance of Senior Notes FF and GG were used to temporarily reduce borrowings under EPO's $3.5 Billion Multi-Year Revolving Credit Facility and for general company purposes.

Enterprise Products Partners L.P. has unconditionally guaranteed Senior Notes EE, FF and GG 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.

Commercial Paper Program

In August 2012, EPO established a commercial paper program under which it may issue (and have outstanding at any time) up to $2.0 billion in the aggregate of short-term commercial paper notes. As of September 30, 2012, no notes had been issued under this program. We intend to maintain a minimum available borrowing capacity under EPO's existing $3.5 Billion Multi-Year Revolving Credit Facility equal to any amount outstanding under commercial paper notes as a back-stop to the program. To the extent such commercial paper notes are issued in the future, they will be senior unsecured obligations of EPO that are unconditionally guaranteed by Enterprise Products Partners L.P.   Proceeds generated from the issuance of these notes are expected to be used for general company purposes.

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

Letters of Credit

At September 30, 2012, EPO had $37.5 million in letters of credit outstanding related to its commodity derivative instruments. These letters of credit do not reduce the amount available for borrowing under EPO's $3.5 Billion Multi-Year Revolving Credit Facility.

Lender Financial Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at September 30, 2012.

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 obligation during the nine months ended September 30, 2012:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
EPO $3.5 Billion Multi-Year Revolving Credit Facility	1.52% to 3.63%	1.57%

Note 10. Equity and Distributions

Partners' equity reflects the various classes of limited partner interests (common units, including restricted common units, and Class B units) that we have outstanding. The following table summarizes changes in the number of our common units outstanding during the nine months ended September 30, 2012:

	Common Units (Unrestricted)	Restricted Common Units	Total Common Units
Number of units outstanding at December 31, 2011	877,752,202	3,868,216	881,620,418
Common units issued in connection with underwritten offerings	9,200,000	--	9,200,000
Common units issued in connection with at-the-market program	1,648,291	--	1,648,291
Common units issued in connection with DRIP and EUPP	2,008,266	--	2,008,266
Common units issued in connection with the vesting of unit options	201,925	--	201,925
Common units issued in connection with the vesting of restricted common unit awards	1,264,483	(1,264,483)	--
Common units issued in connection with the vesting of other types of equity-based awards	16,667	--	16,667
Restricted common unit awards issued	--	1,556,038	1,556,038
Forfeiture of restricted common unit awards	--	(225,390)	(225,390)
Acquisition and cancellation of treasury units in connection with the vesting of equity-based awards	(382,420)	--	(382,420)
Number of units outstanding at September 30, 2012	891,709,414	3,934,381	895,643,795

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 "2010 Shelf") on file with the SEC. The 2010 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 2010 Shelf to issue its Senior Notes EE in February 2012 and Senior Notes FF and GG in August 2012 (see Note 9). In September 2012, we utilized the 2010 Shelf to issue 9,200,000 common units (including an over-allotment of 1,200,000 common units) to the public at an offering price of $53.07 per unit, which generated total net cash proceeds of $473.3 million.

In May 2012, we entered into an equity distribution agreement with certain broker-dealers pursuant to which we may offer and sell up to $1.0 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 the agreement 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. A registration statement covering the issuance of common units pursuant to this agreement was filed with the SEC in March 2012. During the third quarter of 2012, we issued 1,648,291 common units under this program for an aggregate price of $87.0 million, resulting in total net cash proceeds of $86.3 million. Proceeds from these sales were used for general company purposes, including funding capital expenditures.

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 ("DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of our common units they own by reinvesting the quarterly cash distributions they would otherwise receive from us into the purchase of additional common units. After taking into account the number of common units issued under the DRIP through September 30, 2012, we may issue an additional 24,267,343 common units under this plan. A total of 707,245 and 1,905,797 common units were issued during the three and nine months ended September 30, 2012, respectively, under our DRIP. Net cash proceeds from the issuance of common units under the DRIP were $35.8 million and $93.8 million for the three and nine months ended September 30, 2012, respectively.

In addition to the DRIP, we have a registration statement on file with the SEC authorizing the issuance of up to 440,879 of our common units in connection with an employee unit purchase plan ("EUPP"). After taking into account the number of common units issued under the EUPP through September 30, 2012, we may issue an additional 328,379 common units under this plan. A total of 30,412 and 102,469 common units were issued during the three and nine months ended September 30, 2012, respectively, under our EUPP. Net cash proceeds from the issuance of common units under the EUPP were $1.7 million and $5.4 million for the three and nine months ended September 30, 2012, respectively.

During the nine months ended September 30, 2012, 1,264,483 restricted common units and 4,100 other equity-based awards vested and converted to unrestricted common units. Of this amount, 382,420 common units were sold back to us by the recipients to cover related withholding tax requirements. We cancelled such treasury units immediately upon acquisition. For additional information regarding our equity-based awards, see Note 3.

The net cash proceeds we received from the issuance of common units during the nine months ended September 30, 2012 were used to temporarily reduce borrowings outstanding under EPO's revolving credit facility and for general company purposes.

In connection with the TEPPCO Merger in October 2009, a privately held affiliate of EPCO exchanged a portion of its TEPPCO units (based on a 1.24 exchange ratio) for 4,520,431 of our Class B units in lieu of receiving common units. The Class B units will automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth regular quarterly distribution following the closing date of the TEPPCO Merger. We expect this conversion will occur during the third quarter of 2013. Until the conversion occurs, the Class B units are not entitled to receive regular quarterly cash distributions; however, the Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions prior to conversion, have the same rights and privileges as our common units.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) primarily reflects the effective portion of the gain or loss on derivative instruments designated and qualified as cash flow hedges. Gain or loss amounts related to cash flow hedges recorded in accumulated other comprehensive income (loss) are reclassified to earnings in the same period(s) in which the underlying hedged forecasted transactions affect earnings. If it becomes probable that a forecasted transaction will not occur, the related net gain or loss in accumulated other comprehensive income (loss) is immediately reclassified into earnings.

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

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:

	September 30, 2012	December 31, 2011
Commodity derivative instruments (1)	$ 2.6	$ (21.4)
Interest rate derivative instruments (1)	(393.4)	(329.0)
Foreign currency translation adjustment (2)	1.7	1.7
Pension and postretirement benefit plans	0.8	(1.7)
Other	--	(1.0)
Total	$ (388.3)	$ (351.4)

(1) See Note 4 for additional information regarding our derivative instruments.
(2) Relates to transactions of a Canadian subsidiary.

Noncontrolling Interests

The following table presents additional information regarding noncontrolling interests as presented on our Unaudited Condensed Consolidated Balance Sheets at the dates indicated:

	September 30, 2012	December 31, 2011
Joint venture partners (1)	$ 108.3	$ 105.9

(1) Represents third party ownership interests in joint ventures that we consolidate, including Tri-States NGL Pipeline L.L.C., Independence Hub LLC, Rio Grande Pipeline Company and Wilprise Pipeline Company LLC.

The following table presents the components of net income attributable to noncontrolling interests as presented on our Unaudited Condensed Statements of Consolidated Operations for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Former owners of Duncan Energy Partners	$ --	$ 3.6	$ --	$ 20.9
Joint venture partners	1.1	4.5	6.2	15.8
Total	$ 1.1	$ 8.1	$ 6.2	$ 36.7

Prior to completion of the Duncan Merger (see Note 1), we accounted for the former owners' interest in Duncan Energy Partners as noncontrolling interest. Under this method of presentation, all pre-Duncan Merger revenues and expenses of Duncan Energy Partners are included in net income, and the former owners' share of the income of Duncan Energy Partners is a component of "Net income attributable to noncontrolling interests" as reflected on our Unaudited Condensed Statements of Consolidated Operations.

The following table presents cash distributions paid to and cash contributions received from noncontrolling interests as presented on our Unaudited Condensed Statements of Consolidated Cash Flows and Statements of Consolidated Equity for the periods presented:

	For the Nine Months Ended September 30,	
	2012	2011
Cash distributions paid to noncontrolling interests:		
Former owners of Duncan Energy Partners	$ --	$ 32.9
Joint venture partners	11.3	19.1
Total	$ 11.3	$ 52.0
Cash contributions from noncontrolling interests:		
Former owners of Duncan Energy Partners	$ --	$ 2.6
Joint venture partners	6.5	2.1
Total	$ 6.5	$ 4.7

Cash distributions paid to the former owners of Duncan Energy Partners (prior to the Duncan Merger) represent the quarterly cash distributions paid to its unitholders. Similarly, cash contributions received from the former owners of Duncan Energy Partners (prior to the Duncan Merger) represent net cash proceeds received from the issuance of its limited partner units.

Cash Distributions

The following table presents our declared quarterly cash distribution rates with respect to the quarter indicated:

	Distribution Per Common Unit		Record Date	Payment Date
2012				
1st Quarter	$	0.6275	04/30/12	05/09/12
2nd Quarter	$	0.6350	07/31/12	08/08/12
3rd Quarter	$	0.6500	10/31/12	11/08/12

A privately held affiliate of EPCO has agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from us with respect to a certain number of our common units it owns (the "Designated Units"). The temporary distribution waiver remains in effect for five years following the closing date of the Holdings Merger, which was completed in November 2010. For the remaining term of the waiver agreement, the number of Designated Units is as follows for distributions paid or to be paid, if any, during the following calendar years: 26,130,000 during 2012; 23,700,000 during 2013; 22,560,000 during 2014; and 17,690,000 during 2015.

Note 11. Business Segments

We currently have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

All activities included in our former sixth reportable business segment, Other Investments, ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our previously held investment in Energy Transfer Equity. See Note 7 for information regarding the liquidation of our investment in Energy Transfer Equity.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered an alternative to GAAP operating income.

We define total segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expenses; (ii) non-cash asset impairment charges; (iii) operating lease expenses for which we did not have the payment obligation; (iv) gains and losses from sales of assets and investments; and (v) general and administrative costs. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in the preparation of our consolidated financial statements. Gross operating margin is exclusive of other income and expense transactions, income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before any allocation of earnings to noncontrolling interests.

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

The following table presents our measurement of total segment gross operating margin for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Revenues	$ 10,468.7	$ 11,327.1	$ 31,511.0	$ 32,727.3
Less: Operating costs and expenses	(9,659.8)	(10,604.6)	(29,136.5)	(30,675.0)
Add: Equity in income of unconsolidated affiliates	21.0	8.6	42.2	35.9
Depreciation, amortization and accretion (1)	269.2	238.3	785.1	702.4
Non-cash asset impairment charges	43.1	5.2	57.6	5.2
Operating lease expenses paid by EPCO	--	--	--	0.3
Losses (gains) related to asset sales	(0.3)	17.6	(4.1)	(0.6)
Gains from sale of ownership interests in equity-method unconsolidated affiliate – Energy Transfer Equity (2)	--	(19.4)	--	(24.8)
Gains related to property damage insurance recoveries (see Note 16)	(2.3)	--	(30.0)	--
Total segment gross operating margin	$ 1,139.6	$ 972.8	$ 3,225.3	$ 2,770.7

(1) Amount is a component of "Depreciation, amortization and accretion" as presented on the Unaudited Condensed Statements of Consolidated Cash Flows.
(2) Amounts pertain to sales of limited partner interests in Energy Transfer Equity while this investment was accounted for using the equity method. See Note 7 for information regarding these sales.

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 September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Total segment gross operating margin	$ 1,139.6	$ 972.8	$ 3,225.3	$ 2,770.7
Adjustments to reconcile total segment gross operating margin to operating income:				
Amounts included in operating costs and expenses:				
Depreciation, amortization and accretion	(269.2)	(238.3)	(785.1)	(702.4)
Non-cash asset impairment charges	(43.1)	(5.2)	(57.6)	(5.2)
Operating lease expenses paid by EPCO	--	--	--	(0.3)
Gains (losses) related to asset sales	0.3	(17.6)	4.1	0.6
Gains from sale of ownership interests in equity-method unconsolidated affiliate – Energy Transfer Equity (see Note 7)	--	19.4	--	24.8
Gains related to property damage insurance recoveries (see Note 16)	2.3	--	30.0	--
General and administrative costs	(41.4)	(50.0)	(130.2)	(138.3)
Operating income	788.5	681.1	2,286.5	1,949.9
Other expense, net	(198.2)	(190.0)	(499.4)	(561.3)
Income before income taxes	$ 590.3	$ 491.1	$ 1,787.1	$ 1,388.6

Information by business segment, together with reconciliations to our consolidated financial statement totals, is presented in the following table:

	Reportable Business Segments							
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Other Investments	Adjustments and Eliminations	Consolidated Total
Revenues from third parties:								
Three months ended September 30, 2012	$ 3,389.6	$ 843.3	$ 4,505.1	$ 43.2	$ 1,680.0	$ --	$ --	$ 10,461.2
Three months ended September 30, 2011	4,323.8	855.9	3,957.1	57.7	1,968.7	--	--	11,163.2
Nine months ended September 30, 2012	11,071.6	2,349.1	13,167.4	145.1	4,713.9	--	--	31,447.1
Nine months ended September 30, 2011	12,339.3	2,590.1	11,609.3	179.4	5,451.0	--	--	32,169.1
Revenues from related parties:								
Three months ended September 30, 2012	2.2	3.2	0.1	2.0	--	--	--	7.5
Three months ended September 30, 2011	94.7	66.8	--	2.4	--	--	--	163.9
Nine months ended September 30, 2012	7.2	51.4	0.1	5.2	--	--	--	63.9
Nine months ended September 30, 2011	372.9	176.5	--	8.8	--	--	--	558.2
Intersegment and intrasegment revenues:								
Three months ended September 30, 2012	2,301.6	211.4	1,509.2	--	478.8	--	(4,501.0)	--
Three months ended September 30, 2011	3,253.6	257.2	1,342.2	4.8	442.9	--	(5,300.7)	--
Nine months ended September 30, 2012	7,396.3	614.1	4,975.6	5.0	1,357.4	--	(14,348.4)	--
Nine months ended September 30, 2011	9,956.4	782.0	3,526.9	6.6	1,361.5	--	(15,633.4)	--
Total revenues:								
Three months ended September 30, 2012	5,693.4	1,057.9	6,014.4	45.2	2,158.8	--	(4,501.0)	10,468.7
Three months ended September 30, 2011	7,672.1	1,179.9	5,299.3	64.9	2,411.6	--	(5,300.7)	11,327.1
Nine months ended September 30, 2012	18,475.1	3,014.6	18,143.1	155.3	6,071.3	--	(14,348.4)	31,511.0
Nine months ended September 30, 2011	22,668.6	3,548.6	15,136.2	194.8	6,812.5	--	(15,633.4)	32,727.3
Equity in income (loss) of unconsolidated affiliates:								
Three months ended September 30, 2012	3.0	0.9	16.5	6.8	(6.2)	--	--	21.0
Three months ended September 30, 2011	4.3	1.4	(1.0)	5.4	(3.8)	2.3	--	8.6
Nine months ended September 30, 2012	12.0	3.5	20.6	17.8	(14.1)	2.4	--	42.2
Nine months ended September 30, 2011	16.4	4.1	(3.1)	20.3	(13.1)	11.3	--	35.9
Gross operating margin:								
Three months ended September 30, 2012	615.8	183.5	117.6	40.6	182.1	--	--	1,139.6
Three months ended September 30, 2011	547.6	156.0	67.4	53.9	145.6	2.3	--	972.8
Nine months ended September 30, 2012	1,836.5	565.5	252.7	131.0	437.2	2.4	--	3,225.3
Nine months ended September 30, 2011	1,549.7	476.3	167.0	168.6	397.8	11.3	--	2,770.7
Segment assets:								
At September 30, 2012	8,838.0	10,398.4	1,838.0	1,976.8	3,815.7	--	2,293.4	29,160.3
At December 31, 2011	7,966.4	9,949.6	944.6	2,000.9	3,769.5	1,023.1	2,145.6	27,799.7
Property, plant and equipment, net: (see Note 6)								
At September 30, 2012	7,924.5	8,994.0	1,149.4	1,363.5	2,586.7	--	2,293.4	24,311.5
At December 31, 2011	7,137.8	8,495.4	456.9	1,416.4	2,539.5	--	2,145.6	22,191.6
Investments in unconsolidated affiliates: (see Note 7)								
At September 30, 2012	241.9	25.2	371.7	462.0	59.6	--	--	1,160.4
At December 31, 2011	146.1	30.1	170.7	424.9	64.7	1,023.1	--	1,859.6
Intangible assets, net: (see Note 8)								
At September 30, 2012	330.4	1,082.9	5.7	69.2	107.9	--	--	1,596.1
At December 31, 2011	341.3	1,127.8	5.8	77.5	103.8	--	--	1,656.2
Goodwill: (see Note 8)								
At September 30, 2012	341.2	296.3	311.2	82.1	1,061.5	--	--	2,092.3
At December 31, 2011	341.2	296.3	311.2	82.1	1,061.5	--	--	2,092.3

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 September 30, 2012	For the Three Months Ended September 30, 2011	For the Nine Months Ended September 30, 2012	For the Nine Months Ended September 30, 2011
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 3,151.9	$ 4,164.9	$ 10,401.1	$ 12,054.8
Midstream services	239.9	253.6	677.7	657.4
Total	3,391.8	4,418.5	11,078.8	12,712.2
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	608.2	704.7	1,691.6	2,136.9
Midstream services	238.3	218.0	708.9	629.7
Total	846.5	922.7	2,400.5	2,766.6
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	4,471.8	3,929.8	13,093.4	11,535.9
Midstream services	33.4	27.3	74.1	73.4
Total	4,505.2	3,957.1	13,167.5	11,609.3
Offshore Pipelines & Services:				
Sales of natural gas	0.2	0.3	0.3	0.9
Sales of crude oil	3.1	1.3	4.5	7.1
Midstream services	41.9	58.5	145.5	180.2
Total	45.2	60.1	150.3	188.2
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	1,498.9	1,767.2	4,166.9	4,868.7
Midstream services	181.1	201.5	547.0	582.3
Total	1,680.0	1,968.7	4,713.9	5,451.0
Total consolidated revenues	$ 10,468.7	$ 11,327.1	$ 31,511.0	$ 32,727.3
Consolidated costs and expenses				
Operating costs and expenses:				
Cost of sales	$ 8,794.0	$ 9,787.6	$ 26,655.0	$ 28,397.2
Other operating costs and expenses (1)	556.1	575.3	1,672.9	1,595.6
Depreciation, amortization and accretion	269.2	238.3	785.1	702.4
Losses (gains) related to asset sales	(0.3)	17.6	(4.1)	(0.6)
Gains from sale of ownership interests in equity-method unconsolidated affiliate – Energy Transfer Equity (2)	--	(19.4)	--	(24.8)
Gains related to property damage insurance recoveries	(2.3)	--	(30.0)	--
Non-cash asset impairment charges	43.1	5.2	57.6	5.2
General and administrative costs	41.4	50.0	130.2	138.3
Total consolidated costs and expenses	$ 9,701.2	$ 10,654.6	$ 29,266.7	$ 30,813.3

(1) Represents cost of operating our plants, pipelines and other fixed assets, excluding non-cash depreciation, amortization and accretion charges.
(2) Amounts pertain to sales of limited partner interests in Energy Transfer Equity while this investment was accounted for using the equity method. See Note 7 for information regarding these sales.

Period-to-period 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.

Note 12. Related Party Transactions

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Revenues – related parties:				
Energy Transfer Equity and subsidiaries	$ --	$ 95.8	$ --	$ 392.7
Other unconsolidated affiliates	7.5	68.1	63.9	165.5
Total revenue – related parties	$ 7.5	$ 163.9	$ 63.9	$ 558.2
Costs and expenses – related parties:				
EPCO and affiliates	$ 210.8	$ 187.8	$ 616.9	$ 553.2
Energy Transfer Equity and subsidiaries	--	278.8	--	769.2
Other unconsolidated affiliates	15.0	21.8	27.3	43.4
Total costs and expenses – related parties	$ 225.8	$ 488.4	$ 644.2	$ 1,365.8

Energy Transfer Equity was a related party to us during the period in which we accounted for our investment in its limited partner units using the equity method of accounting. We ceased reporting Energy Transfer Equity as a related party in January 2012. See Note 7 for information regarding the liquidation of our investment in Energy Transfer Equity.

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

	September 30, 2012	December 31, 2011
Accounts receivable - related parties:		
Energy Transfer Equity and subsidiaries	$ --	$ 28.4
Other unconsolidated affiliates	10.4	15.1
Total accounts receivable – related parties	$ 10.4	$ 43.5
Accounts payable - related parties:		
EPCO and affiliates	$ 95.3	$ 108.3
Energy Transfer Equity and subsidiaries	--	92.6
Other unconsolidated affiliates	17.3	10.7
Total accounts payable – related parties	$ 112.6	$ 211.6

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 sole general partner), which are not a part of our consolidated group of companies.

EPCO is a privately held company controlled collectively by the EPCO Trustees. At September 30, 2012, EPCO and its privately held affiliates (including Dan Duncan LLC and certain Duncan family trusts, the beneficiaries of which include the estate of Mr. Duncan) beneficially owned the following limited partner interests in us:

Number of Units	Percentage of Total Units Outstanding
338,930,881 (1)	37.7%

(1) Includes 4,520,431 Class B units.

Dan Duncan LLC owns 100% of our general partner, Enterprise GP.

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 operations and to meet their debt obligations. During the nine months ended September 30, 2012 and 2011, we paid EPCO and its privately held affiliates cash distributions of $557.7 million and $522.8 million, respectively.

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. The following table presents costs and expenses related to the ASA and other EPCO transactions for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Operating costs and expenses	$ 185.3	$ 157.2	$ 541.6	$ 462.5
General and administrative expenses	25.5	30.6	75.3	90.7
Total costs and expenses	$ 210.8	$ 187.8	$ 616.9	$ 553.2

Note 13. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss attributable to our limited partners by the weighted-average number of our distribution-bearing units outstanding during a period, which excludes the Designated Units (see Note 10) to the extent that such units do not participate in the distributions to be paid with respect to such period.

Diluted earnings per unit is computed by dividing net income or loss attributable to our limited partners by the sum of (i) the weighted-average number of our distribution-bearing units outstanding during a period (as used in determining basic earnings per unit), (ii) the weighted-average number of our Class B units outstanding during a period, (iii) the weighted-average number of Designated Units outstanding during a period and (iv) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

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

	For the Three Months Ended September 30, 2012	For the Three Months Ended September 30, 2011	For the Nine Months Ended September 30, 2012	For the Nine Months Ended September 30, 2011
BASIC EARNINGS PER UNIT				
Numerator:				
Net income attributable to limited partners	$ 586.8	$ 471.4	$ 1,804.4	$ 1,325.8
Denominator:				
Weighted-average number of:				
Distribution-bearing common units outstanding	859.3	821.9	857.9	817.0
Basic earnings per unit:				
Net income attributable to limited partners	$ 0.68	$ 0.57	$ 2.10	$ 1.62
DILUTED EARNINGS PER UNIT				
Numerator:				
Net income attributable to limited partners	$ 586.8	$ 471.4	$ 1,804.4	$ 1,325.8
Denominator:				
Weighted-average number of:				
Distribution-bearing common units outstanding	859.3	821.9	857.9	817.0
Class B units	4.5	4.5	4.5	4.5
Designated Units (see Note 10)	26.1	30.6	26.1	30.6
Incremental option units	1.5	1.2	1.5	1.2
Total	891.4	858.2	890.0	853.3
Diluted earnings per unit:				
Net income attributable to limited partners	$ 0.66	$ 0.55	$ 2.03	$ 1.55

Note 14. Commitments and Contingencies

As part of our normal business activities, we may be named as defendants in legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to fully indemnify us against losses arising from future legal proceedings. We will vigorously defend the partnership in litigation matters.

Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the possible need for accounting recognition and disclosure of these contingencies. We accrue an undiscounted liability for those contingencies where the loss is probable and the amount can be reasonably estimated. If a range of probable loss amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum amount in the range is accrued.

We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when the likelihood of loss is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material to our consolidated financial statements, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss. Based on a consideration of all relevant known facts and circumstances, we do not believe that the ultimate outcome of any currently pending litigation directed against us will have a material impact on our consolidated financial statements either individually at the claim level or in the aggregate.

At September 30, 2012 and December 31, 2011, our accruals for litigation contingencies were $11.5 million and $16.5 million, respectively, and were recorded in our Unaudited Condensed Consolidated Balance Sheets as a component of "Other current liabilities." Our accruals for litigation contingencies are recorded on an undiscounted basis. 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.

Contractual Obligations

Scheduled Maturities of Long-Term Debt. With the exception of routine fluctuations in the balance of our revolving credit facility, the issuance of senior notes in February 2012 and August 2012, and the scheduled repayment of maturing debt obligations, there have been no significant changes in our consolidated debt obligations since those reported in our 2011 Form 10-K. See Note 9 for additional information regarding our consolidated debt obligations.

Operating Lease Obligations. Consolidated lease and rental expense was $26.0 million and $21.2 million during the three months ended September 30, 2012 and 2011, respectively. For the nine months ended September 30, 2012 and 2011, consolidated lease and rental expense was $71.1 million and $63.2 million, respectively. There have been no material changes in our operating lease commitments since those reported in our 2011 Form 10-K.

Purchase Obligations. There have been no material changes in our consolidated purchase obligations since those reported in our 2011 Form 10-K.

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally make claims against such parties or have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of September 30, 2012, our contingent claims against such parties were $38.6 million and claims against us were $42.3 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated at this time. With respect to claims against us, we believe that the likelihood of a material loss resulting from such claims is remote. Accordingly, no accruals for loss contingencies related to these matters have been recorded.

Note 15. Supplemental Cash Flow Information

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

	For the Nine Months Ended September 30, 2012	2011
Decrease (increase) in:		
Accounts receivable – trade	$ 121.7	$ (218.3)
Accounts receivable – related parties	27.5	(1.0)
Inventories	(229.2)	(21.1)
Prepaid and other current assets	(11.3)	(35.0)
Other assets	(54.3)	(48.6)
Increase (decrease) in:		
Accounts payable – trade	36.2	114.1
Accounts payable – related parties	(98.9)	79.0
Accrued product payables	(609.4)	285.6
Accrued interest	(100.0)	(68.7)
Other current liabilities	26.9	(40.1)
Other liabilities	(19.4)	15.7
Net effect of changes in operating accounts	$ (910.2)	$ 61.6

We incurred liabilities for construction in progress that had not been paid at September 30, 2012 and December 31, 2011 of $240.6 million and $286.9 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.

Proceeds from asset sales increased $696.9 million period-to-period primarily due to the liquidation of our investment in Energy Transfer Equity during 2012 (see Note 7). The following table summarizes our cash proceeds from asset sales for the periods indicated:

	For the Nine Months Ended September 30,	
	2012	2011
Proceeds from sales of Energy Transfer Equity common units (see Note 7)	$ 1,095.3	$ 333.5
Proceeds from other asset sales	42.1	107.0
Total proceeds from asset sales	$ 1,137.4	$ 440.5

See Note 16 for information regarding the collection of $30.0 million of nonrefundable property damage insurance proceeds during the nine months ended September 30, 2012.

See Note 10 for information regarding cash amounts attributable to noncontrolling interests.

Note 16. Insurance Matters

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other insurance coverage, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance may not fully cover every type of damage, interruption or other loss that might occur. If we were to incur a significant loss for which we were not fully insured, it could have a material impact on our financial position, results of operations and cash flows. In addition, there may be timing differences between amounts we accrue related to property damage expense, amounts we are required to pay in connection with a loss and amounts we subsequently receive from insurance carriers as reimbursements. Any event that materially interrupts the revenues generated by our consolidated operations, or other losses that require us to make material expenditures not reimbursed by insurance, could reduce our ability to pay distributions to our unitholders and, accordingly, adversely affect the market price of our common units.

Involuntary conversions result from the loss of an asset because of some unforeseen event (e.g., destruction due to fire). Some of these events are insurable, thus resulting in a property damage insurance recovery. Amounts we receive from insurance carriers are net of any deductibles related to the covered event. EPCO renewed its annual insurance programs during the second quarter of 2012. Under terms of the renewed policies, EPCO's deductibles for property damage claims now range from $5.0 million to $60.0 million depending on the nature of the loss (windstorm or non-windstorm) and the assets involved (onshore or offshore). We continue to maintain business interruption coverage for our onshore and offshore assets, except for those situations involving windstorm-related downtime for our offshore assets.

After performing a cost-benefit analysis, management elected to forego windstorm coverage for our Gulf of Mexico offshore assets. The combination of increasingly high deductibles and premiums resulted in such coverage being uneconomic to us; therefore, we chose to self-insure such operations for the current annual policy period. Although the new EPCO policies do not provide any windstorm coverage for offshore assets, producers affiliated with our Independence Hub and Marco Polo platforms provide physical damage windstorm coverage of $350.0 million for each of these key offshore assets.

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

During the three and nine months ended September 30, 2012, we collected $2.3 million and $30.0 million, respectively, of nonrefundable cash proceeds from insurance carriers that we recognized as a gain within operating costs and expenses. These proceeds relate to property damage claims we made in connection with the February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. To the extent that additional non-refundable insurance proceeds related to this incident are received, we expect to record gains equal to such proceeds.

Note 17. Condensed Consolidating Financial Information

EPO conducts substantially 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.

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
September 30, 2012

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	$ 21.3	$ 21.8	$ (9.8)	$ 33.3	$ --	$ --	$ 33.3
Accounts receivable – trade, net	1,474.0	2,915.6	(0.2)	4,389.4	--	--	4,389.4
Accounts receivable – related parties	155.9	1,412.4	(1,557.9)	10.4	85.2	(85.2)	10.4
Inventories	924.8	145.7	(1.3)	1,069.2	--	--	1,069.2
Prepaid and other current assets	188.5	209.4	(7.2)	390.7	0.1	--	390.8
Total current assets	2,764.5	4,704.9	(1,576.4)	5,893.0	85.3	(85.2)	5,893.1
Property, plant and equipment, net	1,626.1	22,685.2	0.2	24,311.5	--	--	24,311.5
Investments in unconsolidated affiliates	27,583.5	1,684.2	(28,107.3)	1,160.4	12,864.1	(12,864.1)	1,160.4
Intangible assets, net	78.9	1,517.2	--	1,596.1	--	--	1,596.1
Goodwill	458.9	1,633.4	--	2,092.3	--	--	2,092.3
Other assets	134.5	90.6	(0.9)	224.2	0.2	--	224.4
Total assets	$ 32,646.4	$ 32,315.5	$ (29,684.4)	$ 35,277.5	$ 12,949.6	$ (12,949.3)	$ 35,277.8
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 1,170.1	$ 29.9	$ --	$ 1,200.0	$ --	$ --	$ 1,200.0
Accounts payable – trade	204.9	603.5	(9.8)	798.6	--	--	798.6
Accounts payable – related parties	1,613.8	136.8	(1,552.8)	197.8	--	(85.2)	112.6
Accrued product payables	1,574.3	2,750.8	(6.6)	4,318.5	--	--	4,318.5
Accrued interest	187.3	0.9	--	188.2	--	--	188.2
Other current liabilities	294.8	330.5	(7.2)	618.1	--	(0.2)	617.9
Total current liabilities	5,045.2	3,852.4	(1,576.4)	7,321.2	--	(85.4)	7,235.8
Long-term debt	14,732.2	15.0	--	14,747.2	--	--	14,747.2
Deferred tax liabilities	4.2	17.9	(0.9)	21.2	--	(0.4)	20.8
Other long-term liabilities	22.7	193.4	--	216.1	--	--	216.1
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	12,842.1	28,161.3	(28,160.0)	12,843.4	12,949.6	(12,843.4)	12,949.6
Noncontrolling interests	--	75.5	52.9	128.4	--	(20.1)	108.3
Total equity	12,842.1	28,236.8	(28,107.1)	12,971.8	12,949.6	(12,863.5)	13,057.9
Total liabilities and equity	$ 32,646.4	$ 32,315.5	$ (29,684.4)	$ 35,277.5	$ 12,949.6	$ (12,949.3)	$ 35,277.8

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
December 31, 2011

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	$ 48.2	$ 21.3	$ (11.2)	$ 58.3	$ --	$ --	$ 58.3
Accounts receivable – trade, net	1,599.4	2,913.2	(10.8)	4,501.8	--	--	4,501.8
Accounts receivable – related parties	141.1	2,155.5	(2,252.0)	44.6	(1.1)	--	43.5
Inventories	943.6	170.5	(2.4)	1,111.7	--	--	1,111.7
Prepaid and other current assets	216.8	152.6	(16.0)	353.4	--	--	353.4
Total current assets	2,949.1	5,413.1	(2,292.4)	6,069.8	(1.1)	--	6,068.7
Property, plant and equipment, net	1,477.5	20,723.7	(9.6)	22,191.6	--	--	22,191.6
Investments in unconsolidated affiliates	27,060.0	8,266.7	(33,467.1)	1,859.6	12,114.5	(12,114.5)	1,859.6
Intangible assets, net	142.4	1,527.4	(13.6)	1,656.2	--	--	1,656.2
Goodwill	458.9	1,633.4	--	2,092.3	--	--	2,092.3
Other assets	146.4	107.5	2.8	256.7	--	--	256.7
Total assets	$ 32,234.3	$ 37,671.8	$ (35,779.9)	$ 34,126.2	$ 12,113.4	$ (12,114.5)	$ 34,125.1
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 500.0	$ --	$ --	$ 500.0	$ --	$ --	$ 500.0
Accounts payable – trade	205.6	578.6	(11.2)	773.0	--	--	773.0
Accounts payable – related parties	2,407.2	71.9	(2,267.5)	211.6	--	--	211.6
Accrued product payables	2,141.0	2,912.4	(6.3)	5,047.1	--	--	5,047.1
Accrued interest	287.1	1.0	--	288.1	--	--	288.1
Other current liabilities	298.1	321.8	(7.4)	612.5	--	0.1	612.6
Total current liabilities	5,839.0	3,885.7	(2,292.4)	7,432.3	--	0.1	7,432.4
Long-term debt	13,975.1	54.3	--	14,029.4	--	--	14,029.4
Deferred tax liabilities	22.2	67.1	2.8	92.1	--	(0.9)	91.2
Other long-term liabilities	155.3	197.5	--	352.8	--	--	352.8
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	12,242.7	28,799.8	(28,946.4)	12,096.1	12,113.4	(12,096.1)	12,113.4
Noncontrolling interests	--	4,667.4	(4,543.9)	123.5	--	(17.6)	105.9
Total equity	12,242.7	33,467.2	(33,490.3)	12,219.6	12,113.4	(12,113.7)	12,219.3
Total liabilities and equity	$ 32,234.3	$ 37,671.8	$ (35,779.9)	$ 34,126.2	$ 12,113.4	$ (12,114.5)	$ 34,125.1

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 September 30, 2012

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 6,392.6	$ 7,072.5	$ (2,996.4)	$ 10,468.7	$ --	$ --	$ 10,468.7
Costs and expenses:							
Operating costs and expenses	6,192.8	6,464.8	(2,997.8)	9,659.8	--	--	9,659.8
General and administrative costs	(4.4)	45.6	--	41.2	0.2	--	41.4
Total costs and expenses	6,188.4	6,510.4	(2,997.8)	9,701.0	0.2	--	9,701.2
Equity in income of unconsolidated affiliates	581.4	25.7	(586.1)	21.0	587.0	(587.0)	21.0
Operating income	785.6	587.8	(584.7)	788.7	586.8	(587.0)	788.5
Other income (expense):							
Interest expense	(199.0)	(0.7)	--	(199.7)	--	--	(199.7)
Other, net	--	1.5	--	1.5	--	--	1.5
Total other expense, net	(199.0)	0.8	--	(198.2)	--	--	(198.2)
Income before income taxes	586.6	588.6	(584.7)	590.5	586.8	(587.0)	590.3
Provision for income taxes	(1.4)	(0.8)	--	(2.2)	--	(0.2)	(2.4)
Net income	585.2	587.8	(584.7)	588.3	586.8	(587.2)	587.9
Net loss (income) attributable to noncontrolling interests	--	(0.4)	(1.2)	(1.6)	--	0.5	(1.1)
Net income attributable to entity	$ 585.2	$ 587.4	$ (585.9)	$ 586.7	$ 586.8	$ (586.7)	$ 586.8

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Three Months Ended September 30, 2011

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 8,270.5	$ 7,066.8	$ (4,010.2)	$ 11,327.1	$ --	$ --	$ 11,327.1
Costs and expenses:							
Operating costs and expenses	8,137.1	6,478.9	(4,011.4)	10,604.6	--	--	10,604.6
General and administrative costs	3.6	45.7	--	49.3	0.7	--	50.0
Total costs and expenses	8,140.7	6,524.6	(4,011.4)	10,653.9	0.7	--	10,654.6
Equity in income of unconsolidated affiliates	524.1	16.6	(532.1)	8.6	472.1	(472.1)	8.6
Operating income	653.9	558.8	(530.9)	681.8	471.4	(472.1)	681.1
Other income (expense):							
Interest expense	(180.7)	(10.1)	1.8	(189.0)	--	--	(189.0)
Other, net	2.0	(1.2)	(1.8)	(1.0)	--	--	(1.0)
Total other expense, net	(178.7)	(11.3)	--	(190.0)	--	--	(190.0)
Income before income taxes	475.2	547.5	(530.9)	491.8	471.4	(472.1)	491.1
Provision for income taxes	(4.6)	(6.9)	--	(11.5)	--	(0.1)	(11.6)
Net income	470.6	540.6	(530.9)	480.3	471.4	(472.2)	479.5
Net loss (income) attributable to noncontrolling interests	--	(9.4)	1.0	(8.4)	--	0.3	(8.1)
Net income attributable to entity	$ 470.6	$ 531.2	$ (529.9)	$ 471.9	$ 471.4	$ (471.9)	$ 471.4

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Nine Months Ended September 30, 2012

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 20,066.0	$ 20,927.0	$ (9,482.0)	$ 31,511.0	$ --	$ --	$ 31,511.0
Costs and expenses:							
Operating costs and expenses	19,467.0	19,151.4	(9,481.9)	29,136.5	--	--	29,136.5
General and administrative costs	20.1	108.9	--	129.0	1.2	--	130.2
Total costs and expenses	19,487.1	19,260.3	(9,481.9)	29,265.5	1.2	--	29,266.7
Equity in income of unconsolidated affiliates	1,774.7	53.1	(1,785.6)	42.2	1,805.6	(1,805.6)	42.2
Operating income	2,353.6	1,719.8	(1,785.7)	2,287.7	1,804.4	(1,805.6)	2,286.5
Other income (expense):							
Interest expense	(570.3)	(2.5)	--	(572.8)	--	--	(572.8)
Other, net	0.1	73.3	--	73.4	--	--	73.4
Total other expense, net	(570.2)	70.8	--	(499.4)	--	--	(499.4)
Income before income taxes	1,783.4	1,790.6	(1,785.7)	1,788.3	1,804.4	(1,805.6)	1,787.1
Benefit from income taxes	21.0	2.9	-	23.9	--	(0.4)	23.5
Net income	1,804.4	1,793.5	(1,785.7)	1,812.2	1,804.4	(1,806.0)	1,810.6
Net loss (income) attributable to noncontrolling interests	--	(4.6)	(3.2)	(7.8)	--	1.6	(6.2)
Net income attributable to entity	$ 1,804.4	$ 1,788.9	$ (1,788.9)	$ 1,804.4	$ 1,804.4	$ (1,804.4)	$ 1,804.4

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Nine Months Ended September 30, 2011

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 24,554.8	$ 20,340.2	$ (12,167.7)	$ 32,727.3	$ --	$ --	$ 32,727.3
Costs and expenses:							
Operating costs and expenses	24,139.5	18,704.2	(12,168.7)	30,675.0	--	--	30,675.0
General and administrative costs	7.9	123.2	--	131.1	7.2	--	138.3
Total costs and expenses	24,147.4	18,827.4	(12,168.7)	30,806.1	7.2	--	30,813.3
Equity in income of unconsolidated affiliates	1,474.9	73.3	(1,512.3)	35.9	1,333.0	(1,333.0)	35.9
Operating income	1,882.3	1,586.1	(1,511.3)	1,957.1	1,325.8	(1,333.0)	1,949.9
Other income (expense):							
Interest expense	(543.7)	(23.0)	5.6	(561.1)	--	--	(561.1)
Other, net	5.9	(0.5)	(5.6)	(0.2)	--	--	(0.2)
Total other expense, net	(537.8)	(23.5)	--	(561.3)	--	--	(561.3)
Income before income taxes	1,344.5	1,562.6	(1,511.3)	1,395.8	1,325.8	(1,333.0)	1,388.6
Provision for income taxes	(13.1)	(12.8)	--	(25.9)	--	(0.2)	(26.1)
Net income	1,331.4	1,549.8	(1,511.3)	1,369.9	1,325.8	(1,333.2)	1,362.5
Net loss (income) attributable to noncontrolling interests	--	(20.3)	(17.2)	(37.5)	--	0.8	(36.7)
Net income attributable to entity	$ 1,331.4	$ 1,529.5	$ (1,528.5)	$ 1,332.4	$ 1,325.8	$ (1,332.4)	$ 1,325.8

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 September 30, 2012

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 559.8	$ 543.5	$ (584.7)	$ 518.6	$ 517.2	$ (517.5)	$ 518.3
Comprehensive income attributable to noncontrolling interests	--	(0.4)	(1.2)	(1.6)	--	0.5	(1.1)
Comprehensive income attributable to entity	$ 559.8	$ 543.1	$ (585.9)	$ 517.0	$ 517.2	$ (517.0)	$ 517.2

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
Three Months Ended September 30, 2011

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 220.8	$ 560.8	$ (530.9)	$ 250.7	$ 241.9	$ (242.6)	$ 250.0
Comprehensive income attributable to noncontrolling interests	--	(9.4)	1.0	(8.4)	--	0.3	(8.1)
Comprehensive income attributable to entity	$ 220.8	$ 551.4	$ (529.9)	$ 242.3	$ 241.9	$ (242.3)	$ 241.9

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
Nine Months Ended September 30, 2012

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 1,743.4	$ 1,817.5	$ (1,785.7)	$ 1,775.2	$ 1,767.5	$ (1,769.0)	$ 1,773.7
Comprehensive income attributable to noncontrolling interests	--	(4.6)	(3.2)	(7.8)	--	1.6	(6.2)
Comprehensive income attributable to entity	$ 1,743.4	$ 1,812.9	$ (1,788.9)	$ 1,767.4	$ 1,767.5	$ (1,767.4)	$ 1,767.5

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
Nine Months Ended September 30, 2011

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 1,038.0	$ 1,539.9	$ (1,511.3)	$ 1,066.6	$ 1,022.6	$ (1,029.9)	$ 1,059.3
Comprehensive income attributable to noncontrolling interests	--	(20.3)	(17.2)	(37.5)	--	0.8	(36.7)
Comprehensive income attributable to entity	$ 1,038.0	$ 1,519.6	$ (1,528.5)	$ 1,029.1	$ 1,022.6	$ (1,029.1)	$ 1,022.6

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
Nine Months Ended September 30, 2012

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 1,804.4	$ 1,793.5	$ (1,785.7)	$ 1,812.2	$ 1,804.4	$ (1,806.0)	$ 1,810.6
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	89.9	728.0	--	817.9	--	--	817.9
Equity in income of unconsolidated affiliates	(1,774.7)	(53.1)	1,785.6	(42.2)	(1,805.6)	1,805.6	(42.2)
Distributions received from unconsolidated affiliates	2,898.7	54.3	(2,885.5)	67.5	1,643.4	(1,643.4)	67.5
Net effect of changes in operating accounts and other operating activities	(2,005.1)	1,057.8	1.4	(945.9)	(92.5)	0.4	(1,038.0)
Net cash flows provided by operating activities	1,013.2	3,580.5	(2,884.2)	1,709.5	1,549.7	(1,643.4)	1,615.8
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(161.2)	(2,536.7)	--	(2,697.9)	--	--	(2,697.9)
Proceeds from asset sales	1,109.1	28.3	--	1,137.4	--	--	1,137.4
Other investing activities	(2,161.7)	(224.2)	2,051.4	(334.5)	(571.5)	571.5	(334.5)
Cash used in investing activities	(1,213.8)	(2,732.6)	2,051.4	(1,895.0)	(571.5)	571.5	(1,895.0)
Financing activities:							
Borrowings under debt agreements	7,141.4	--	--	7,141.4	--	--	7,141.4
Repayments of debt	(5,706.5)	(9.5)	--	(5,716.0)	--	--	(5,716.0)
Cash distributions paid to partners	(1,643.4)	(2,889.7)	2,889.7	(1,643.4)	(1,613.4)	1,643.4	(1,613.4)
Cash distributions paid to noncontrolling interests	--	(7.1)	(4.2)	(11.3)	--	--	(11.3)
Cash contributions from noncontrolling interests	--	--	6.5	6.5	--	--	6.5
Net cash proceeds from issuance of common units	--	--	--	--	654.8	--	654.8
Cash contributions from owners	571.5	2,057.8	(2,057.8)	571.5	--	(571.5)	--
Other financing activities	(168.5)	--	--	(168.5)	(19.6)	--	(188.1)
Cash provided by (used in) financing activities	194.5	(848.5)	834.2	180.2	(978.2)	1,071.9	273.9
Net change in cash and cash equivalents	(6.1)	(0.6)	1.4	(5.3)	--	--	(5.3)
Cash and cash equivalents, January 1	9.7	21.3	(11.2)	19.8	--	--	19.8
Cash and cash equivalents, September 30	$ 3.6	$ 20.7	$ (9.8)	$ 14.5	$ --	$ --	$ 14.5

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
Nine Months Ended September 30, 2011

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 1,331.4	$ 1,549.8	$ (1,511.3)	$ 1,369.9	$ 1,325.8	$ (1,333.2)	$ 1,362.5
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	86.4	653.8	(1.0)	739.2	--	--	739.2
Equity in income of unconsolidated affiliates	(1,474.9)	(73.3)	1,512.3	(35.9)	(1,333.0)	1,333.0	(35.9)
Distributions received from unconsolidated affiliates	141.6	164.1	(183.2)	122.5	1,480.2	(1,480.2)	122.5
Net effect of changes in operating accounts and other operating activities	1,116.0	(521.5)	(550.8)	43.7	(4.3)	0.5	39.9
Net cash flows provided by operating activities	1,200.5	1,772.9	(734.0)	2,239.4	1,468.7	(1,479.9)	2,228.2
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(81.8)	(2,698.1)	--	(2,779.9)	--	--	(2,779.9)
Proceeds from asset sales	0.1	440.4	--	440.5	--	--	440.5
Other investing activities	(2,004.1)	(16.6)	2,021.5	0.8	(71.2)	71.2	0.8
Cash used in investing activities	(2,085.8)	(2,274.3)	2,021.5	(2,338.6)	(71.2)	71.2	(2,338.6)
Financing activities:							
Borrowings under debt agreements	6,005.1	560.0	--	6,565.1	--	--	6,565.1
Repayments of debt	(3,641.0)	(1,348.3)	--	(4,989.3)	--	--	(4,989.3)
Cash distributions paid to partners	(1,480.2)	(679.0)	679.0	(1,480.2)	(1,459.7)	1,480.2	(1,459.7)
Cash distributions paid to noncontrolling interests	--	(103.7)	51.7	(52.0)	--	--	(52.0)
Cash contributions from noncontrolling interests	--	724.9	(719.9)	5.0	--	(0.3)	4.7
Net cash proceeds from issuance of common units	--	--	--	--	67.1	--	67.1
Cash contributions from owners	71.2	1,323.5	(1,323.5)	71.2	--	(71.2)	--
Other financing activities	(57.0)	--	--	(57.0)	(4.9)	--	(61.9)
Cash provided by (used in) financing activities	898.1	477.4	(1,312.7)	62.8	(1,397.5)	1,408.7	74.0
Net change in cash and cash equivalents	12.8	(24.0)	(25.2)	(36.4)	--	--	(36.4)
Cash and cash equivalents, January 1	0.5	67.9	(2.9)	65.5	--	--	65.5
Cash and cash equivalents, September 30	$ 13.3	$ 43.9	$ (28.1)	$ 29.1	$ --	$ --	$ 29.1

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

For the three and nine months ended September 30, 2012 and 2011.

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, 2011, as filed on February 29, 2012 (the "2011 Form 10-K"). Our financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States ("U.S.").

Key References Used in this Quarterly Report

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

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

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

In April 2011, we, our general partner, EPD MergerCo LLC ("Duncan MergerCo," our wholly owned subsidiary), Duncan Energy Partners L.P. ("Duncan Energy Partners") and DEP Holdings, LLC ("DEP GP," the general partner of Duncan Energy Partners) entered into a definitive merger agreement (the "Duncan Merger Agreement"). In September 2011, the Duncan Merger Agreement was approved by the unitholders of Duncan Energy Partners and the merger of Duncan MergerCo with and into Duncan Energy Partners and related transactions were completed, with Duncan Energy Partners surviving such merger as our wholly owned subsidiary (collectively, we refer to these transactions as the "Duncan Merger"). Since we historically consolidated Duncan Energy Partners for financial reporting purposes, the Duncan Merger did not change the basis of presentation of our historical financial statements. For additional information regarding the Duncan Merger, see Note 1 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

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

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries. We sold our remaining limited partner interests in Energy Transfer Equity in April 2012.

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 discussion contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "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 Part I, Item 1A "Risk Factors" included in our 2011 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 only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

Overview of Business

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO and are now a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and petrochemicals. Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the U.S., Canada and the Gulf of Mexico with domestic consumers and international markets. Our assets include approximately 50,700 miles of onshore and offshore pipelines; 190 MMBbls of storage capacity for NGLs, crude oil, refined products and petrochemicals; and 14 Bcf of working natural gas storage capacity.

Our integrated midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals; crude oil and refined products transportation, storage, and terminals; offshore production platforms; petrochemical transportation and services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico.

We have 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 (see "Liquidity and Capital Resources – Liquidation of Investment in Energy Transfer Equity" within this Item 2).

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.

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.

Significant Recent Developments

The following information highlights significant commercial and operational developments since January 1, 2012 through the date of this filing (November 9, 2012). For information regarding recent offerings of our equity and debt securities, see "Liquidity and Capital Resources" within this Item 2.

Enterprise Begins Service at ECHO Crude Oil Terminal

In November 2012, the initial phase of our Enterprise Crude Houston (or "ECHO") storage terminal located in Harris County, Texas was completed and started receiving deliveries of crude oil. The first three tanks placed in service total 750 MBPD of storage capacity. The next phase of the ECHO terminal expansion includes the addition of up to 900 MBPD of storage capacity, which could be in service as early as the first quarter of 2014. When completed, we estimate that the ECHO terminal could have up to 6.0 MMBbls of crude oil storage capacity.

Formation of Eagle Ford Crude Oil Pipeline Joint Venture with Plains

In August 2012, we announced the formation of a 50/50 joint venture, Eagle Ford Pipeline LLC, with Plains All American Pipeline, L.P. ("Plains") to provide crude oil pipeline services to producers in South Texas. The arrangement provides for Enterprise and Plains to consolidate certain segments of previously announced pipeline projects servicing the Eagle Ford Shale supply basin. The joint venture pipeline system is supported by long-term commitments from producers totaling up to 210 MBPD of crude oil. This joint venture is expected to provide shippers with increased market flexibility and enable Enterprise and Plains to optimize their respective capital investments in the area.

The joint venture will include a 140–mile crude oil and condensate line extending from Gardendale, Texas in LaSalle County to Three Rivers, Texas in Live Oak County and continuing on to Corpus Christi, Texas, and a newly constructed 35-mile pipeline segment from Three Rivers to our Lyssy, Texas station in Wilson County. The system, which is currently under construction, is expected to have a capacity of 350 MBPD and will include a marine terminal facility at Corpus Christi and 1.8 MMBbls of operational storage capacity across the system. Segments of the new pipeline system are expected to be placed into service in the second quarter of 2013, with the balance of the system expected to be placed into service in the first quarter of 2014. Plains will serve as operator of the joint venture's pipeline system.

At Lyssy, the joint venture pipeline will interconnect with the Eagle Ford expansion of our South Texas Crude Oil Pipeline System, which commenced operations in June 2012 (see below). Our South Texas Crude Oil Pipeline System is not part of the new joint venture's pipeline system.

Plans to Build World-Scale Propane Dehydrogenation Unit

In June 2012, we announced plans to build one of the world's largest propane dehydrogenation ("PDH") units, with capacity to produce up to 1.65 billion pounds per year, which equates to approximately 750,000 metric tons per year or 25 MBPD, of polymer grade propylene. The PDH facility is expected to consume up to 35 MBPD of propane as feedstock and be located in southeast Texas along the Gulf Coast. The facility, which is supported by long-term, fee-based contracts, is expected to begin commercial operations during the third quarter of 2015 and integrate operationally with our other NGL and propylene facilities.

Eagle Ford Expansion of Our South Texas Crude Oil Pipeline System Commences Operations

In June 2012, we announced that the Eagle Ford expansion of our South Texas Crude Oil Pipeline System commenced operations. This pipeline expansion, which has a crude oil transportation capacity of 350 MBPD, allows us to serve growing production areas in the Eagle Ford Shale supply basin. The new pipeline originates at Lyssy, Texas and extends 147 miles to Sealy, Texas and includes 2.4 MMBbls of crude oil storage, including 0.6 MMBbls at Lyssy, 0.2 MMBbls at Milton, Texas, 0.4 MMBbls at Marshall, Texas and 1.2 MMBbls at Sealy. Crude oil supplies arriving at Sealy on the new pipeline are being delivered to Houston area refiners through affiliate and third party owned pipelines. In addition, shippers will have access to our new ECHO crude oil storage terminal.

Seaway Pipeline Makes First Delivery of Crude Oil to Texas Gulf Coast

In June 2012, we and Enbridge Inc. ("Enbridge") announced that the Seaway Pipeline made its first delivery of crude oil to the Texas Gulf Coast. The arrival marks the first southbound delivery of crude oil by pipeline from the oversupplied Cushing hub, and gives producers access to all of the major refineries in the Greater Houston area and Texas City. Additional pump station additions and modifications, which are expected to be completed by the first quarter of 2013, will increase throughput capacity on the Seaway Pipeline.

In March 2012, we secured capacity commitments from shippers to proceed with an additional expansion of the Seaway Pipeline. This expansion project entails the construction of a 512-mile, 30-inch diameter parallel pipeline mostly along the existing route of the Seaway Pipeline. It is anticipated that the new pipeline would commence operations during the first quarter of 2014. Once this expansion is completed, the total anticipated capacity of the Seaway Pipeline system would be approximately 850 MBPD.

The Seaway Pipeline delivers crude oil from Cushing into the Houston, Texas market utilizing affiliate and third party pipelines. Seaway Crude Oil Pipeline Company ("Seaway") is constructing a 65-mile pipeline that will link its pipeline system to our ECHO crude oil storage terminal. Completion of this pipeline segment is expected in 2013. In addition, Seaway plans to build an 85-mile pipeline from our ECHO terminal to the Port Arthur/Beaumont, Texas refining center that would provide shippers access to the region's heavy oil refining capabilities. Completion of this pipeline segment is expected in early 2014.

Yoakum Natural Gas Processing Plant Begins Operations in Eagle Ford Shale

In May 2012, we announced that the first phase (or "train") of our new cryogenic natural gas processing plant at Yoakum, Texas commenced operations. The second train commenced operations in late August 2012. In the aggregate, these two processing trains are processing up to a combined 700 MMcf/d of natural gas and extracting 90 MBPD of NGLs. The third and final train at the Yoakum facility, which is similar in size to the first two trains, is expected to be completed during the first quarter of 2013.

In April 2012, we completed a 65-mile residue natural gas pipeline linking the Yoakum plant to our Wilson natural gas storage facility. Additionally, we completed construction of 169 miles of pipelines that will transport mixed NGLs from the Yoakum plant to our NGL fractionation and storage complex at Mont Belvieu, Texas.

Plans to Construct Front Range Pipeline

In April 2012, we, along with WGR Asset Holding Company LLC, an affiliate of Anadarko Petroleum Corporation, and DCP Midstream Front Range LLC formed a new joint venture, Front Range, to design and construct a new NGL pipeline that will originate in the Denver-Julesburg Basin (the "DJ Basin") in Weld County, Colorado and extend 435 miles to Skellytown in Carson County, Texas. Each party holds a one-third ownership interest in the joint venture. The Front Range Pipeline, with connections to our Mid-America Pipeline System and the Texas Express Pipeline, will provide producers in the DJ Basin with access to the Gulf Coast, the largest NGL market in the U.S. Initial capacity on the Front Range

Pipeline will be 150 MBPD, which can be readily expanded to 230 MBPD. We will construct and operate the pipeline, which is expected to begin service in the fourth quarter of 2013.

Expansion of NGL Fractionation Capacity at Mont Belvieu

In March 2012, we announced plans to construct two additional NGL fractionators at our Mont Belvieu, Texas complex (NGL fractionators seven and eight) that are expected to provide us with 170 MBPD of incremental NGL fractionation capacity. The two new fractionation units (each with 85 MBPD of expected capacity) are forecast to commence operations during the fourth quarter of 2013 and support the continued growth of NGL production from resource basins such as the Eagle Ford Shale in Texas and various production areas in the Rocky Mountains.

In early November 2012, construction of our sixth NGL fractionator at Mont Belvieu was completed and it commenced operations. This plant is supported by long-term customer commitments and has an expected capacity of 85 MBPD. Completion of this plant increased the total NGL fractionation capacity at our Mont Belvieu complex to 485 MBPD. Once NGL fractionators seven and eight are constructed and placed in service, our total gross NGL fractionation capacity at Mont Belvieu (then eight units in total) would approximate 650 MBPD. At that time, our system-wide fractionation capacity is expected to exceed 1.0 MMBPD.

Development of Our ATEX Express Long-Haul Ethane Pipeline

In January 2012, we secured sufficient transportation commitments to support development of our 1,230-mile Appalachia-to-Texas pipeline (the "ATEX Express"), which will transport growing ethane production from the Marcellus and Utica Shale producing areas to the U.S. Gulf Coast.

Demand for ethane feedstock over more expensive crude oil-based derivatives within the Gulf Coast petrochemical market has reached over 1 MMBPD. Several petrochemical companies have made announcements to modify, expand or build new facilities that would use ethane as a feedstock. As currently designed, the ATEX Express will have the capacity to transport up to 190 MBPD of ethane from Appalachian production areas to our storage and distribution assets in southeast Texas.

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

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

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

Results of Operations

Summarized Consolidated Income Statement Data (Unaudited)

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Revenues	$ 10,468.7	$ 11,327.1	$ 31,511.0	$ 32,727.3
Costs and expenses:				
Operating costs and expenses:				
Cost of sales	8,794.0	9,787.6	26,655.0	28,397.2
Other operating costs and expenses	556.1	575.3	1,672.9	1,595.6
Depreciation, amortization and accretion	269.2	238.3	785.1	702.4
Losses (gains) related to asset sales	(0.3)	17.6	(4.1)	(0.6)
Gains from sale of ownership interests in equity-method unconsolidated affiliate – Energy Transfer Equity	--	(19.4)	--	(24.8)
Gains related to property damage insurance recoveries	(2.3)	--	(30.0)	--
Non-cash asset impairment charges	43.1	5.2	57.6	5.2
Total operating costs and expenses	9,659.8	10,604.6	29,136.5	30,675.0
General and administrative costs	41.4	50.0	130.2	138.3
Total costs and expenses	9,701.2	10,654.6	29,266.7	30,813.3
Equity in income of unconsolidated affiliates	21.0	8.6	42.2	35.9
Operating income	788.5	681.1	2,286.5	1,949.9
Interest expense	(199.7)	(189.0)	(572.8)	(561.1)
Other, net	1.5	(1.0)	73.4	(0.2)
Benefit from (provision for) income taxes	(2.4)	(11.6)	23.5	(26.1)
Net income	587.9	479.5	1,810.6	1,362.5
Net income attributable to noncontrolling interests	(1.1)	(8.1)	(6.2)	(36.7)
Net income attributable to limited partners	$ 586.8	$ 471.4	$ 1,804.4	$ 1,325.8

Consolidated Revenues by Business Segment

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

	For the Three Months Ended September 30, 2012	For the Three Months Ended September 30, 2011	For the Nine Months Ended September 30, 2012	For the Nine Months Ended September 30, 2011
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 3,151.9	$ 4,164.9	$ 10,401.1	$ 12,054.8
Midstream services	239.9	253.6	677.7	657.4
Total	3,391.8	4,418.5	11,078.8	12,712.2
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	608.2	704.7	1,691.6	2,136.9
Midstream services	238.3	218.0	708.9	629.7
Total	846.5	922.7	2,400.5	2,766.6
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	4,471.8	3,929.8	13,093.4	11,535.9
Midstream services	33.4	27.3	74.1	73.4
Total	4,505.2	3,957.1	13,167.5	11,609.3
Offshore Pipelines & Services:				
Sales of natural gas	0.2	0.3	0.3	0.9
Sales of crude oil	3.1	1.3	4.5	7.1
Midstream services	41.9	58.5	145.5	180.2
Total	45.2	60.1	150.3	188.2
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	1,498.9	1,767.2	4,166.9	4,868.7
Midstream services	181.1	201.5	547.0	582.3
Total	1,680.0	1,968.7	4,713.9	5,451.0
Total consolidated revenues	$ 10,468.7	$ 11,327.1	$ 31,511.0	$ 32,727.3

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 presented:

	Natural Gas, $/MMBtu (1)	Ethane, $/gallon (2)	Propane, $/gallon (2)	Normal Butane, $/gallon (2)	Isobutane, $/gallon (2)	Natural Gasoline, $/gallon (2)	Polymer Grade Propylene, $/pound (3)	Refinery Grade Propylene, $/pound (3)	Crude Oil, $/barrel (4)
2011									
1st Quarter	$ 4.11	$ 0.66	$ 1.37	$ 1.75	$ 1.85	$ 2.27	$ 0.76	$ 0.68	$ 94.10
2nd Quarter	$ 4.32	$ 0.78	$ 1.49	$ 1.87	$ 2.02	$ 2.48	$ 0.89	$ 0.79	$ 102.56
3rd Quarter	$ 4.20	$ 0.78	$ 1.54	$ 1.88	$ 2.09	$ 2.37	$ 0.78	$ 0.67	$ 89.76
4th Quarter	$ 3.54	$ 0.86	$ 1.44	$ 1.89	$ 2.26	$ 2.24	$ 0.59	$ 0.44	$ 94.06
2011 Averages	$ 4.04	$ 0.77	$ 1.46	$ 1.85	$ 2.06	$ 2.34	$ 0.76	$ 0.64	$ 95.12
2012									
1st Quarter	$ 2.72	$ 0.56	$ 1.26	$ 1.93	$ 2.04	$ 2.39	$ 0.69	$ 0.60	$ 102.93
2nd Quarter	$ 2.21	$ 0.40	$ 0.98	$ 1.62	$ 1.75	$ 2.05	$ 0.66	$ 0.51	$ 93.49
3rd Quarter	$ 2.80	$ 0.34	$ 0.89	$ 1.44	$ 1.62	$ 2.01	$ 0.51	$ 0.37	$ 92.22
2012 Averages	$ 2.58	$ 0.44	$ 1.04	$ 1.66	$ 1.80	$ 2.15	$ 0.62	$ 0.49	$ 96.21

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

Period-to-period fluctuations in our consolidated revenues and cost of sales amounts are explained in large part by changes in energy commodity prices, especially those for NGLs, natural gas and crude oil. Energy commodity prices fluctuate for a variety of reasons, including supply and demand imbalances and geopolitical tensions. With the exception of crude oil, energy commodity prices during the nine months ended September 30, 2012 have been lower when compared to the same period in 2011. For example:

§ 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 $1.01 per gallon during the third quarter of 2012 versus $1.50 per gallon during the third quarter of 2011 – a 33% quarter-to-quarter decrease. The weighted-average indicative market price for NGLs for the first nine months of 2012 was $1.15 per gallon compared to $1.45 per gallon during the first nine months of 2011 – a 21% period-to-period decrease.

§ The market price of natural gas (as measured at the Henry Hub in Louisiana) averaged $2.80 per MMBtu during the third quarter of 2012 versus $4.20 per MMBtu during the third quarter of 2011 – a 33% quarter-to-quarter decrease. The Henry Hub market price of natural gas for the first nine months of 2012 averaged $2.58 per MMBtu compared to $4.21 per MMBtu during the first nine months of 2011 – a 39% period-to-period decrease.

§ The market price of crude oil (as measured on the NYMEX) averaged $92.22 per barrel during the third quarter of 2012 compared to $89.76 per barrel during the third quarter of 2011 – a 3% quarter-to-quarter increase. The NYMEX market price of crude oil for the first nine months of 2012 averaged $96.21 per barrel compared to $95.48 per barrel during the first nine months of 2011.

A decrease in our consolidated marketing revenues due to lower commodity energy sales prices may not generate a decrease in gross operating margin or cash available for distributions, since corresponding 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 prices.

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 Item 3 of this quarterly report for information regarding our commodity hedging activities.

Consolidated Income Statement Highlights

The following information highlights significant changes in our quarter-to-quarter and period-to-period income statement amounts and the primary drivers of such changes.

Revenues for the third quarter of 2012 decreased $858.4 million compared to the third quarter of 2011. NGL, natural gas and petrochemical marketing revenues for the third quarter of 2012 decreased $1.38 billion primarily due to lower energy commodity prices in 2012. This quarter-to-quarter decrease was partially offset by a $543.8 million quarter-to-quarter increase in crude oil sales revenues primarily due to higher sales volumes. For the first nine months of 2012, revenues decreased $1.22 billion when compared to the same period in 2011. NGL, natural gas and petrochemical marketing revenues for the nine months ended September 30, 2012 decreased $2.8 billion primarily due to lower energy commodity prices in 2012. This period-to-period decrease was partially offset by a $1.55 billion period-to-period increase in crude oil sales revenues primarily due to higher sales volumes.

Operating costs and expenses for the third quarter of 2012 decreased $944.8 million compared to the third quarter of 2011 primarily due to lower cost of sales amounts attributable to the decrease in energy commodity prices. The cost of sales associated with our NGL, natural gas, petrochemical and refined products marketing activities decreased $1.46 billion quarter-to-quarter, which was partially offset by a $463.5 million increase in the cost of sales associated with higher crude oil sales volumes. For the first nine months of 2012, operating costs and expenses decreased $1.54 billion when compared to the same period in 2011. The cost of sales associated with our NGL, natural gas and petrochemical marketing activities decreased $3.08 billion period-to-period primarily due to lower energy commodity prices. This period-to-period decrease was partially offset by a $1.34 billion increase in the cost of sales associated with increased crude oil sales volumes.

During the three and nine months ended September 30, 2012, we collected $2.3 million and $30.0 million, respectively, of nonrefundable cash proceeds from insurance carriers that we recognized as a gain within operating costs and expenses. These proceeds relate to property damage claims we made in connection with the February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. For additional information regarding our insurance matters, see "Other Items – Insurance Matters" within this Item 2.

General and administrative costs for the third quarter of 2012 decreased $8.6 million compared to the third quarter of 2011 primarily due to the third quarter of 2011 including $10.0 million of transaction expenses related to the Duncan Merger. For the nine months ended September 30, 2012, general and administrative costs decreased $8.1 million compared to the same period in 2011. The nine-month period ending September 30, 2011 included $11.5 million of transaction expenses related to the Duncan Merger.

Interest expense for the third quarter of 2012 increased $10.7 million compared to the third quarter of 2011 primarily due to an increase in our average debt principal balance outstanding and lower capitalized interest, partially offset by the write-off of $5.2 million of unamortized debt issuance costs that occurred in 2011 in connection with the Duncan Merger. Our average debt principal balance increased to $15.7 billion in the third quarter of 2012 compared to $14.84 billion in the third quarter of 2011. On a weighted-average basis, interest rates charged on our consolidated debt during the third quarter of 2012 were essentially unchanged with respect to those charged during the third quarter of 2011. Interest costs capitalized in connection with our construction projects decreased $6.8 million quarter-to-quarter.

Interest expense for the nine months ended September 30, 2012 increased $11.7 million period-to-period primarily due to an increase in our average debt principal balance outstanding. On a weighted-average basis, interest rates charged on our consolidated debt during the first nine months of 2012 were essentially unchanged with respect to those charged during the same period in 2011. Our average debt principal balance for the first nine months of 2012 was $15.04 billion compared to $14.44 billion for the same period in 2011. Interest costs capitalized in connection with our construction projects increased $11.3 million period-to-period.

We recognized a net income tax benefit of $23.5 million for the first nine months of 2012 compared to a $26.1 million provision for income taxes recognized for the first nine months of 2011. The $49.6 million period-to-period change in income taxes is primarily due to a $46.5 million benefit related to the conversion of certain of our subsidiaries to limited liability companies during the first quarter of 2012. The provision for income taxes for the third quarter of 2012 decreased $9.2 million quarter-to-quarter primarily due to reduced liability accruals for the Texas Margin Tax.

Results for the first nine months of 2012 include $68.8 million of gains recorded in connection with the liquidation of our investment in Energy Transfer Equity, which was completed in April 2012. Results for the first nine months of 2011 include $24.8 million of gains recorded in connection with the sale of Energy Transfer Equity common units, of which $19.4 million are attributable to the third quarter of 2011. For additional information regarding these sales, see "Liquidity and Capital Resources – Liquidation of Investment in Energy Transfer Equity" within this Item 2.

Business Segment Highlights

Total segment gross operating margin was $1.14 billion for the third quarter of 2012 compared to $972.8 million for the third quarter of 2011. With respect to the nine months ended September 30, 2012, total segment gross operating margin was $3.23 billion versus $2.77 billion for the same period in 2011.

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

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. For information regarding this financial metric, see "Other Items – Use of Non-GAAP Financial Measures" within this Item 2.

All activities included in our former sixth reportable business segment, Other Investments, ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our previously held investment in Energy Transfer Equity. Our equity earnings from this investment were $2.4 million and $11.3 million for the nine months ended September 30, 2012 and 2011, respectively, and $2.3 million for the third quarter of 2011.

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 September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Segment gross operating margin:				
Natural gas processing and related NGL marketing activities	$ 352.4	$ 348.0	$ 1,112.9	$ 928.9
NGL pipelines and related storage	195.0	145.9	521.2	468.4
NGL fractionation	68.4	53.7	202.4	152.4
Total	$ 615.8	$ 547.6	$ 1,836.5	$ 1,549.7
Selected volumetric data:				
NGL transportation volumes (MBPD)	2,473	2,241	2,440	2,286
NGL fractionation volumes (MBPD)	653	554	643	557
Equity NGL production (MBPD) (1)	99	114	102	117
Fee-based natural gas processing (MMcf/d) (2)	4,462	3,813	4,277	3,733

(1) Represents the NGL volumes we earn and take title to in connection with our processing activities. In general, equity NGL production decreased in 2012 compared to 2011 due to reduced ethane recoveries associated with the weakness in natural gas processing margins resulting from lower NGL prices.
(2) Volumes reported correspond to the revenue streams earned by our gas plants. The increase in fee-based processing volumes is primarily due to (i) the start-up of our Yoakum gas plant in May 2012 and (ii) changes in processing agreements whereby producers are electing to process more of their natural gas on a fee basis in order to retain NGLs extracted from their natural gas streams, which, in turn, also lowers our equity NGL production.

Natural gas processing and related NGL marketing activities

Gross operating margin from our natural gas processing and related NGL marketing activities for the third quarter of 2012 increased $4.4 million compared to the third quarter of 2011 primarily due to improved results from our NGL marketing activities and South Texas gas processing plants partially offset by lower gross operating margins attributable to our Louisiana, Wyoming, New Mexico and Colorado gas processing plants. Gross operating margin from our NGL marketing activities increased $47.7 million quarter-to-quarter primarily due to higher product sales margins. Our South Texas natural gas processing plants posted a $23.7 million quarter-to-quarter increase in gross operating margin primarily due to higher equity NGL and fee-based processing volumes and the start-up of our Yoakum gas processing plant, which commenced operations in May 2012.

Gross operating margin from our Louisiana gas plants decreased $7.2 million quarter-to-quarter primarily due to lower natural gas processing margins partially offset by higher processing fees. Gross operating margin from our Pioneer and Chaco gas plants decreased a combined $46.8 million quarter-to-quarter due to lower equity NGL production, which accounted for $24.2 million of the decrease, and lower natural gas processing margins, which accounted for most of the remaining decrease. Gross operating margin from our Meeker gas plant decreased $3.6 million quarter-to-quarter. Including the impact of improved commodity hedging results, processing margins at our Meeker gas plant increased $8.8 million quarter-to-quarter, which partially offset an estimated $15.5 million reduction in gross operating margin attributable to lower equity NGL volumes.

With respect to the nine months ended September 30, 2012, gross operating margin from our natural gas processing and related NGL marketing activities increased $184.0 million when compared to the same nine month period in 2011. Gross operating margin from our NGL marketing activities for the first nine months of 2012 increased $145.1 million over the same period in 2011 primarily due to higher sales margins. Our South Texas gas plants posted a $36.5 million period-to-period increase in gross operating margin primarily due to higher equity NGL and fee-based processing volumes, including those attributable to the new Yoakum gas plant. Gross operating margin from our Rocky Mountains gas plants for 2012 includes a one-time $20.0 million gain related to a vendor settlement. In addition, gross operating margin from our Meeker gas plant increased $52.9 million period-to-period primarily due to the favorable impact of our commodity hedging activities on the facility's processing margins during 2012. Gross operating margin from our Pioneer and Chaco gas plants decreased $46.0 million period-to-period primarily due to lower equity NGL production. Lastly, gross operating margin from our Louisiana and East Texas gas plants decreased $16.3 million period-to-period primarily due to lower equity NGL production and natural gas processing margins.

NGL pipelines and related storage

Gross operating margin from our NGL pipelines and related storage business for the third quarter of 2012 increased $49.1 million compared to third quarter of 2011. Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased $14.9 million quarter-to-quarter primarily due to an increase in system-wide tariffs that went into effect in July 2012 and higher terminaling fees. Gross operating margin from our Mont Belvieu NGL storage business and Houston Ship Channel export terminal increased a combined $15.7 million for the third quarter of 2012 primarily due to higher storage and NGL export volumes. Collectively, gross operating margin from our South Texas NGL pipelines, including the new Eagle Ford NGL Pipeline placed into service in April 2012, increased $15.7 million quarter-to-quarter primarily due to higher volumes associated with Eagle Ford Shale production.

With respect to the nine months ended September 30, 2012, gross operating margin from our NGL pipelines and related storage business increased $52.8 million when compared with the same nine month period in 2011. Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased $36.0 million period-to-period primarily due to an increase in system-wide tariffs and higher terminaling fees. Gross operating margin from our Mont Belvieu NGL storage business and Houston Ship Channel export terminal increased a combined $33.4 million for the first nine months of 2012 primarily due to higher storage and export volumes.

The foregoing year-to-date increases in gross operating margin from our NGL pipelines and related storage business were partially offset by several factors. Gross operating margin from our Dixie Pipeline and related NGL terminals decreased $7.6 million period-to-period primarily due to higher pipeline integrity costs and lower transportation volumes attributable to warmer weather and maintenance-related downtime during the first six months of 2012. In addition, gross operating margin decreased $19.7 million period-to-period due to the impact of net operational measurement gains during the first nine months of 2011 that did not reoccur during the first nine months of 2012.

NGL fractionation

Gross operating margin from NGL fractionation for the third quarter of 2012 increased $14.7 million compared to the third quarter of 2011 primarily due to higher fractionation volumes at our Mont Belvieu complex. During the fourth quarter of 2011, we placed into service a fifth NGL fractionator at our

Mont Belvieu complex, which added more than 75 MBPD of NGL fractionation capacity at this key industry hub.

With respect to the nine months ended September 30, 2012, gross operating margin from NGL fractionation increased $50.0 million compared to the same period in 2011 primarily due to higher fractionation volumes at our Mont Belvieu complex.

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 September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Segment gross operating margin	$ 183.5	$ 156.0	$ 565.5	$ 476.3
Selected volumetric data:				
Natural gas transportation volumes (BBtus/d)	14,182	12,379	13,703	11,989

Gross operating margin from our onshore natural gas pipelines and services business increased $27.5 million for the third quarter of 2012 compared to the third quarter of 2011. Gross operating margin from our Acadian Gas System increased $46.4 million quarter-to-quarter primarily due to contributions from our Haynesville Extension pipeline. The Haynesville Extension of our Acadian Gas System commenced operations in November 2011 and transported 1.5 TBtus/d of natural gas during the third quarter of 2012. Gross operating margin from our Texas natural gas pipelines and related storage assets increased $13.5 million quarter-to-quarter primarily due to higher firm capacity reservation revenues on the Texas Intrastate System. Increased natural gas production volumes from the Eagle Ford Shale supply basin resulted in stronger demand for our natural gas transportation services on the Texas Intrastate System during the third quarter of 2012 compared to the third quarter of 2011.

The foregoing quarter-to-quarter increases in gross operating margin from our natural gas pipelines were partially offset by several factors. Gross operating margin from our New Mexico gathering systems decreased a combined $11.2 million quarter-to-quarter primarily due to lower gathering and related fees on our San Juan Gathering System, which accounted for $5.6 million of the quarter-to-quarter decrease, and lower throughput volumes on both the San Juan and Carlsbad systems. Gathering fees on our San Juan system are impacted by changes in regional natural gas prices, which decreased 35% quarter-to-quarter. Gross operating margin from our Jonah Gathering System decreased $3.4 million quarter-to-quarter primarily due to lower throughput volumes, which decreased 16% quarter-to-quarter. Gross operating margin from our natural gas marketing activities decreased $6.1 million quarter-to-quarter primarily due to lower sales margins. Lastly, gross operating margin from our natural gas storage business decreased $9.3 million quarter-to-quarter due to the sale of our Mississippi natural gas storage facilities in December 2011.

With respect to the nine months ended September 30, 2012, gross operating margin from onshore natural gas pipelines and services increased $89.2 million compared to the same period in 2011. Gross operating margin from our Acadian Gas System increased $128.2 million period-to-period primarily due to contributions from our Haynesville Extension pipeline. Gross operating margin from our Texas natural gas pipelines and related storage assets increased $65.7 million period-to-period primarily due to higher firm capacity reservation revenues on the Texas Intrastate System attributable to Eagle Ford Shale production. Gross operating margin from our San Juan Gathering System decreased $30.0 million period-to-period primarily due to lower gathering and related fees. Gross operating margin from our natural gas marketing activities decreased $20.5 million period-to-period primarily due to lower sales margins. Gross operating margin from our Jonah Gathering System decreased $12.0 million period-to-period primarily due to lower throughput volumes. Lastly, gross operating margin decreased $33.3 million period-to-period due to the sale of our Mississippi natural gas storage business in December 2011 and the sale of a gas gathering system in Alabama in August 2011.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Segment gross operating margin	$ 117.6	$ 67.4	$ 252.7	$ 167.0
Selected volumetric data:				
Crude oil transportation volumes (MBPD)	820	725	751	678

Gross operating margin from our onshore crude oil pipelines and services business increased $50.2 million for the third quarter of 2012 compared to the third quarter of 2011. Gross operating margin from our South Texas Crude Oil Pipeline System increased $19.5 million quarter-to-quarter primarily due to a 75 MBPD increase in throughput volumes during the third quarter of 2012. The increase in throughput volumes for our South Texas system is primarily due to the Eagle Ford Expansion pipeline being placed into service in June 2012. Next, equity earnings from our investment in Seaway increased $17.5 million quarter-to-quarter primarily due to a 117 MBPD increase in transportation volumes (58 MBPD net to our interest) attributable to completion of the Seaway Pipeline reversal project in May 2012. Lastly, gross operating margin from our crude oil marketing and related activities increased $13.8 million quarter-to-quarter primarily due to higher sales margins, which accounted for $7.5 million of the increase, and sales volumes. Our crude oil marketing activities continue to benefit from positive marketing opportunities associated with increased crude oil production volumes from supply basins in the Eagle Ford Shale, Barnett Shale, West Texas and Rocky Mountains.

With respect to the nine months ended September 30, 2012, gross operating margin from onshore crude oil pipelines and services increased $85.7 million period-to-period. Gross operating margin from our crude oil marketing and related activities increased $34.6 million period-to-period primarily due to higher sales volumes, which accounted for $19.6 million of the increase, and sales margins, which accounted for the remaining increase. Gross operating margin from our South Texas Crude Oil Pipeline System increased $28.5 million period-to-period primarily due to higher volumes attributable to the Eagle Ford Expansion pipeline. Equity earnings from our investment in Seaway increased $23.7 million period-to-period primarily due to the Seaway Pipeline commencing the southbound delivery of crude oil during the second quarter of 2012.

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 September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Segment gross operating margin	$ 40.6	$ 53.9	$ 131.0	$ 168.6
Selected volumetric data: (1)				
Natural gas transportation volumes (BBtus/d)	760	1,009	876	1,067
Crude oil transportation volumes (MBPD)	293	259	289	279
Platform natural gas processing (MMcf/d)	238	376	306	412
Platform crude oil processing (MBPD)	14	15	17	17

(1) The Offshore Pipelines & Services segment continues to be adversely impacted by lower volumes attributable to the federal offshore drilling moratorium in 2010 and 2011. In recent months, however, the rig count and drilling activity in the Gulf of Mexico is approaching pre-moratorium levels.

Gross operating margin from our offshore pipelines and services business decreased $13.3 million for the third quarter of 2012 compared to the third quarter of 2011. Collectively, gross operating margin from our Independence Hub platform and Trail pipeline decreased $20.8 million quarter-to-quarter primarily due to lower throughput volumes and platform demand fee revenues during the third quarter of 2012 versus the third quarter of 2011. Producers connected to our Independence Hub platform paid us $54.6 million of demand fees annually for five years beginning in March 2007 until that period expired in

March 2012. Expiration of these contractual demand fees resulted in a $13.6 million quarter-to-quarter decrease in gross operating margin. Net to our interest, natural gas processing volumes on the Independence Hub platform decreased 138 MMcf/d quarter-to-quarter.

Collectively, gross operating margin from the remainder of the assets in this segment increased $7.5 million quarter-to-quarter primarily due to natural gas and crude oil production from the Caesar/Tonga development in the Green Canyon area of the Gulf of Mexico and lower insurance premium costs. Production from the Caesar/Tonga development commenced in March 2012 and resulted in a quarter-to-quarter increase in transportation volumes on our Anaconda Natural Gas Pipeline and Constitution and Poseidon Crude Oil Pipelines. Insurance premium costs are lower period-to-period primarily due to the elimination of windstorm coverage for our offshore assets during the current policy period. For a discussion of insurance-related matters, see "Other Items – Insurance Matters" within this Item 2.

With respect to the nine months ended September 30, 2012, gross operating margin from offshore pipelines and services decreased $37.6 million period-to-period. Collectively, gross operating margin from our Independence Hub platform and Trail pipeline decreased $48.3 million period-to-period primarily due to lower throughput volumes and platform demand fee revenues during the first nine months of 2012 versus the first nine months of 2011. Expiration of these contractual demand fees during the first nine months of 2012 resulted in a $31.2 million period-to-period decrease in gross operating margin. Net to our interest, natural gas processing volumes on the Independence Hub platform decreased 109 MMcf/d period-to-period.

Collectively, gross operating margin from our Anaconda Natural Gas Pipelines and Constitution and Poseidon Crude Oil Pipelines increased $17.0 million period-to-period primarily due to natural gas and crude oil production from the Caesar/Tonga development in the Green Canyon area of the Gulf of Mexico. This increase was partially offset by a $4.7 million period-to-period decrease in gross operating margin from our Cameron Highway Oil Pipeline due to downtime associated with certain producer wells in early 2012.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Segment gross operating margin:				
Propylene fractionation and related activities	$ 55.6	$ 37.3	$ 159.5	$ 117.3
Butane isomerization	25.5	32.7	71.2	93.1
Octane enhancement and related plant operations	50.1	38.7	87.7	82.0
Refined products pipelines and related activities	7.0	21.5	37.2	62.0
Marine transportation and other	43.9	15.4	81.6	43.4
Total	$ 182.1	$ 145.6	$ 437.2	$ 397.8
Selected volumetric data:				
Propylene fractionation volumes (MBPD)	73	74	73	72
Butane isomerization volumes (MBPD)	104	105	95	99
Octane additive and associated plant production volumes (MBPD)	19	18	16	17
Transportation volumes, primarily refined products and petrochemicals (MBPD)	713	825	677	792

Propylene fractionation and related activities

Gross operating margin from our propylene fractionation and related petrochemical marketing activities increased $18.3 million for the third quarter of 2012 compared to the third quarter of 2011 primarily due to higher propylene sales margins during the third quarter of 2012. With respect to the nine months ended September 30, 2012, gross operating margin increased $42.2 million compared to the same period in 2011 primarily due to higher propylene sales margins during the first nine months of 2012.

Butane isomerization

Gross operating margin from butane isomerization decreased $7.2 million for the third quarter of 2012 compared to the third quarter of 2011. Likewise, gross operating margin for the first nine months of 2012 declined $21.9 million compared to the same period in 2011. Both the quarter-to-quarter and year-to-date decreases in gross operating margin are primarily due to lower isomerization volumes (and corresponding by-product production and sales) and processing fees. Isomerization volumes for 2012 were negatively impacted by extended downtime for maintenance at our octane enhancement facility (which utilizes high purity isobutane feedstock produced at our butane isomerization facility) during the first quarter of 2012. The decrease in by-product production and sales during the third quarter of 2012 accounted for $5.0 million of the $7.2 million quarter-to-quarter reduction in gross operating margin. Likewise, the decrease in by-product production and sales during the first nine months of 2012 accounted for $14.8 million of the $21.9 million period-to-period decrease in gross operating margin.

Octane enhancement and related plant operations

Gross operating margin from octane enhancement and related high purity isobutylene plant operations increased a combined $11.4 million quarter-to-quarter. This increase was primarily due to higher product sales margins during the third quarter of 2012. With respect to the nine months ended September 30, 2012, gross operating margin for these facilities increased $5.7 million compared to the same period in 2011. An estimated $29.0 million period-to-period increase attributable to higher product sales margins was partially offset by the combined effects of an estimated $12.9 million decrease due to lower sales volumes and $10.4 million in higher operating expenses (primarily catalyst and related costs) during the first nine months of 2012.

Refined products pipelines and related activities

Gross operating margin from refined products pipelines and related marketing activities decreased $14.5 million for the third quarter of 2012 compared to the third quarter of 2011 primarily due to a quarter-to-quarter 27 MBPD decrease in NGL volumes delivered to Northeast U.S. markets and a 59 MBPD decrease in refined products volumes delivered to Midwest U.S. markets. Gross operating margin for the nine months ended September 30, 2012 decreased $24.8 million compared to the same period in 2011 primarily for the same reasons.

In general, warmer weather during the first nine months of 2012 compared to the same period in 2011 resulted in lower demand for propane used as heating fuel, while shipments of refined products from the Gulf Coast to Midwest markets decreased as a result of lower prices for such products in Midwestern markets than in Gulf Coast markets.

Marine transportation and other

Gross operating margin from marine transportation and other segment services increased $28.5 million for the third quarter of 2012 compared to the third quarter of 2011. Likewise, gross operating margin increased $38.2 million for the first nine months of 2012 versus the same period in 2011. Results for the third quarter of 2012 and the first nine months of 2012 include a $24.0 million gain recorded in connection with a legal settlement. The remainder of the quarter-to-quarter and period-to-period increase in gross operating margin is primarily due to the combination of higher marine transportation fees and lower operating expenses associated with our fleet of marine vessels during 2012.

Liquidity and Capital Resources

At September 30, 2012, we had $3.43 billion of consolidated liquidity, which is defined as unrestricted cash on hand plus borrowing capacity available under EPO's $3.5 Billion Multi-Year Revolving Credit Facility. 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 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 "2010 Shelf") on file with the SEC. The 2010 Shelf allows Enterprise Products Partners L.P. and EPO (on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively.

Long-Term Debt

We had $15.92 billion of principal amounts outstanding under consolidated debt agreements at September 30, 2012. The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at September 30, 2012 for the next five years, and in total thereafter (dollars in millions):

		Scheduled Maturities of Debt					
	Total	Remainder of 2012	2013	2014	2015	2016	After 2016
Revolving Credit Facility	$ 85.0	$ --	$ --	$ --	$ --	$ 85.0	$ --
Senior Notes	14,300.0	--	1,200.0	1,150.0	1,300.0	750.0	9,900.0
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Total	$ 15,917.7	$ --	$ 1,200.0	$ 1,150.0	$ 1,300.0	$ 835.0	$ 11,432.7

In February 2012, EPO issued $750.0 million in principal amount of 30-year unsecured Senior Notes EE at 99.542% of their principal amount. Senior Notes EE have a fixed interest rate of 4.85% and mature on August 15, 2042. Net proceeds from the issuance of Senior Notes EE were used to repay amounts due upon the maturity of $490.5 million principal amount of EPO Senior Notes S due February 2012 and $9.5 million principal amount of TEPPCO Senior Notes due February 2012 and for general company purposes.

In August 2012, EPO issued $650.0 million in principal amount of 3-year unsecured Senior Notes FF at 99.941% of their principal amount and $1.1 billion in principal amount of 30-year unsecured Senior Notes GG at 99.470% of their principal amount. Senior Notes FF have a fixed interest rate of 1.25% and mature on August, 13, 2015, and Senior Notes GG have a fixed interest rate of 4.45% and mature on February 15, 2043. Net proceeds from the issuance of Senior Notes FF and GG were used to temporarily reduce borrowings under EPO's $3.5 Billion Multi-Year Revolving Credit Facility and for general company purposes.

Enterprise Products Partners L.P. has unconditionally guaranteed Senior Notes EE, FF and GG 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.

EPO utilized the 2010 Shelf to issue its Senior Notes EE in February 2012 and Senior Notes FF and GG in August 2012. We expect to repay our consolidated debt obligations maturing in 2013 by refinancing such obligations with long-term debt. For additional information regarding our consolidated debt obligations, see Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Issuance of Common Units during 2012

The following table summarizes the issuance of our common units during the three and nine months ended September 30, 2012 in connection with our underwritten equity offerings, "at-the-market" program, and quarterly distribution reinvestment plan ("DRIP") and employee unit purchase plan ("EUPP") (dollars in millions, number of units issued as shown):

	For the Three Months Ended September 30, 2012		For the Nine Months Ended September 30, 2012	
	Number of Common Units Issued	Net Proceeds Received	Number of Common Units Issued	Net Proceeds Received
Common units issued in connection with underwritten offering in September 2012	9,200,000	$ 473.3	9,200,000	$ 473.3
Common units issued during the third quarter of 2012 in connection with the at-the-market program	1,648,291	86.3	1,648,291	86.3
Common units issued in connection with the quarterly DRIP and EUPP during 2012	737,657	37.5	2,008,266	99.2
Totals	11,585,948	$ 597.1	12,856,557	$ 658.8

In September 2012, we utilized the 2010 Shelf to issue 9,200,000 common units (including an over-allotment of 1,200,000 common units) to the public at an offering price of $53.07 per unit, which generated total net cash proceeds of $473.3 million.

In May 2012, we entered into an equity distribution agreement with certain broker-dealers pursuant to which we may offer and sell up to $1.0 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 the agreement 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. A registration statement covering the issuance and sale of common units pursuant to this agreement was filed with the SEC in March 2012. During the third quarter of 2012, we issued 1,648,291 common units under this program for an aggregate price of $87.0 million, resulting in total net cash proceeds of $86.3 million. Proceeds from these sales were used for general company purposes, including funding capital expenditures.

For additional information regarding our 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 November 9, 2012, the investment-grade credit ratings of EPO's long-term senior unsecured debt securities were: BBB from Standard and Poor's; Baa2 from Moody's; and BBB from Fitch Ratings, and 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. 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.

Liquidation of Investment in Energy Transfer Equity

At December 31, 2011, we owned 29,303,514 common units of Energy Transfer Equity. On January 18, 2012, we sold 22,762,636 of these common units in a private transaction, which generated cash proceeds of $825.1 million. As a result of the January 18 transaction, our ownership interest in Energy Transfer Equity was reduced below 3%, and we discontinued using the equity method to account for this investment and began accounting for it as an investment in available-for-sale equity securities. The remaining 6,540,878 units were sold systematically through April 27, 2012 and generated additional total cash proceeds of $270.2 million. In the aggregate, the liquidation of this investment during 2012 resulted in $68.8 million of gains that are presented as a component of other income.

Commercial Paper Program

In August 2012, EPO established a commercial paper program under which it may issue (and have outstanding at any time) up to $2.0 billion in the aggregate of short-term commercial paper notes.   As of September 30, 2012, no notes had been issued under this program. We intend to maintain a minimum available borrowing capacity under EPO's existing $3.5 Billion Multi-Year Revolving Credit Facility equal to any amount outstanding under commercial paper notes as a back-stop to the program. To the extent such commercial paper notes are issued in the future, they will be senior unsecured obligations of EPO that are unconditionally guaranteed by Enterprise Products Partners L.P.   Proceeds generated from the issuance of these notes are expected to be used for general company purposes.

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, see the Unaudited Condensed Statements of Consolidated Cash Flows included under Part I, Item 1 of this quarterly report.

	For the Nine Months Ended September 30, 2012	2011
Net cash flows provided by operating activities	$ 1,615.8	$ 2,228.2
Cash used in investing activities	1,895.0	2,338.6
Cash provided by financing activities	273.9	74.0

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; 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 2011 Form 10-K.

The following information highlights significant period-to-period variances in our cash flow amounts and the primary drivers of these variances:

Comparison of Nine Months Ended September 30, 2012 with Nine Months Ended September 30, 2011

Operating Activities. The $612.4 million period-to-period decrease in net cash flows provided by operating activities was primarily due to the timing of cash receipts and disbursements partially offset by increased earnings (e.g., our gross operating margin increased $454.6 million period-to-period).

Investing Activities. The $443.6 million decrease in cash used for investing activities was primarily due to proceeds from asset sales, which increased $696.9 million period-to-period due to the liquidation of our remaining investment in Energy Transfer Equity common units for $1.1 billion during the January through April timeframe in 2012. Furthermore, capital spending for property, plant and equipment net of contributions in aid of construction costs decreased slightly by $82.0 million period-to-period. These cash inflows were partially offset by a $339.9 million increase in investments in unconsolidated affiliates primarily related to newly formed joint venture projects.

Financing Activities. Cash provided by financing activities increased $199.9 million period-to-period primarily due to the following:

§ Net borrowings under our consolidated debt agreements decreased $150.4 million period-to-period. EPO issued $2.5 billion and repaid $1.0 billion in principal amount of senior notes during the nine months ended September 30, 2012, compared to the issuance of $2.75 billion and repayment of $450.0 million in principal amount of senior notes during the nine months ended September 30, 2011. In addition, net repayments under our consolidated revolving bank credit facilities and term loans decreased $651.2 million period-to-period.

§ Monetization of interest rate derivative instruments during the nine months ended September 30, 2012 resulted in a net cash outflow of $147.8 million compared to a $23.2 million outflow for similar activities during the nine months ended September 30, 2011. For information regarding our interest rate hedging activities, see Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

§ Cash distributions paid to limited partners increased $153.7 million period-to-period primarily due to a higher number of distribution-bearing common units outstanding and the associated quarterly distribution rates.

§ Net cash proceeds from the issuance of common units increased $587.7 million period-to-period primarily due to our underwritten equity offering in September 2012 for 9,200,000 common units and the 1,648,291 common units we issued under the at-the-market program. Together, these offerings accounted for $559.6 million of net cash proceeds during the third quarter of 2012.

Capital Spending

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

Although our current focus is on expansion through growth capital projects, management continues to analyze potential business combinations, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In past years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We believe this trend will continue and we expect independent oil and natural gas companies to consider similar divestitures.

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

	For the Nine Months Ended September 30, 2012	For the Nine Months Ended September 30, 2011
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	$ 2,697.9	$ 2,779.9
Capital spending for investments in unconsolidated affiliates	351.8	11.9
Other investing activities	32.4	7.4
Total capital spending	$ 3,082.1	$ 2,799.2

For the nine months ended September 30, 2012, we spent $2.8 billion on growth capital projects, of which $1.2 billion was for Eagle Ford Shale projects.

Based on information currently available, we estimate our consolidated capital spending for 2012 will approximate $4.3 billion, which includes estimated expenditures of $4.0 billion for growth capital projects and $0.3 billion for sustaining capital expenditures. Our forecast of consolidated capital expenditures for 2012 is based on our announced strategic operating and growth plans, which are dependent upon our ability to generate the required funds from either operating cash flows or other means, including borrowings under debt agreements, issuance of additional debt and equity securities, and potential divestitures. We may revise our forecast of capital spending due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast of capital spending may change as a result of decisions made by management at a later date, which may include the addition of costs associated with unforeseen acquisition opportunities.

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

At September 30, 2012, we had $1.4 billion in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction projects in Texas, including those in the Eagle Ford Shale and at our Mont Belvieu facility.

Pipeline Integrity Costs

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Expensed	$ 15.1	$ 22.1	$ 52.0	$ 43.9
Capitalized	20.1	13.1	60.0	39.8
Total	$ 35.2	$ 35.2	$ 112.0	$ 83.7

We expect the cost of our pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $31.0 million for the remainder of 2012. The cost of our pipeline integrity program was $117.3 million for the year ended December 31, 2011.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our 2011 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;

- § revenue recognition policies and the use of estimates when recording revenue and expense accruals; and
- § reserves for environmental matters and litigation contingencies.

When used in the preparation of our Unaudited Condensed Consolidated Financial Statements, such estimates are based on our current knowledge and understanding of the underlying facts and circumstances and may be revised as a result of actions we take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our consolidated financial position, results of operations and cash flows.

Recent Accounting Developments

Accounting standard setting organizations have been very active in recent years. Recently, they issued new and revised accounting guidance on a number of topics, including disclosures related to offsetting assets and liabilities. We do not believe that adoption of this new guidance will have a material impact on our consolidated financial statements.

Other Items

Use of Non-GAAP Financial Measures

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered an alternative to GAAP operating income.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
NGL Pipelines & Services	$ 615.8	$ 547.6	$ 1,836.5	$ 1,549.7
Onshore Natural Gas Pipelines & Services	183.5	156.0	565.5	476.3
Onshore Crude Oil Pipelines & Services	117.6	67.4	252.7	167.0
Offshore Pipelines & Services	40.6	53.9	131.0	168.6
Petrochemical & Refined Products Services	182.1	145.6	437.2	397.8
Other Investments (1)	--	2.3	2.4	11.3
Total segment gross operating margin	$ 1,139.6	$ 972.8	$ 3,225.3	$ 2,770.7

(1) Represents the equity earnings we recorded from our previously held investment in Energy Transfer Equity. Our reporting for this segment ceased on January 18, 2012 when we stopped using the equity method to account for this investment. See Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report for additional information regarding the liquidation of our investment in Energy Transfer Equity.

The following table presents a reconciliation of 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 September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
Total segment gross operating margin	$ 1,139.6	$ 972.8	$ 3,225.3	$ 2,770.7
Adjustments to reconcile total segment gross operating margin to operating income:				
Amounts included in operating costs and expenses:				
Depreciation, amortization and accretion	(269.2)	(238.3)	(785.1)	(702.4)
Non-cash asset impairment charges	(43.1)	(5.2)	(57.6)	(5.2)
Operating lease expenses paid by EPCO	--	--	--	(0.3)
Gains (losses) related to asset sales	0.3	(17.6)	4.1	0.6
Gains from sale of ownership interests in equity-method unconsolidated affiliate – Energy Transfer Equity (1)	--	19.4	--	24.8
Gains related to property damage insurance recoveries (2)	2.3	--	30.0	--
General and administrative costs	(41.4)	(50.0)	(130.2)	(138.3)
Operating income	788.5	681.1	2,286.5	1,949.9
Other expense, net	(198.2)	(190.0)	(499.4)	(561.3)
Income before income taxes	$ 590.3	$ 491.1	$ 1,787.1	$ 1,388.6

(1) See "Liquidity and Capital Resources – Liquidation of Investment in Energy Transfer Equity" within this Item 2 for information related to these gains.
(2) See "Other Items – Insurance Matters" within this Item 2 for information regarding insurance recoveries.

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 balance of our revolving credit facility, the issuance of senior notes in February 2012 and August 2012, and the scheduled repayment of maturing debt obligations, there have been no significant changes in our consolidated debt obligations since those reported in our 2011 Form 10-K. See Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements under 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 2011 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, revenues, expenses, results of operations, liquidity, capital expenditures or capital resources.

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

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other insurance coverage, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance may not fully cover every type of damage, interruption or other loss that might occur. If we were to incur a significant loss for which we were not fully insured, it could have a material impact on our financial position, results of operations and cash flows. In addition, there may be timing differences between amounts we accrue related property damage expense, amounts we are required to pay in connection with a loss and amounts we subsequently receive from insurance carriers as reimbursements. Any event that materially interrupts the revenues generated by our consolidated operations, or other losses that require us to make material expenditures not reimbursed by insurance, could reduce our ability to pay distributions to our unitholders and, accordingly, adversely affect the market price of our common units.

Involuntary conversions result from the loss of an asset because of some unforeseen event (e.g., destruction due to fire). Some of these events are insurable, thus resulting in a property damage insurance recovery. Amounts we receive from insurance carriers are net of any deductibles related to the covered event. EPCO renewed its annual insurance programs during the second quarter of 2012. Under terms of the renewed policies, EPCO's deductibles now range from $5.0 million to $60.0 million depending on the nature of the loss (windstorm or non-windstorm) and the assets involved (onshore or offshore).

After performing a cost-benefit analysis, management elected to forego windstorm coverage for our Gulf of Mexico offshore assets. The combination of increasingly high deductibles and premiums resulted in such coverage being uneconomic to us; therefore, we chose to self-insure such operations for the current annual policy period. Although the new EPCO policies do not provide any windstorm coverage for offshore assets, producers affiliated with our Independence Hub and Marco Polo platforms provide physical damage windstorm coverage of $350.0 million for each of these key offshore assets.

During the three and nine months ended September 30, 2012, we collected $2.3 million and $30.0 million, respectively, of nonrefundable cash proceeds from insurance carriers that we recognized as a gain within operating costs and expenses. These proceeds relate to property damage claims we made in connection with the February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. To the extent that additional non-refundable insurance proceeds related to this incident are received, we expect to record gains equal to such proceeds.

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. Substantially all of our derivatives are used for non-trading activities.

Our exposures to market risk have not changed materially since those reported under Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," included in our 2011 Form 10-K.

We assess the risk of each of our derivative instrument portfolios using a sensitivity analysis model. The sensitivity analysis applied to each portfolio measures the potential income or loss (i.e., the change in fair value of the derivative instrument portfolio) based upon a hypothetical 10% movement in the underlying interest rates or quoted market prices (as applicable) at the dates indicated. In addition to these variables, the fair value of each portfolio is influenced by fluctuations in the notional amounts of the instruments and the discount rates used to determine the present values. The calculated results of the sensitivity analysis model do not reflect the impact that the same hypothetical price movement would have on the hedged exposures to which they relate.

We routinely review the effectiveness of our derivative instrument portfolios in light of current market conditions. If changes in market conditions or exposures warrant, the nature and volume of derivative instruments may change depending on the specific exposures being managed.

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. As presented in 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.

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value ("FV") of our interest rate swap portfolio at the dates indicated (dollars in millions):

		Interest Rate Swap Portfolio Aggregate Fair Value at		
Scenario	Resulting Classification	December 31, 2011	September 30, 2012	October 16, 2012
FV assuming no change in underlying interest rates	*Asset*	$ 67.2	$ 25.6	$ 27.5
FV assuming 10% increase in underlying interest rates	*Asset*	64.4	24.8	26.6
FV assuming 10% decrease in underlying interest rates	*Asset*	70.0	26.4	28.4

The decrease in fair value of the interest rate swap portfolio since December 31, 2011 is primarily due to the settlement of 11 fixed-to-floating swaps in February 2012, which resulted in receipts totaling $37.7 million.

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value ("FV") of our forward starting swap portfolio at the dates indicated (dollars in millions):

		Forward Starting Swap Portfolio Aggregate Fair Value at		
Scenario	Resulting Classification	December 31, 2011	September 30, 2012	October 16, 2012
FV assuming no change in underlying interest rates	*Liability*	$ (290.7)	$ (180.5)	$ (174.7)
FV assuming 10% increase in underlying interest rates	*Liability*	(251.8)	(163.0)	(156.7)
FV assuming 10% decrease in underlying interest rates	*Liability*	(330.6)	(198.4)	(193.0)

Due to a decrease in forward London Interbank Offered Rates in 2011, the fair value of our forward starting swap portfolio was a liability of $290.7 million at December 31, 2011. In connection with the issuance of Senior Notes EE in February 2012, we settled ten forward starting swaps having an aggregate notional value of $500.0 million, resulting in cash losses totaling $115.3 million. In connection with the issuance of Senior Notes FF and Senior Notes GG in August 2012, we settled seven additional forward starting swaps having an aggregate notional amount of $350.0 million, resulting in cash losses totaling $70.2 million. Although we incurred cash losses upon settlement of our forward starting swaps in February 2012 and August 2012, we benefited from the exceptionally low interest rate environment during these periods relative to the interest rates in effect at the time we entered into the swaps. The fair value of the remaining forward starting swaps was a liability of $180.5 million at September 30, 2012 and $174.7 million at October 16, 2012.

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 options contracts.

Our predominant commodity hedging strategies are: (i) hedging natural gas processing margins; (ii) hedging anticipated future contracted sales of NGLs, refined products and crude oil associated with volumes held in inventory; and (iii) hedging the fair value of natural gas in inventory. The following information summarizes these hedging strategies:

§ The objective of our natural gas processing strategy is to hedge an amount of gross margin associated with our natural gas processing activities. We achieve this objective by using physical and financial instruments to lock in the purchase prices of natural gas consumed as plant thermal reduction ("PTR") and the sales prices of the related NGL products. This program consists of (i) the forward sale of a portion of our expected equity NGL production at fixed prices through December 2012, which is achieved through the use of forward physical sales contracts and commodity derivative instruments and (ii) the purchase of commodity derivative instruments having a notional amount based on the volume of natural gas expected to be consumed as PTR in the production of such equity NGL production.

At September 30, 2012 and October 16, 2012, the program had hedged future remaining estimated gross margins (before plant operating expenses) of $141.1 million on 2.2 MMBbls of forecasted NGL sales transactions and equivalent PTR volumes extending through December 2012. Our estimates of future gross margins are subject to various business risks, including unforeseen outages or production declines, counterparty risk, or similar events or developments that are outside of our control.

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

§ 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.

Certain basis swaps, basis spread options and other derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of natural gas necessary to optimize our owned and contractually committed transportation and storage capacity. There is some uncertainty involved in the timing of these transactions often due to the development of more favorable profit opportunities or when spreads are insufficient to cover variable costs thus reducing the likelihood that the transactions will occur as originally forecasted. As a result of this timing uncertainty, these derivative instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of these assets. The earnings volatility caused by fluctuations in non-cash, mark-to-market earnings cannot be predicted and the impact to earnings could be material.

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

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2011**	**September 30, 2012**	**October 16, 2012**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ 22.2	$ (1.7)	$ (3.1)
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	14.9	(7.6)	(9.6)
FV assuming 10% decrease in underlying commodity prices	*Asset*	29.5	4.2	3.5

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

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2011	Portfolio Fair Value at September 30, 2012	Portfolio Fair Value at October 16, 2012
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (12.3)	$ 12.2	$ 7.7
FV assuming 10% increase in underlying commodity prices	*Liability*	(32.2)	(33.4)	(43.2)
FV assuming 10% decrease in underlying commodity prices	*Asset*	7.6	57.8	58.6

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, 2011	Portfolio Fair Value at September 30, 2012	Portfolio Fair Value at October 16, 2012
FV assuming no change in underlying commodity prices	*Liability*	$ (7.6)	$ (8.5)	$ (2.7)
FV assuming 10% increase in underlying commodity prices	*Liability*	(10.0)	(14.8)	(7.0)
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(5.0)	(2.2)	1.5

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, who is our principal executive officer) and chief financial officer (W. Randall Fowler, our principal financial officer), of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based on this evaluation, as of the end of the period covered by this quarterly report, Mr. Creel and Mr. Fowler concluded:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our principal executive and financial officers, as appropriate to allow for timely decisions regarding required disclosures; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the third quarter of 2012, 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*****.**

For information regarding litigation matters, see Note 14, "Commitments and Contingencies," of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report, which is incorporated herein by reference.

Item 1A. ***Risk Factors*****.**

Security holders and potential investors in our securities should carefully consider the risk factors set forth in our 2011 Form 10-K, in addition to other information in such annual report. The risk factors set forth in our 2011 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 nine months ended September 30, 2012:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
February 2012 (1)	187,343	$ 51.54	--	--
May 2012 (2)	186,048	$ 49.82	--	--
August 2012 (3)	7,942	$ 53.12	--	--
September 2012 (4)	1,087	$ 54.24	--	--

(1) Of the 632,298 restricted common units that vested in February 2012 and converted to common units, 187,343 units were sold back to us by employees to cover related withholding tax requirements.
(2) Of the 604,054 restricted common units that vested in May 2012 and converted to common units, 186,048 units were sold back to us by employees to cover related withholding tax requirements.
(3) Of the 28,131 restricted common units that vested in August 2012 and converted to common units, 7,942 units were sold back to us by employees to cover related withholding tax requirements.
(4) Of the 4,100 equity-based awards that vested in September 2012 and converted to common units, 1,087 units were sold back to us by employees to cover related withholding tax requirements.

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	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products GP, LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed September 7, 2010).
2.10	Contribution Agreement, dated as of September 30, 2010, by and between Enterprise Products Company and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2010).
2.11	Agreement and Plan of Merger, dated as of April 28, 2011, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPD MergerCo LLC, Duncan Energy Partners L.P. and DEP Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 29, 2011).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 9, 2007).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Enterprise Products Partners L.P., filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.6 to Form 8-K filed November 23, 2010).
3.3	Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated November 22, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K filed November 23, 2010).

3.4	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 11, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 16, 2011).
3.5	Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC) (incorporated by reference to Exhibit 3.3 to Form S-1/A Registration Statement, Reg. No. 333-124320, filed by Enterprise GP Holdings L.P. on July 22, 2005).
3.6	Certificate of Amendment to Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC), filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.5 to Form 8-K filed November 23, 2010).
3.7	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC dated effective as of September 7, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 8, 2011).
3.8	Company Agreement of Enterprise Products Operating LLC dated June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 8, 2007).
3.9	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.10	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
4.1	Form of Common Unit certificate (incorporated by reference to Exhibit A to Exhibit 3.1 to Form 8-K filed August 16, 2011).
4.2	Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.3	First Supplemental Indenture, dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	Second Supplemental Indenture, dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.5	Third Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed August 8, 2007).
4.6	Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 6, 2004).
4.7	Third Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 6, 2004).
4.8	Fourth Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 6, 2004).
4.9	Fifth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 3, 2005).
4.10	Sixth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 3, 2005).

4.11	Eighth Supplemental Indenture, dated as of July 18, 2006, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.12	Ninth Supplemental Indenture, dated as of May 24, 2007, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed May 24, 2007).
4.13	Tenth Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.14	Eleventh Supplemental Indenture, dated as of September 4, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed September 5, 2007).
4.15	Twelfth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.16	Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.17	Fourteenth Supplemental Indenture, dated as of December 8, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
4.18	Fifteenth Supplemental Indenture, dated as of June 10, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009).
4.19	Sixteenth Supplemental Indenture, dated as of October 5, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.20	Seventeenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.21	Eighteenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.22	Nineteenth Supplemental Indenture, dated as of May 20, 2010, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.23	Twentieth Supplemental Indenture, dated as of January 13, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.24	Twenty-First Supplemental Indenture, dated as of August 24, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 24, 2011).

4.25	Twenty-Second Supplemental Indenture, dated as of February 15, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.25 to Form 10-Q filed on May 10, 2012).
4.26	Twenty-Third Supplemental Indenture, dated as of August 13, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 13, 2012).
4.27	Global Note representing $350.0 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.28	Global Note representing $499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 10-K filed March 31, 2003).
4.29	Global Notes representing $450.0 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.30	Global Note representing $500.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.31	Global Note representing $150.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.32	Global Note representing $350.0 million principal amount of 6.65% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.33	Global Note representing $250.0 million principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed November 4, 2005).
4.34	Global Note representing $250.0 million principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed November 4, 2005).
4.35	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.36	Global Note representing $800.0 million principal amount of 6.30% Senior Notes due 2017 with attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 9, 2007).
4.37	Form of Global Note representing $400.0 million principal amount of 5.65% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.38	Form of Global Note representing $700.0 million principal amount of 6.50% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.39	Form of Global Note representing $500.0 million principal amount of 9.75% Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
4.40	Form of Global Note representing $500.0 million principal amount of 4.60% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009).
4.41	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).
4.42	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).

4.43	Form of Global Note representing $490.5 million principal amount of 7.625% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 28, 2009).
4.44	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).
4.45	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).
4.46	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).
4.47	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).
4.48	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).
4.49	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).
4.50	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).
4.51	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).
4.52	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).
4.53	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).
4.54	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).
4.55	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).
4.56	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).
4.57	Form of Global Note representing $650.0 million principal amount of 1.25% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 13, 2012).
4.58	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).
4.59	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).
4.60	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).
4.61	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).

4.62	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).
4.63	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).
4.64	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).
4.65	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).
4.66	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).
4.67	Fourth Supplemental Indenture, dated June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Val Verde Gas Gathering Company, L.P., TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.68	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).
4.69	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).
4.70	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).
4.71	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).
4.72	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).

4.73	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).
4.74	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).
4.75	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).
4.76	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).
4.77	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).
4.78	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 nine months ended September 30, 2012 and for each of the five years ended December 31, 2011, 2010, 2009, 2008 and 2007.
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P.'s for the September 30, 2012 quarterly report on Form 10-Q.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s for the September 30, 2012 quarterly report on Form 10-Q.
32.1#	Sarbanes-Oxley Section 906 certification of Michael A. Creel for Enterprise Products Partners L.P.'s for the September 30, 2012 quarterly report on Form 10-Q.
32.2#	Sarbanes-Oxley Section 906 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s for the September 30, 2012 quarterly report on Form 10-Q.
101.CAL#	XBRL Calculation Linkbase Document
101.DEF#	XBRL Definition Linkbase Document
101.INS#	XBRL Instance Document
101.LAB#	XBRL Labels Linkbase Document
101.PRE#	XBRL Presentation Linkbase Document
101.SCH#	XBRL Schema Document

*	With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file numbers for Enterprise Products Partners L.P., Enterprise GP Holdings L.P., TEPPCO Partners, L.P. and TE Products Pipeline Company, LLC are 1-14323, 1-32610, 1-10403 and 1-13603, respectively.
***	Identifies management contract and compensatory plan arrangements.
#	Filed with this report.

SIGNATURES

Pursuant to the requirements of 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 November 9, 2012.

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

EXHIBIT 12.1

ENTERPRISE PRODUCTS PARTNERS L.P.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in millions)

	For the Nine Months Ended September 30, 2012	For the Year Ended December 31, 2011	2010	2009	2008	2007
Consolidated income	$ 1,810.6	$ 2,088.3	$ 1,383.7	$ 1,140.3	$ 1,145.1	$ 762.0
Add: Provision for (benefit from) taxes	(23.5)	27.2	26.1	25.3	31.0	15.8
Less: Equity in earnings from unconsolidated affiliates	(42.2)	(46.4)	(62.0)	(92.3)	(66.2)	(13.6)
Consolidated pre-tax income before equity in earnings from unconsolidated affiliates	1,744.9	2,069.1	1,347.8	1,073.3	1,109.9	764.2
Add: Fixed charges	682.9	879.5	813.4	760.6	717.9	594.4
Amortization of capitalized interest	14.9	17.5	16.8	15.3	13.4	11.6
Distributed income of equity investees	67.5	156.4	191.9	169.3	157.2	116.9
Subtotal	2,510.2	3,122.5	2,369.9	2,018.5	1,998.4	1,487.1
Less: Capitalized interest	(86.4)	(106.7)	(47.2)	(53.1)	(90.7)	(86.5)
Net income attributable to noncontrolling interests	(6.2)	(20.5)	(25.5)	(26.4)	(23.0)	(14.8)
Total earnings	$ 2,417.6	$ 2,995.3	$ 2,297.2	$ 1,939.0	$ 1,884.7	$ 1,385.8
Fixed charges:						
Interest expense	$ 572.8	$ 744.1	$ 741.9	$ 687.3	$ 608.3	$ 487.4
Capitalized interest	86.4	106.7	47.2	53.1	90.7	86.5
Interest portion of rental expense	23.7	28.7	24.3	20.2	18.9	20.5
Total	$ 682.9	$ 879.5	$ 813.4	$ 760.6	$ 717.9	$ 594.4
Ratio of earnings to fixed charges	3.5x	3.4x	2.8x	2.6x	2.6x	2.3x

These computations take into account our consolidated operations and the distributed income from our equity method investees. For purposes of these calculations, "earnings" is the amount resulting from adding and subtracting the following items:

Add the following, as applicable:

- consolidated pre-tax income from continuing operations before adjustment for income or loss from equity investees;
- fixed charges;
- amortization of capitalized interest;
- distributed income of equity investees; and
- our share of pre-tax losses of equity investees for which charges arising from guarantees are included in fixed charges.

From the subtotal of the added items, subtract the following, as applicable:

- interest capitalized;
- preference security dividend requirements of consolidated subsidiaries; and
- the noncontrolling interests in pre-tax income of subsidiaries that have not incurred fixed charges.

The term "fixed charges" means the sum of the following: interest expensed and capitalized; amortized premiums, discounts and capitalized expenses related to indebtedness; an estimate of the interest within rental expense; and preference security dividend requirements of consolidated subsidiaries.

EXHIBIT 31.1

SARBANES-OXLEY SECTION 302 CERTIFICATION

I, Michael A. Creel, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enterprise Products Partners L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2012

/s/ Michael A. Creel

Name:	Michael A. Creel
Title:	Chief Executive Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.

EXHIBIT 31.2

SARBANES-OXLEY SECTION 302 CERTIFICATION

I, W. Randall Fowler, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enterprise Products Partners L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2012

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Financial Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

**CERTIFICATION OF MICHAEL A. CREEL, CHIEF EXECUTIVE OFFICER
OF ENTERPRISE PRODUCTS HOLDINGS LLC, THE GENERAL PARTNER OF
ENTERPRISE PRODUCTS PARTNERS L.P.**

In connection with this quarterly report of Enterprise Products Partners L.P. (the "Registrant") on Form 10-Q for the quarterly period ended September 30, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael A. Creel, Chief Executive Officer of Enterprise Products Holdings LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ Michael A. Creel

Name: Michael A. Creel
Title: Chief Executive Officer of Enterprise Products Holdings LLC,
the General Partner of Enterprise Products Partners L.P.

Date: November 9, 2012

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF W. RANDALL FOWLER, CHIEF FINANCIAL OFFICER OF ENTERPRISE PRODUCTS HOLDINGS LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this quarterly report of Enterprise Products Partners L.P. (the "Registrant") on Form 10-Q for the quarterly period ended September 30, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Randall Fowler, Chief Financial Officer of Enterprise Products Holdings LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Financial Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.

Date: November 9, 2012