UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 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, 2011

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 ☐

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 870,641,175 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, 2011. Our common units trade on the New York Stock Exchange under the ticker symbol “EPD.”

ENTERPRISE PRODUCTS PARTNERS L.P.
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PART I. FINANCIAL INFORMATION.

Item 1. *Financial Statements*.

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

ASSETS	September 30, 2011	December 31, 2010
Current assets:		
Cash and cash equivalents	$ 29.1	$ 65.5
Restricted cash	78.6	98.7
Accounts receivable – trade, net of allowance for doubtful accounts of $13.4 at September 30, 2011 and $18.4 at December 31, 2010	4,008.4	3,800.1
Accounts receivable – related parties	37.5	36.8
Inventories	1,389.3	1,134.0
Assets held for sale (see Note 6)	455.1	--
Prepaid and other current assets	350.4	372.0
Total current assets	6,348.4	5,507.1
Property, plant and equipment, net	21,388.1	19,332.9
Investments in unconsolidated affiliates	1,908.5	2,293.1
Intangible assets, net of accumulated amortization of $955.6 at September 30, 2011 and $932.3 at December 31, 2010	1,686.6	1,841.7
Goodwill	2,092.3	2,107.7
Other assets	300.5	278.3
Total assets	$ 33,724.4	$ 31,360.8

LIABILITIES AND EQUITY	September 30, 2011	December 31, 2010
Current liabilities:		
Current maturities of debt	$ 1,000.0	$ 282.3
Accounts payable – trade	820.8	542.0
Accounts payable – related parties	212.2	133.1
Accrued product payables	4,715.5	4,164.8
Accrued interest	183.9	252.9
Liabilities related to assets held for sale (see Note 6)	72.2	--
Other current liabilities	639.3	505.1
Total current liabilities	7,643.9	5,880.2
Long-term debt (see Note 10)	14,108.7	13,281.2
Deferred tax liabilities	83.8	78.0
Other long-term liabilities	336.5	220.6
Commitments and contingencies		
Equity: (see Note 11)		
Partners' equity:		
Limited partners:		
Common units (870,649,071 units outstanding at September 30, 2011 and 843,681,572 units outstanding at December 31, 2010)	11,657.0	11,288.2
Class B units (4,520,431 units outstanding at September 30, 2011 and December 31, 2010)	118.5	118.5
Accumulated other comprehensive loss	(336.8)	(32.5)
Total partners' equity	11,438.7	11,374.2
Noncontrolling interests	112.8	526.6
Total equity	11,551.5	11,900.8
Total liabilities and equity	$ 33,724.4	$ 31,360.8

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,	
	2011	2010	2011	2010
Revenues:				
Third parties	$ 11,163.2	$ 7,934.1	$ 32,169.1	$ 23,673.6
Related parties	163.9	133.7	558.2	482.1
Total revenues (see Note 12)	11,327.1	8,067.8	32,727.3	24,155.7
Costs and expenses:				
Operating costs and expenses:				
Third parties	10,146.2	7,117.1	29,398.3	21,441.1
Related parties	458.4	343.0	1,276.7	965.1
Total operating costs and expenses	10,604.6	7,460.1	30,675.0	22,406.2
General and administrative costs:				
Third parties	20.0	28.8	49.2	61.5
Related parties	30.0	41.3	89.1	89.4
Total general and administrative costs	50.0	70.1	138.3	150.9
Total costs and expenses (see Note 12)	10,654.6	7,530.2	30,813.3	22,557.1
Equity in income of unconsolidated affiliates	8.6	5.6	35.9	43.2
Operating income	681.1	543.2	1,949.9	1,641.8
Other income (expense):				
Interest expense	(189.0)	(192.0)	(561.1)	(529.1)
Interest income	0.3	0.9	0.9	1.6
Other, net	(1.3)	0.4	(1.1)	0.2
Total other expense, net	(190.0)	(190.7)	(561.3)	(527.3)
Income before provision for income taxes	491.1	352.5	1,388.6	1,114.5
Provision for income taxes	(11.6)	(4.9)	(26.1)	(20.1)
Net income	479.5	347.6	1,362.5	1,094.4
Net income attributable to noncontrolling interests (see Note 11)	(8.1)	(310.6)	(36.7)	(933.4)
Net income attributable to partners	$ 471.4	$ 37.0	$ 1,325.8	$ 161.0
Allocation of net income attributable to partners:				
Limited partners	$ 471.4	$ 37.0	$ 1,325.8	$ 161.0
General partner	$ --	$ *	$ --	$ *
Earnings per unit: (see Note 14)				
Basic earnings per unit	$ 0.57	$ 0.18	$ 1.62	$ 0.77
Diluted earnings per unit	$ 0.55	$ 0.18	$ 1.55	$ 0.77

See Notes to Unaudited Condensed Consolidated Financial Statements.
* Amount is negligible.

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,	
	2011	**2010**	**2011**	**2010**
Net income	$ 479.5	$ 347.6	$ 1,362.5	$ 1,094.4
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instruments:				
Changes in fair value of cash flow hedges	(6.1)	(64.1)	(179.2)	(31.0)
Reclassification of gains and losses to net income	35.1	(25.6)	178.8	(10.6)
Interest rate derivative instruments:				
Changes in fair value of cash flow hedges	(260.1)	(81.6)	(306.1)	(168.4)
Reclassification of losses to net income	1.6	8.1	4.6	21.4
Foreign currency derivative instruments:				
Changes in fair value of cash flow hedges	--	0.1	--	(0.1)
Reclassification of gains to net income	--	--	--	(0.3)
Total cash flow hedges	(229.5)	(163.1)	(301.9)	(189.0)
Foreign currency translation adjustment	--	0.5	--	0.3
Change in funded status of pension and postretirement plans, net of tax	--	--	(0.6)	(0.9)
Proportionate share of other comprehensive income (loss) of unconsolidated affiliate	--	11.9	(0.7)	11.5
Total other comprehensive loss	(229.5)	(150.7)	(303.2)	(178.1)
Comprehensive income	250.0	196.9	1,059.3	916.3
Comprehensive income attributable to noncontrolling interests	(8.1)	(167.2)	(36.7)	(768.0)
Comprehensive income attributable to partners	$ 241.9	$ 29.7	$ 1,022.6	$ 148.3

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, 2011	For the Nine Months Ended September 30, 2010
Operating activities:		
Net income	$ 1,362.5	$ 1,094.4
Reconciliation of net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	739.2	709.1
Non-cash asset impairment charges	5.2	1.5
Equity in income of unconsolidated affiliates	(35.9)	(43.2)
Distributions received from unconsolidated affiliates	122.5	146.0
Operating lease expenses paid by EPCO	0.3	0.5
Gains from asset sales and related transactions	(25.4)	(45.4)
Deferred income tax expense	5.5	3.7
Changes in fair market value of derivative instruments	(6.8)	(10.8)
Effect of pension settlement recognition	(0.5)	(0.2)
Net effect of changes in operating accounts (see Note 17)	61.6	(411.8)
Net cash flows provided by operating activities	2,228.2	1,443.8
Investing activities:		
Capital expenditures	(2,792.2)	(1,405.1)
Contributions in aid of construction costs	12.3	13.9
Decrease in restricted cash	20.1	37.9
Cash used for business combinations	--	(1,233.0)
Investments in unconsolidated affiliates	(11.9)	(6.3)
Proceeds from asset sales and related transactions (see Note 17)	440.5	89.6
Other investing activities	(7.4)	1.5
Cash used in investing activities	(2,338.6)	(2,501.5)
Financing activities:		
Borrowings under debt agreements	6,565.1	4,170.3
Repayments of debt	(4,989.3)	(2,816.6)
Debt issuance costs	(33.9)	(14.7)
Cash distributions paid to partners (see Note 11)	(1,459.7)	(227.6)
Cash distributions paid to noncontrolling interests (see Note 11)	(52.0)	(1,099.0)
Cash contributions from noncontrolling interests (see Note 11)	4.7	1,034.4
Net cash proceeds from issuance of common units	67.1	--
Acquisition of treasury units in connection with equity-based awards	(10.1)	(3.1)
Other financing activities	(17.9)	1.3
Cash provided by financing activities	74.0	1,045.0
Effect of exchange rate changes on cash	--	0.3
Net change in cash and cash equivalents	(36.4)	(12.7)
Cash and cash equivalents, January 1	65.5	55.3
Cash and cash equivalents, September 30	$ 29.1	$ 42.9

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
(See Note 11 for Unit History, Accumulated Other Comprehensive Loss and Noncontrolling Interests)
(Dollars in millions)

	Partners' Equity			
	Limited Partners	Accumulated Other Comprehensive 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
Operating lease expenses paid by EPCO	0.3	--	--	0.3
Cash distributions paid to 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
Acquisition of treasury units in connection with equity-based awards	(10.1)	--	--	(10.1)
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)
Proportionate share of other comprehensive loss of unconsolidated affiliate	--	(0.7)	--	(0.7)
Other	4.7	(0.6)	(1.6)	2.5
Balance, September 30, 2011	$ 11,775.5	$ (336.8)	$ 112.8	$ 11,551.5

	Partners' Equity				
	Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total
Balance, December 31, 2009	$ 1,972.4	$ *	$ (33.3)	$ 8,534.0	$ 10,473.1
Net income	161.0	*	--	933.4	1,094.4
Operating lease expenses paid by EPCO	--	--	--	0.5	0.5
Cash distributions paid to partners	(227.6)	*	--	--	(227.6)
Cash distributions paid to noncontrolling interests	--	--	--	(1,099.0)	(1,099.0)
Cash contributions from noncontrolling interests	--	--	--	1,034.4	1,034.4
Acquisition of treasury units in connection with equity-based awards	--	--	--	(3.1)	(3.1)
Amortization of fair value of equity-based awards	3.8	--	--	45.9	49.7
Common units issued in exchange for ownership interests in truck transport business	--	--	--	30.6	30.6
Cash flow hedges	--	--	(24.2)	(164.8)	(189.0)
Proportionate share of other comprehensive income of unconsolidated affiliate	--	--	11.5	--	11.5
Other	--	--	--	(0.6)	(0.6)
Balance, September 30, 2010	$ 1,909.6	$ *	$ (46.0)	$ 9,311.3	$ 11,174.9

See Notes to Unaudited Condensed Consolidated Financial Statements.
* Amount is negligible.

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.

SIGNIFICANT RELATIONSHIPS REFERENCED IN THE 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 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 Delaware limited liability company.

On September 3, 2010, Enterprise GP Holdings L.P. ("Holdings"), Enterprise, Enterprise GP, Enterprise Products GP, LLC ("EPGP," the former general partner of Enterprise) and Enterprise ETE LLC ("Holdings MergerCo," a Delaware limited liability company and a wholly owned subsidiary of Enterprise) entered into a merger agreement (the "Holdings Merger Agreement"). On November 22, 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with and into Holdings MergerCo and related transactions were completed, with Holdings MergerCo surviving such merger (collectively, we refer to these transactions as the "Holdings Merger"). Enterprise's membership interests in Holdings MergerCo were subsequently contributed to EPO. For additional information regarding the Holdings Merger, see Note 1.

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 and one of three managers of Dan Duncan LLC; (ii) Dr. Ralph S. Cunningham, who is also a director and the Chairman of Enterprise GP and one of three managers of Dan Duncan LLC; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP and one of three managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company 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 serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President and Chief Executive Officer ("CEO") of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also directors of EPCO.

On April 28, 2011, we, our general partner, EPD MergerCo LLC ("Duncan MergerCo," a Delaware limited liability company and 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"). On September 7, 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"). For additional information regarding the Duncan Merger, see Note 1.

References to "TEPPCO" and "TEPPCO GP" mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their mergers with our subsidiaries on October 26, 2009. We refer to such related mergers both individually and in the aggregate as the "TEPPCO Merger."

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP") and

Regency Energy Partners LP. We own noncontrolling limited partner interests in Energy Transfer Equity, which we account for using the equity method of accounting. Energy Transfer Equity electronically files reports with the U.S. Securities and Exchange Commission ("SEC"), including annual reports on Form 10-K and quarterly reports on Form 10-Q. The SEC maintains an Internet website at www.sec.gov that contains the periodic reports and other information regarding this registrant.

References to "Employee Partnerships" mean EPE Unit L.P., EPE Unit II, L.P., EPE Unit III, L.P., Enterprise Unit L.P. and EPCO Unit L.P., collectively, all of which were privately held affiliates of EPCO. The Employee Partnerships were liquidated in August 2010. See Note 3 for additional information.

Note 1. Partnership Operations, Organization and Basis of Presentation

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 ("NGL") businesses of EPCO. We are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. Our assets include approximately 50,000 miles of onshore and offshore pipelines; 192 million barrels ("MMBbls") of storage capacity for NGLs, refined products and crude oil; and 27 billion cubic feet ("Bcf") of total working natural gas storage capacity.

Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminaling; crude oil and refined products transportation, storage, and terminaling; offshore production platforms; petrochemical transportation and services; and a marine transportation business that operates primarily on the United States inland and Intracoastal Waterway systems and in the Gulf of Mexico. We have six reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; (v) Petrochemical & Refined Products Services; and (vi) Other Investments. Our business segments reflect the manner in which these businesses are managed and reviewed by the CEO of our general partner. See Note 12 for additional information regarding our business segments.

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 and under the collective common control of the DD LLC and 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 13 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 rate of 1.01 Enterprise common units for each Duncan Energy Partners common unit. Enterprise issued 24,277,310 of its common units (net of 9 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.

Impact of the Holdings Merger on the Basis of Presentation of our Consolidated Financial Statements

On November 22, 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with Holdings MergerCo and related transactions were completed, with Holdings MergerCo surviving such merger. At the effective time of the Holdings Merger, Enterprise GP succeeded as Enterprise's general partner, and each issued and outstanding unit representing limited partner interests in Holdings was cancelled and converted into the right to receive Enterprise common units based on an exchange ratio of 1.5 Enterprise common units for each Holdings unit. Enterprise issued an aggregate of 208,813,454 of its common units (net of 23 fractional common units cashed out) as consideration in the Holdings Merger and, immediately after the merger, cancelled 21,563,177 of its common units previously owned by Holdings.

In connection with the Holdings Merger, Enterprise's partnership agreement was amended and restated to provide for the cancellation of its general partner's 2% economic interest and incentive distribution rights in Enterprise. In addition, a privately held affiliate of EPCO agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from Enterprise with respect to a certain number of Enterprise's common units (the "Designated Units") over a five-year period after the merger closing date. The number of Designated Units to which the temporary distribution waiver applies is as follows for distributions to be paid, if any, during the following periods: 30,610,000 during 2011; 26,130,000 during 2012; 23,700,000 during 2013; 22,560,000 during 2014; and 17,690,000 during 2015.

Prior to the Holdings Merger, Enterprise was a consolidated subsidiary of Holdings, which was Enterprise's parent. Upon completion of the Holdings Merger, Holdings merged with and into a wholly owned subsidiary of Enterprise. The Holdings Merger resulted in Holdings being considered the surviving consolidated entity for accounting purposes, while Enterprise is the surviving consolidated entity for legal and reporting purposes. For accounting purposes, Holdings is deemed the acquirer of the noncontrolling interests in Enterprise that were previously recognized in Holdings' consolidated financial statements (i.e., the acquisition of Enterprise's limited partner interests that were owned by parties other than Holdings). While it was a publicly traded partnership, Holdings (NYSE, ticker symbol "EPE") electronically filed its annual and quarterly consolidated financial statements with the SEC. You can access this information at www.sec.gov.

As a result of the Holdings Merger, Enterprise's consolidated financial and operating results prior to November 22, 2010 have been presented as if it were Holdings from an accounting perspective (i.e., the financial statements of Holdings become the historical financial statements of Enterprise). The primary differences between Holdings' and Enterprise's consolidated results of operations were: (i) general and administrative costs incurred by Holdings and EPGP (Enterprise's former general partner); (ii) equity in income of Holdings' noncontrolling ownership interests in Energy Transfer Equity; and (iii) interest expense associated with Holdings' debt. In addition, for periods prior to November 22, 2010, the net assets, income, cash distributions and contributions and other amounts attributable to Enterprise's limited partner interests that were owned by third parties and related parties other than Holdings are presented as a component of noncontrolling interests. See Note 11 for additional information regarding noncontrolling interests.

Limited partner units outstanding and earnings per unit amounts presented in these consolidated financial statements for periods prior to the Holdings Merger have been retroactively adjusted to reflect the 1.5 to one unit-for-unit exchange that occurred in connection with the Holdings Merger. See Note 14 for additional information regarding our earnings per unit amounts.

Note 2. General Accounting Matters

Our results of operations for the three and nine months ended September 30, 2011 are not necessarily indicative of results expected for the full year of 2011. 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 SEC.

These Unaudited Condensed Consolidated Financial Statements and the Notes thereto should be read in conjunction with the Audited Consolidated Financial Statements and Notes thereto included in our annual report on Form 10-K for the year ended December 31, 2010 (the "2010 Form 10-K") filed on March 1, 2011.

Allowance for Doubtful Accounts

Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts, including those related to natural gas imbalances. Our procedure for estimating the allowance for doubtful accounts is based on: (i) historical experience with customers, (ii) the perceived financial stability of customers based on our research and (iii) the levels of credit we grant to customers. In addition, we may increase the allowance for doubtful accounts in response to the specific identification of customers involved in bankruptcy proceedings and similar financial difficulties. On a routine basis, we review estimates associated with the allowance for doubtful accounts to ensure that we have recorded sufficient reserves to cover potential losses.

The following table presents our allowance for doubtful accounts activity for the periods presented:

	For the Nine Months Ended September 30,	
	2011	**2010**
Balance at beginning of period	$ 18.4	$ 16.8
Charged to costs and expenses	0.8	1.3
Deductions (1)	(5.8)	--
Balance at end of period	$ 13.4	$ 18.1

(1) The 2011 deduction amount is primarily due to our reassessment of the allowance for doubtful accounts as a result of improved credit ratings of a significant customer, which reduced our exposure to potential uncollectibility.

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 15 for additional information regarding our contingencies.

Derivative Instruments

We use derivative instruments such as swaps, forward contracts and other arrangements to manage price risks associated with inventories, firm commitments, interest rates and certain anticipated transactions. To qualify for hedge accounting, the item to be hedged must expose us to risk and the related derivative instrument must reduce that exposure and meet specific hedge documentation requirements. We formally designate a derivative instrument as a hedge and document and assess the effectiveness of the hedge at inception and thereafter on a quarterly basis.

For certain of our derivative instruments, we apply the normal purchase/normal sale exception, which precludes the recognition of changes in mark-to-market values for these derivatives in our consolidated financial statements. The revenues and expenses associated with these transactions are recognized when volumes are physically delivered or received.

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

Earnings Per Unit

Earnings per unit is based on the amount of net income attributable to limited partners and the weighted-average number of limited partner units outstanding during a period. See Note 14 for additional information regarding our earnings per unit amounts.

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 of fixed and identifiable intangible assets, (ii) impairment testing of fixed and intangible assets (including goodwill), (iii) reserves for environmental matters, (iv) natural gas imbalances, (v) contingencies and (vi) 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.

Fair Value Information

The carrying amounts of cash and cash equivalents (including restricted cash), accounts receivable and accounts payable approximate their fair values based on their short-term nature. See Note 4 for fair value information associated with our derivative instruments.

The estimated total fair value of our fixed-rate long-term debt obligations was approximately $15.43 billion and $12.91 billion at September 30, 2011 and December 31, 2010, respectively. These values are based on quoted market prices for such debt or debt of similar terms and maturities. 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. See Note 8 for summarized financial information of our investments accounted for using the equity method.

Liquids Exchange Contracts

In total, our liquids exchange balances were payables of $407.8 million and $144.1 million at September 30, 2011 and December 31, 2010, respectively. The most significant liquids exchange transactions recorded on our consolidated balance sheet relate to those involving petrochemical volumes. Petrochemical transactions accounted for approximately 84% and 85% of our liquids exchange transactions recorded at September 30, 2011 and December 31, 2010, respectively. Under these agreements, we physically receive volumes of propane/propylene mix (an unprocessed stream), including the risk of loss and legal title to such volumes, from the exchange counterparty. In turn, we deliver segregated polymer grade propylene and propane (processed streams) back to the customer and charge them a processing or similar fee. The intent of these exchange transactions is the earning of fee revenue for processing and transporting the propane/propylene mix using our assets. This arrangement satisfies the commercial, logistical and timing needs of the customer and allows us to operate our plants more effectively.

To the extent that the aggregate volumes we receive under such exchange agreements exceed those we deliver under the agreements during a period (measured as of the end of each reporting period), we recognize a net exchange payable position with the counterparties. With respect to the petrochemical transactions discussed above, we are typically in a net exchange payable position with our counterparties. In those limited situations where the aggregate volumes we deliver exceed those we receive during a period (measured as of the end of each reporting period), we recognize a net exchange receivable position with the counterparties. From an income statement perspective, the only revenue recognized from such exchange agreements is fee revenue. From a balance sheet perspective, net exchange payables arising from these transactions are valued at market-based prices. To the extent that we recognize net exchange receivables arising from liquids exchange transactions, such balances are valued at average cost.

Volumetric receivables and payables arising from liquids exchange contracts are typically balanced with movements of products rather than with cash. When payment or receipt of monetary consideration is required for product differentials and service costs with a counterparty, such items are recognized in our consolidated financial statements on a net basis as either operating revenues or expense, as appropriate.

Recent Accounting Developments

The following recent accounting developments will impact our future consolidated financial statements:

Fair Value Measurements. In May 2011, the Financial Accounting Standards Board (or "FASB") issued an accounting standard update that amended previous fair value measurement and disclosure guidance. These amendments generally involve clarifications on how to measure and disclose fair value amounts recognized in the financial statements. They also expand the disclosure requirements, particularly for Level 3 fair value measurements, to include a description of the valuation processes used and an analysis of the sensitivity of the fair value measurements to changes in unobservable inputs and the interrelationships between those unobservable inputs, if any. We will adopt this guidance on January 1, 2012 and apply its requirements prospectively at that time. We do not believe the adoption of this guidance will have a material impact on our consolidated financial statements.

Presentation of Other Comprehensive Income. In June 2011, the FASB issued an accounting standard update that revised the financial statement presentation of other comprehensive income. The amended guidance requires entities to present components of comprehensive income in either (i) a single continuous statement of comprehensive income or (ii) two separate but consecutive statements (i.e., a statement of income and a statement of comprehensive income, which is our current format). Although the amended guidance does not change the items that must be reported in other comprehensive income, reclassification adjustments for each component of other comprehensive income would be displayed separately on the statement of income and in other comprehensive income. In October 2011, the FASB announced its intention to defer the requirement related to the separate presentation of reclassification adjustments. Based on the current guidance, we do not believe the adoption of this guidance will have a material impact on our consolidated financial statements.

Testing for Goodwill Impairment. In September 2011, the FASB issued an accounting standard update that provides entities with an option to perform a qualitative assessment to determine whether further impairment testing is necessary. We will adopt this guidance on January 1, 2012 and apply its requirements prospectively at that time. We do not believe the adoption of this guidance will have a material impact on our consolidated financial statements.

Restricted Cash

Restricted cash represents amounts held in connection with our commodity derivative instruments portfolio and related physical natural gas, crude oil and NGL purchases. Additional cash may be restricted to maintain this portfolio as commodity prices fluctuate or deposit requirements change. At September 30, 2011 and December 31, 2010, our restricted cash amounts were $78.6 million and $98.7 million, respectively. See Note 4 for information regarding derivative instruments and hedging activities.

Note 3. Equity-based Awards

An allocated portion of the fair value of EPCO's equity-based awards is charged to us under the ASA. The following table summarizes the 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,	
	2011	**2010**	**2011**	**2010**
Restricted common unit awards	$ 11.9	$ 9.6	$ 35.4	$ 23.3
Unit option awards	0.7	1.0	2.4	2.4
Other (1)	0.2	27.9	--	32.6
Total compensation expense	$ 12.8	$ 38.5	$ 37.8	$ 58.3

(1) Primarily consists of unit appreciation rights ("UARs"), phantom units and similar awards. Also, the amounts presented for 2010 include awards related to limited partnership interests in the Employee Partnerships, which were liquidated in August 2010.

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, 2011, 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").

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

Plan. After giving effect to awards granted under the plan through September 30, 2011, a total of 1,488,906 additional common units could be issued.

The 2008 Plan provides for awards of our common units and other rights to our non-employee directors and to consultants and employees of EPCO and its affiliates providing services to us. Awards under the 2008 Plan may be granted in the form of unit options, restricted common units, phantom units, UARs and DERs. Up to 10,000,000 of our common units may be issued as awards under the 2008 Plan. After giving effect to awards granted under the plan through September 30, 2011, a total of 4,737,750 additional common units could be issued.

In connection with the Duncan Merger, the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan ("2010 Plan") was terminated. The 2010 Plan provided for awards to employees, directors or consultants providing services to Duncan Energy Partners. Awards under the 2010 Plan were granted in the form of restricted common units. There were no awards outstanding under the 2010 Plan at September 6, 2011 (i.e., immediately prior to the Duncan Merger). See Note 1 for information regarding the Duncan Merger.

Restricted Common Unit Awards

Restricted common unit awards allow recipients to acquire (at no cost to the recipient apart from service or other conditions) limited partner units once a defined vesting period expires, subject to customary forfeiture provisions. Restricted common unit awards are denominated in our common units and, prior to the Duncan Merger, those of Duncan Energy Partners depending on the issuer of the award. Restricted common unit awards issued prior to 2010 generally cliff vest four years from the date of grant. Beginning with awards issued in 2010, restricted common unit awards are typically subject to graded vesting provisions in which one-fourth of each award vests on the first, second, third and fourth anniversaries of the date of grant. 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 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 periods presented:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Enterprise restricted common unit awards:		
Restricted common units at December 31, 2010	3,561,614	$ 29.78
Granted (2)	1,381,530	$ 43.63
Vested	(886,508)	$ 31.46
Forfeited	(129,899)	$ 33.51
Restricted common units at September 30, 2011	3,926,737	$ 34.15
Duncan Energy Partners restricted common unit awards:		
Restricted common units at December 31, 2010	--	$ --
Granted (3)	3,666	$ 32.56
Vested (3)	(3,666)	$ 32.56
Restricted common units at September 6, 2011	--	$ --

(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 2011 was $60.3 million based on a grant date market price of our common units ranging from $40.54 to $43.70 per unit. An estimated annual forfeiture rate of 4.6% was applied to these awards.
(3) The aggregate grant date fair value of restricted common unit awards issued in 2011 was $0.1 million based on a grant date market price of Duncan Energy Partners' common units of $32.56 per unit. These awards 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 by the respective issuer. Since these restricted common units are participating securities, such distributions are included in cash distributions paid to partners (post-Holdings Merger) and cash distributions paid to noncontrolling interests (pre-Holdings Merger) as presented on our Unaudited Condensed Statements of Consolidated Cash Flows.

The following table presents cash distributions paid with respect to our restricted common units and the total intrinsic value of restricted common units that vested during the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
Cash distributions paid to restricted common unit holders	$ 2.4	$ 2.0	$ 7.2	$ 5.8
Total intrinsic value of restricted common unit awards vesting during period	$ 2.3	$ 0.6	$ 37.5	$ 12.0

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate $61.3 million at September 30, 2011, of which our allocated share of the cost is currently estimated to be $57.9 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, these unit option awards have a vesting period of four years from the date of grant and expire five years after the date of grant.

The fair value of each unit option is estimated on the date of grant using a Black-Scholes option pricing model, which incorporates various assumptions including expected life of the option, risk-free interest rates, expected distribution yield of our common units, and expected unit price volatility. In general, our assumptions regarding the expected life of the options represent the period of time that the options are expected to be outstanding based on an analysis of our historical option activity. Our selection of risk-free interest rates is based on published yields for U.S. government securities with comparable terms. The unit price volatility and expected distribution yield assumptions are based on several factors, including an analysis of our common units historical market price and its distribution yield over a period of time equal to the expected life of the option, respectively. Compensation expense recorded in connection with unit options is based on the grant date fair value of such awards, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

The following table presents unit option 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 options at December 31, 2010	3,753,420	$ 28.08	3.6	$ --
Unit options at September 30, 2011	3,753,420	$ 28.08	2.9	$ 6.7
Options exercisable at September 30, 2011 (2)	--		--	$ --

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated. There were no vested unit options outstanding at December 31, 2010.

(2) We were committed to issue 3,753,420 of our common units at September 30, 2011 if all outstanding options awarded were exercised. Option awards outstanding at September 30, 2011 include 712,280 awards that vested during the first nine months of 2011. Of the remaining outstanding option awards at September 30, 2011, 736,000, 1,520,140 and 785,000 will vest in 2012, 2013, and 2014, respectively. These unit option awards become exercisable in the calendar year following the year in which they vest.

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 options during the periods presented:

	For the Three Months Ended September 30, 2010	For the Nine Months Ended September 30, 2010
Total intrinsic value of unit option awards exercised during period	$ 7.5	$ 9.7
Cash received from EPCO in connection with the exercise of unit option awards	5.0	6.6
Unit option-related reimbursements to EPCO	7.5	9.7

For the EPCO group of companies, the unrecognized compensation cost associated with unit option awards was an aggregate $4.4 million at September 30, 2011, of which our allocated share of the cost is currently estimated to be $3.9 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 1.7 years.

Other

Unit appreciation rights. UARs entitle the recipient to receive a cash payment on the vesting date of the award equal to the excess, if any, of the then current fair market value of our common units over the grant date fair value of the award. UARs are accounted for as liability awards.

The following tables present information regarding UARs for the period presented:

UARs at December 31, 2010	170,104
Vested	(17,776)
Settled or forfeited	(45,000)
UARs at September 30, 2011	107,328

	September 30, 2011	December 31, 2010
Accrued liability for UARs	$ 0.4	$ 1.0

At September 30, 2011, 107,328 UARs that had been granted under the 2006 Plan to certain employees of EPCO who work on our behalf were outstanding. These awards are subject to five-year cliff vesting requirements and are expected to settle in 2012. The grant date fair value with respect to these UARs is based on a unit price of $37.00 for our common units. If the employee resigns prior to vesting, the UARs are forfeited. Equity-based compensation expense associated with UARs was minimal for the three months ended September 30, 2011 and $0.2 million for the three months ended September 30, 2010. For the nine months ended September 30, 2011 and 2010, equity-based compensation associated with UARs was a credit of $0.6 million and an expense of $0.5 million, respectively.

Limited partnership interests. EPCO granted its key employees who perform services on behalf of us, EPCO and other affiliated companies, limited partnership interests in the Employee Partnerships, which were privately held affiliates of EPCO. These partnerships were liquidated in August 2010. Prior to liquidation, the limited partnership interests entitled each holder to participate in the expected long-term appreciation in value of the equity securities owned by each Employee Partnership. Each Employee Partnership owned either Enterprise common units or Holdings' units or a combination of both. Equity-based compensation expense for the three and nine months ended September 30, 2010 includes $27.5 million and $31.3 million, respectively, of expense associated with these limited partnership interests.

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. Derivatives are financial instruments whose fair value is determined by changes in a specified benchmark such as interest rates or commodity prices. Fair value is generally defined as the amount at which a derivative instrument could be exchanged in a current transaction between willing parties, not in a forced sale. Derivative instruments typically include futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

We are required to recognize derivative instruments at fair value as either assets or liabilities on our balance sheet. While all derivatives are required to be reported at fair value on the balance sheet, changes in fair value of the derivative instruments are reported in different ways, depending on the nature and effectiveness of the hedging activities to which they relate. After meeting specified conditions, a qualified derivative may be designated as a total or partial hedge of:

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

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

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

A contract designated as a cash flow hedge of an anticipated transaction that is probable of not 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 Derivative Instruments

We utilize interest rate swaps, treasury locks 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 following table summarizes our interest rate swap derivative instruments outstanding at September 30, 2011:

Hedged Transaction	Number and Type of Derivative(s) Employed	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes C	1 fixed-to-floating swap	$100.0	1/04 to 2/13	6.4% to 2.3%	Fair value hedge
Senior Notes G	3 fixed-to-floating swaps	$300.0	10/04 to 10/14	5.6% to 1.4%	Fair value hedge
Senior Notes P	7 fixed-to-floating swaps	$400.0	6/09 to 8/12	4.6% to 2.6%	Fair value hedge
Senior Notes AA	10 fixed-to-floating swaps	$750.0	1/11 to 2/16	3.2% to 1.2%	Fair value hedge
Undesignated swaps	6 floating-to-fixed swaps	$600.0	5/10 to 7/14	0.2% to 2.0%	Mark-to-market

As of September 30, 2011, we had six interest rate swap contracts with a notional value of $600.0 million that have not been designated as hedges. These derivative instruments are accounted for using mark-to-market accounting. Mark-to-market net losses (a component of consolidated interest expense) attributable to these undesignated swaps were $8.8 million and $19.3 million for the three and nine months ended September 30, 2011, respectively. In August 2011, two of these undesignated interest rate swaps (with a notional amount of $250 million) expired.

Interest rate swaps exchange the stated interest rate paid on a notional amount of debt for the fixed or floating interest rate stipulated in the derivative instrument. Interest expense for the three months ended September 30, 2011 and 2010 reflects a decrease of $1.8 million and an increase of $1.3 million, respectively, attributable to interest rate swaps. For the nine months ended September 30, 2011 and 2010, such swaps resulted in a decrease in interest expense of $9.3 million and $0.9 million, respectively.

The following table summarizes our forward starting interest rate swaps, which hedge the expected underlying benchmark interest rates related to forecasted issuances of debt, outstanding at September 30, 2011:

Hedged Transaction	Number and Type of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Future debt offering	10 forward starting swaps	$500.0	2/12	4.5%	Cash flow hedge
Future debt offering	7 forward starting swaps	$350.0	8/12	3.7%	Cash flow hedge
Future debt offering	16 forward starting swaps	$1,000.0	3/13	3.7%	Cash flow hedge

In connection with the issuance of Senior Notes during the nine months ended September 30, 2011 (see Note 10), we settled three forward starting swaps and two treasury locks having an aggregate notional amount of $1.47 billion, resulting in losses totaling $23.2 million. These losses will be amortized to earnings (as an increase in interest expense) using the effective interest method over the forecasted hedged period.

Commodity Derivative Instruments

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward agreements, futures contracts, fixed-for-float swaps, basis swaps and options contracts. The following table summarizes our commodity derivative instruments outstanding at September 30, 2011:

	Volume (1)		**Accounting**
Derivative Purpose	**Current** (2)	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (“PTR”) (3)	24.8 Bcf	n/a	Cash flow hedge
Forecasted sales of NGLs (4)	6.4 MMBbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted sales of octane enhancement products	1.0 MMBbls	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	10.4 Bcf	0.5 Bcf	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	1.1 MMBbls	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	1.5 MMBbls	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products	1.5 MMBbls	n/a	Cash flow hedge
Forecasted sales of refined products	1.7 MMBbls	n/a	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil	1.0 MMBbls	n/a	Cash flow hedge
Forecasted sales of crude oil	1.3 MMBbls	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (5,6)	351.3 Bcf	65.1 Bcf	Mark-to-market
Refined products risk management activities (6)	1.6 MMBbls	n/a	Mark-to-market
Crude oil risk management activities (6)	5.4 MMBbls	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 2012, January 2013 and December 2013, respectively.
(3) PTR represents the British thermal unit 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 1.1 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.
(5) Current and long-term volumes include approximately 61.6 Bcf and 1.4 Bcf, respectively, 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 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 March 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 inventory hedging program is to hedge the fair value of natural gas 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.

Credit-Risk Related Contingent Features in Derivative Instruments

A limited number of our commodity derivative instruments include provisions related to credit ratings and/or adequate assurance clauses. A credit rating provision provides for a counterparty to demand immediate full or partial payment to cover a net liability position upon the loss of a stipulated credit rating. An adequate assurance clause provides for a counterparty to demand immediate full or partial payment to cover a net liability position should reasonable grounds for insecurity arise with respect to contractual performance by either party. At September 30, 2011, the aggregate fair value of our over-the-counter derivative instruments in a net liability position was $0.4 million. The maximum potential cash payment under the contracts containing a credit rating contingent feature is $1.4 million. The potential for derivatives with contingent features to enter a net liability position may change in the future as commodity positions and prices fluctuate.

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, 2011		December 31, 2010		September 30, 2011		December 31, 2010	
	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	$ 44.3	Other current assets	$ 30.3	Other current liabilities	$ 152.0	Other current liabilities	$ 5.5
Interest rate derivatives	Other assets	48.0	Other assets	77.8	Other liabilities	111.7	Other liabilities	26.2
Total interest rate derivatives		92.3		108.1		263.7		31.7
Commodity derivatives	Other current assets	49.8	Other current assets	46.3	Other current liabilities	69.4	Other current liabilities	93.0
Commodity derivatives	Other assets	0.2	Other assets	1.0	Other liabilities	--	Other liabilities	1.7
Total commodity derivatives (1)		50.0		47.3		69.4		94.7
Total derivatives designated as hedging instruments		$ 142.3		$ 155.4		$ 333.1		$ 126.4
Derivatives not designated as hedging instruments								
Interest rate derivatives	Other current assets	$ --	Other current assets	$ --	Other current liabilities	$ 11.2	Other current liabilities	$ 21.0
Interest rate derivatives	Other assets	--	Other assets	--	Other liabilities	12.9	Other liabilities	0.9
Total interest rate derivatives		--		--		24.1		21.9
Commodity derivatives	Other current assets	29.3	Other current assets	38.6	Other current liabilities	33.2	Other current liabilities	41.2
Commodity derivatives	Other assets	6.8	Other assets	4.5	Other liabilities	2.9	Other liabilities	5.4
Total commodity derivatives		36.1		43.1		36.1		46.6
Foreign currency derivatives	Other current assets	0.2	Other current assets	0.3	Other current liabilities	--	Other current liabilities	0.1
Total derivatives not designated as hedging instruments		$ 36.3		$ 43.4		$ 60.2		$ 68.6

(1) Represents commodity derivative instrument transactions that have either not settled or have settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

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 Recognized in Income on Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2011	2010	2011	2010
Interest rate derivatives	Interest expense	$ 23.6	$ 8.1	$ 32.4	$ 27.1
Commodity derivatives	Revenue	8.6	6.1	7.3	9.0
Total		$ 32.2	$ 14.2	$ 39.7	$ 36.1

Derivatives in Fair Value Hedging Relationships	Location	Loss Recognized in Income on Hedged Item			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2011	2010	2011	2010
Interest rate derivatives	Interest expense	$ (22.5)	$ (8.6)	$ (32.2)	$ (26.8)
Commodity derivatives	Revenue	(7.7)	(7.0)	(8.8)	(9.4)
Total		$ (30.2)	$ (15.6)	$ (41.0)	$ (36.2)

The following tables present the effect of our derivative instruments designated as cash flow hedges on our Unaudited Condensed Statements of Consolidated Comprehensive Income and Consolidated Operations 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,	
	2011	2010	2011	2010
Interest rate derivatives (1)	$ (260.1)	$ (81.6)	$ (306.1)	$ (168.4)
Commodity derivatives – Revenue (2)	8.8	(44.2)	(166.0)	42.2
Commodity derivatives – Operating costs and expenses	(14.9)	(19.9)	(13.2)	(73.2)
Foreign currency derivatives	--	0.1	--	(0.1)
Total	$ (266.2)	$ (145.6)	$ (485.3)	$ (199.5)

(1) The other comprehensive loss recognized for interest rate derivatives for the third quarter of 2011 and year-to-date 2011 is primarily due to the impact of decreases in forward London Interbank Offered Rates ("LIBOR") on our forward starting interest rate swap portfolio. The change in fair value of this portfolio between June 30, 2011 and September 30, 2011 accounted for $242.7 million of the quarterly other comprehensive loss. Any gain or loss ultimately recognized upon settlement of these cash flow hedges would be amortized into earnings as a reduction or increase, respectively, in interest expense over the forecasted hedge period of 10 years.

(2) The increase in other comprehensive income for the third quarter of 2011 and loss for the year-to-date 2011 is primarily due to the impact of falling and rising prices, respectively, on our crude oil, refined products and NGL derivative instruments designated as cash flow hedges of future physical sales transactions.

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,	
		2011	2010	2011	2010
Interest rate derivatives	Interest expense	$ (1.6)	$ (8.1)	$ (4.6)	$ (21.4)
Commodity derivatives	Revenue	(33.2)	39.2	(181.7)	41.7
Commodity derivatives	Operating costs and expenses	(1.9)	(13.6)	2.9	(31.1)
Foreign currency derivatives	Other income	--	--	--	0.3
Total		$ (36.7)	$ 17.5	$ (183.4)	$ (10.5)

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,	
		2011	2010	2011	2010
Commodity derivatives	Revenue	$ --	$ --	$ 0.2	$ --
Commodity derivatives	Operating costs and expenses	(0.9)	(0.4)	(0.9)	2.5
Total		$ (0.9)	$ (0.4)	$ (0.7)	$ 2.5

Over the next twelve months, we expect to reclassify $14.3 million of losses attributable to interest rate derivative instruments from accumulated other comprehensive loss to earnings as an increase in interest expense. Likewise, we expect to reclassify $32.2 million of losses attributable to commodity derivative instruments from accumulated other comprehensive loss to earnings, $10.8 million as an increase in operating costs and expenses and $21.4 million as a decrease in revenue.

The following table presents the effect of our derivative instruments not designated as hedging instruments on our Unaudited Condensed Statements of Consolidated Operations for the periods 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,	
		2011	2010	2011	2010
Interest rate derivatives	Interest expense	$ (8.8)	$ --	$ (19.3)	$ --
Commodity derivatives	Revenue	4.3	17.0	17.6	12.0
Commodity derivatives	Operating costs and expenses	--	--	--	(1.5)
Foreign currency derivatives	Other income	0.2	0.1	0.2	0.1
Total		$ (4.3)	$ 17.1	$ (1.5)	$ 10.6

Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. 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. Recognized valuation techniques employ inputs such as product prices, 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 or disclosed in the financial statements based on the observability of inputs used to estimate such fair values. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). At each balance sheet reporting date, we categorize our financial assets and liabilities using this hierarchy.

The following table sets forth, by level within the fair value hierarchy, the carrying values of our financial assets and liabilities at the date indicated. These assets and liabilities are measured on a recurring basis and are classified within the table 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.

	At September 30, 2011			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets:				
Interest rate derivatives	$ --	$ 92.3	$ --	$ 92.3
Commodity derivatives	43.9	36.9	5.3	86.1
Foreign currency derivatives	--	0.2	--	0.2
Total	$ 43.9	$ 129.4	$ 5.3	$ 178.6
Financial liabilities:				
Interest rate derivatives	$ --	$ 287.8	$ --	$ 287.8
Commodity derivatives	49.6	51.3	4.6	105.5
Total	$ 49.6	$ 339.1	$ 4.6	$ 393.3

The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

§ Level 1 fair values are based on quoted prices, which are available in active markets for identical assets or liabilities as of the measurement date. Active markets are defined as those in which transactions for identical assets or liabilities occur with sufficient frequency so as to provide pricing information on an ongoing basis (e.g., the New York Mercantile Exchange). Our Level 1 fair values consist of financial assets and liabilities such as exchange-traded commodity derivative instruments.

§ Level 2 fair values are based on pricing inputs other than quoted prices in active markets (as reflected in Level 1 fair values) and are either directly or indirectly observable as of the measurement date. Level 2 fair values include instruments that are valued using financial models or other appropriate valuation methodologies. Such financial models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, the time value of money, volatility factors, current market and contractual prices for the underlying instruments and other relevant economic measures. Substantially all of these assumptions (i) are observable in the marketplace throughout the full term of the instrument; (ii) can be derived from observable data; or (iii) are validated by inputs other than quoted prices (e.g., interest rate and yield curves at commonly quoted intervals). Our Level 2 fair values primarily consist of commodity derivative instruments such as forwards, swaps and other instruments transacted on an exchange or over-the-counter and interest rate derivative instruments. The fair values of these derivative instruments are based on observable price quotes for similar products and locations. The fair value of our interest rate derivatives are determined using financial models that incorporate the implied forward London Interbank Offered Rate yield curve for the same period as the future interest rate swap settlements.

§ Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect management's ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available to us in the circumstances, which might include our internally developed data. Level 3 inputs are typically used in connection with internally developed valuation methodologies where we make our best estimate of an instrument's fair value. Our Level 3 fair values primarily consist of ethane, normal butane and natural gasoline-based contracts with terms greater than one year and certain options used to hedge natural gas storage inventory and transportation capacities. In addition, we often rely on price quotes from reputable brokers who publish price quotes on certain products and compare these prices to other reputable brokers for the same products in the same markets whenever possible. These prices, when combined with data from our commodity derivative instruments, are used in our models to determine the fair value of such instruments.

Transfers within the fair value hierarchy routinely occur for certain term contracts as prices and other inputs used for the valuation of future delivery periods become more observable with the passage of time. Other transfers are made periodically in response to changing market conditions that affect liquidity, price observability and other inputs used in determining valuations. Based on an assessment completed during the first quarter of 2011, we transferred ethane, normal butane and natural gasoline-based contracts with terms ranging from two months to one year from Level 3 to Level 2. These transfers were made after a sustained increase in the observability of forward prices for these energy commodity products relative to the date range stated above as demonstrated by narrowing bid/offer spreads, higher transaction volumes and more activity and liquidity for these types of contracts. With the exception of the transfers noted above, no other transfers were made between fair value levels during the year-to-date period.

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

	For the Nine Months Ended September 30,	
	2011	2010
Balance, January 1	$ (25.9)	$ 5.7
Total gains (losses) included in:		
Net income (1)	(0.5)	(3.6)
Other comprehensive income (loss)	16.2	(8.3)
Settlements	0.8	3.6
Transfers out of Level 3 (2)	9.8	--
Balance, March 31	0.4	(2.6)
Total gains included in:		
Net income (1)	1.9	16.2
Other comprehensive income (loss)	--	22.2
Settlements	(0.2)	(16.2)
Transfers out of Level 3	--	0.2
Balance, June 30	2.1	19.8
Total gains (losses) included in:		
Net income (1)	0.8	18.2
Other comprehensive income (loss)	--	(31.4)
Settlements	(2.2)	(16.1)
Balance, September 30	$ 0.7	$ (9.5)

(1) 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. There were $6.4 million and $4.1 million of unrealized gains included in these amounts for the three and nine months ended September 30, 2010, respectively.

(2) Transfers out of Level 3 into Level 2 were primarily due to the change in observability of forward NGL prices as described above.

Nonfinancial Assets and Liabilities

Using appropriate valuation techniques, we reduced the carrying value of certain pipeline assets recorded as property, plant and equipment to fair value based on the present value of expected future cash flows (Level 3), resulting in a nonrecurring fair value adjustment (i.e., a non-cash asset impairment charge) totaling $5.2 million during the nine months ended September 30, 2011. This impairment charge resulted from the anticipated abandonment of certain pipeline laterals on our TPC Offshore gathering system.

During the nine months ended September 30, 2010, certain pipeline assets recorded as property, plant and equipment were adjusted to fair value based on the present value of expected future cash flows (Level 3), resulting in nonrecurring fair value adjustments totaling $1.5 million.

The non-cash asset impairment charges we recorded during the nine months ended September 30, 2011 and 2010 are a component of operating costs and expenses.

Note 5. Inventories

Inventories primarily consist of NGLs, petrochemicals and refined products, crude oil and natural gas volumes that are valued at the lower of average cost or market. We capitalize, as a cost of inventory, shipping and handling charges (e.g., pipeline transportation and storage fees) and other related costs associated with purchased volumes. As volumes are sold and delivered out of inventory, the cost of these volumes (including freight-in charges that have been capitalized as part of inventory cost) are charged to operating costs and expenses. Our inventory amounts by product type were as follows at the dates indicated:

	September 30, 2011	December 31, 2010
NGLs	$ 666.7	$ 548.3
Petrochemicals and refined products	566.3	399.7
Crude oil	103.7	121.1
Natural gas	52.6	64.7
Other	--	0.2
Total	$ 1,389.3	$ 1,134.0

In those instances where we take ownership of inventory volumes through percent-of-liquids contracts and similar arrangements (as opposed to actually purchasing volumes for cash from third parties), these volumes are valued at market-based prices during the month in which they are acquired. In general, our inventory levels have increased since December 31, 2010 due to an increase in the average cost of NGLs and seasonal supply and demand fluctuations.

Due to fluctuating commodity prices, we recognize lower of cost or market adjustments when the carrying value of our 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 summarizes our cost of sales and lower of cost or market adjustments for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
Cost of sales (1)	$ 9,787.6	$ 6,814.0	$ 28,397.2	$ 20,499.5
Lower of cost or market adjustments	5.1	0.2	6.8	7.1

(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. Assets Held for Sale

During September 2011, we committed to a formal plan to sell the equity interests of a wholly owned subsidiary, Crystal Holding L.L.C. ("Crystal"), which owns two underground salt dome natural gas storage facilities and associated pipelines located near Petal and Hattiesburg, Mississippi. The facilities have a combined 28.8 Bcf of total storage capacity (of which 18.6 Bcf is total working gas capacity) and are owned by Petal Gas Storage, L.L.C. ("Petal") and Hattiesburg Gas Storage Company ("Hattiesburg"). At September 30, 2011, the assets and liabilities of Crystal were classified as held for sale and we stopped depreciating and amortizing the Crystal assets. Crystal's operations are a component of our Onshore Natural Gas Pipelines & Services business segment.

On October 16, 2011, we announced the execution of definitive agreements to sell our ownership interests in Crystal to Boardwalk HP Storage Company, LLC for $550 million in cash. This transaction is subject to customary regulatory approvals and is expected to close during the fourth quarter of 2011.

The following table presents the major classes of assets and liabilities designated as held for sale on our consolidated balance sheet at September 30, 2011. With the exception of certain amounts recorded in property, plant and equipment and other assets, the amounts in the table all relate to Crystal.

Assets held for sale:		
Current assets	$	9.5
Property, plant and equipment, net (1)		374.8
Intangible assets, net		41.2
Goodwill		14.8
Other assets (2)		14.8
Total assets held for sale (presented as a component of our current assets)	$	455.1
Liabilities related to assets held for sale:		
Current liabilities	$	14.7
Long-term debt		57.2
Other long-term liabilities		0.3
Total liabilities related to assets held for sale (presented as a component of our current liabilities)	$	72.2

(1) Includes $31.7 million of surplus material unrelated to Crystal.
(2) Represents pipeline linefill held for sale unrelated to Crystal.

Our consolidated results of operations for the nine months ended September 30, 2011 and 2010 included $19.6 million and $23.1 million of depreciation and amortization expense related to the Crystal assets.

We have determined that Crystal's operations do not meet the criteria to be classified as discontinued operations. Following the proposed sale, we will continue to have significant commercial contracts and operational arrangements at the Petal and Hattiesburg facilities, which are adjacent to and currently share certain operating assets with our retained Petal NGL storage facility.

Note 7. 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, 2011	December 31, 2010
Plants, pipelines and facilities (1)	3-45 (6)	$ 19,747.3	$ 19,388.4
Underground and other storage facilities (2)	5-40 (7)	1,556.2	1,477.8
Platforms and facilities (3)	20-31	637.5	637.5
Transportation equipment (4)	3-10	136.1	119.1
Marine vessels (5)	15-30	603.7	560.0
Land		137.3	123.4
Construction in progress		3,590.0	1,607.2
Total		26,408.1	23,913.4
Less accumulated depreciation		5,020.0	4,580.5
Property, plant and equipment, net		$ 21,388.1	$ 19,332.9

(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 property, plant and equipment of Petal and Hattiesburg has been reclassified to assets held for sale as of September 30, 2011. See Note 6 for additional information regarding Petal and Hattiesburg's assets held for sale.

Full commercial operations on the Haynesville Extension of our Acadian Gas System commenced November 1, 2011. At September 30, 2011, the Haynesville Extension accounted for $1.37 billion of our construction in progress balance.

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,	
	2011	2010	2011	2010
Depreciation expense (1)	$ 195.0	$ 184.9	$ 571.3	$ 552.9
Capitalized interest (2)	33.1	12.5	75.1	33.5

(1) Depreciation expense is a component of "Costs and expenses" as presented on our Unaudited Condensed Statements of Consolidated Operations.
(2) Capitalized interest increases the carrying value of the associated asset and 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. In general, our contractual AROs primarily result from right-of-way agreements associated with our pipeline operations and leases of plant sites. In addition, we have recorded AROs based on government regulations triggered by the abandonment or retirement of (i) certain underground storage facilities and related above-ground brine storage pits, (ii) offshore Gulf of Mexico assets and (iii) certain marine vessels. Our AROs may also result from regulatory requirements associated with the renovation or demolition of certain assets containing hazardous substances such as asbestos.

The following table presents information regarding our AROs since December 31, 2010:

ARO liability balance, December 31, 2010	$	97.1
Revisions in estimated cash flows		4.7
Accretion expense		4.8
Liabilities settled during period		(3.2)
Liabilities incurred during period		0.5
ARO liability balance, September 30, 2011	$	103.9

Property, plant and equipment at September 30, 2011 and December 31, 2010 includes $38.0 million and $34.1 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. The following table presents our accretion expense forecasts for AROs for the periods presented:

Remainder of 2011	**2012**	**2013**	**2014**	**2015**
$ 1.7	$ 5.3	$ 5.7	$ 6.1	$ 5.8

Certain of our unconsolidated affiliates have AROs recorded at September 30, 2011 and December 31, 2010 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our consolidated financial statements.

Note 8. Investments in Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for using the equity method of accounting. We group our investments in unconsolidated affiliates according to the business segment to which they relate (see Note 12 for a general discussion of our business segments). The following table shows our investments in unconsolidated affiliates by business segment at the dates indicated:

	Ownership Interest at September 30, 2011	September 30, 2011	December 31, 2010
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 34.2	$ 31.9
K/D/S Promix, L.L.C. ("Promix")	50%	40.6	43.5
Baton Rouge Fractionators LLC	32.2%	21.1	21.9
Skelly-Belvieu Pipeline Company, L.L.C.	50%	34.5	34.2
Onshore Natural Gas Pipelines & Services:			
Evangeline (1)	49.5%	5.0	6.4
White River Hub, LLC ("White River Hub")	50%	26.0	26.2
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company ("Seaway")	50%	173.1	172.2
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36%	55.5	57.2
Cameron Highway Oil Pipeline Company	50%	225.6	233.7
Deepwater Gateway, L.L.C.	50%	95.4	98.4
Neptune Pipeline Company, L.L.C.	25.7%	52.4	53.9
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	9.5	10.1
Centennial Pipeline LLC ("Centennial")	50%	55.3	63.1
Other (2)	Various	3.5	3.6
Other Investments:			
Energy Transfer Equity	13.6%	1,076.8	1,436.8
Total		$ 1,908.5	$ 2,293.1

(1) Evangeline refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.
(2) 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.

In September 2011, Enterprise, Enbridge Energy Partners, L.P. and Anadarko Petroleum Corporation formed a joint venture, Texas Express Pipeline LLC ("TEP"), to design and construct a new NGL pipeline (the "Texas Express Pipeline") that will originate at Skellytown, Texas and extend approximately 580 miles to our NGL fractionation and storage facilities in Mont Belvieu, Texas. Subject to regulatory approvals, the Texas Express Pipeline is expected to begin service in the second quarter of 2013. As of September 30, 2011, we owned a 45% ownership interest and a nominal investment in TEP. Significant initial contributions from the joint venture members are expected to occur during the fourth quarter of 2011.

The Other Investments segment consists of noncontrolling ownership interests in Energy Transfer Equity, which is accounted for using the equity method. At September 30, 2011, we owned 30,411,954 common units of Energy Transfer Equity. Our equity investments are part of our long-term business strategy; however, we may from time-to-time elect to divest of a portion of our long-term equity investments in order to redeploy capital. In May and July 2011, we sold a total of 8,564,136 Energy Transfer Equity common units for net cash proceeds of $333.5 million and recorded aggregate gains of $24.8 million on the sales. Proceeds from these transactions were used for general partnership purposes, including funding capital expenditures.

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,	
	2011	2010	2011	2010
NGL Pipelines & Services	$ 4.3	$ 5.1	$ 16.4	$ 12.1
Onshore Natural Gas Pipelines & Services	1.4	1.2	4.1	3.4
Onshore Crude Oil Pipelines & Services	(1.0)	1.6	(3.1)	7.5
Offshore Pipelines & Services	5.4	10.1	20.3	33.0
Petrochemical & Refined Products Services	(3.8)	(0.5)	(13.1)	(5.8)
Other Investments	2.3	(11.9)	11.3	(7.0)
Total	$ 8.6	$ 5.6	$ 35.9	$ 43.2

On occasion, the price we pay to acquire an ownership interest in a company exceeds the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our investments in unconsolidated affiliates. The following table presents the unamortized excess cost amounts by business segment at the dates indicated:

	September 30, 2011	December 31, 2010
NGL Pipelines & Services	$ 24.9	$ 25.7
Onshore Crude Oil Pipelines & Services	19.4	19.7
Offshore Pipelines & Services	15.1	16.0
Petrochemical & Refined Products Services	2.9	3.0
Other Investments (1)	1,168.7	1,525.1
Total	$ 1,231.0	$ 1,589.5

(1) Holdings' investment in Energy Transfer Equity exceeded its share of the historical cost of the underlying net assets of such investee by $1.66 billion in May 2007. At September 30, 2011, this basis differential decreased to $1.17 billion (after taking into account related amortization amounts and the sale of 8.56 million Energy Transfer Equity common units during 2011) and consisted of the following: $366.5 million attributed to fixed assets; $397.7 million attributed to the incentive distribution rights (an indefinite-life intangible asset) held by Energy Transfer Equity in the cash flows of ETP; $144.4 million attributed to amortizable intangible assets and $260.1 million attributed to equity method goodwill. These unamortized excess cost amounts are being amortized over their estimated economic lives of 20-27 years, as applicable.

We amortize such excess cost amounts as a reduction in equity earnings in a manner similar to depreciation. The following table presents our amortization of such excess cost amounts by business segment for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
NGL Pipelines & Services	$ 0.3	$ 0.2	$ 0.8	$ 0.7
Onshore Crude Oil Pipelines & Services	0.1	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	1.0
Other Investments	7.1	9.2	24.6	27.5
Total	$ 7.9	$ 9.9	$ 26.9	$ 30.6

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Summarized Income Statement Information of Unconsolidated Affiliates

The following tables present unaudited income statement information (on a 100% basis) of our unconsolidated affiliates, aggregated by business segment, for the periods presented:

	Summarized Income Statement Information for the Three Months Ended					
	September 30, 2011			September 30, 2010		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income	Net Income (Loss)
NGL Pipelines & Services	$ 105.2	$ 20.7	$ 20.5	$ 78.3	$ 17.3	$ 17.3
Onshore Natural Gas Pipelines & Services	59.5	2.9	3.0	63.8	2.6	2.4
Onshore Crude Oil Pipelines & Services	11.9	(0.5)	(0.5)	16.6	5.8	5.8
Offshore Pipelines & Services	38.8	15.0	14.6	49.4	25.3	25.1
Petrochemical & Refined Products Services	5.9	(4.8)	(6.9)	15.1	2.5	0.2
Other Investments (1)	2,097.9	270.0	69.1	1,587.8	202.1	(15.3)

(1) Net income for Energy Transfer Equity represents net income attributable to the partners of Energy Transfer Equity.

	Summarized Income Statement Information for the Nine Months Ended					
	September 30, 2011			September 30, 2010		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income	Net Income (Loss)
NGL Pipelines & Services	$ 321.7	$ 74.6	$ 74.5	$ 227.8	$ 43.8	$ 43.7
Onshore Natural Gas Pipelines & Services	149.7	8.2	8.3	159.8	7.0	6.7
Onshore Crude Oil Pipelines & Services	32.7	(2.1)	(2.1)	57.1	23.9	23.9
Offshore Pipelines & Services	128.8	51.6	50.8	155.8	81.3	80.5
Petrochemical & Refined Products Services	25.2	(17.2)	(23.7)	39.3	0.5	(6.6)
Other Investments (1)	6,061.9	894.8	224.0	4,822.3	720.2	116.7

(1) Net income for Energy Transfer Equity represents net income attributable to the partners of Energy Transfer Equity.

With the exception of Energy Transfer Equity, all of these investments are in untraded privately held companies, the fair values of which are not practicable to estimate. At September 30, 2011, the fair value of our investment in Energy Transfer Equity was $1.06 billion based on the closing market price of Energy Transfer Equity's common units on that date. The market price of Energy Transfer Equity limited partner units increased subsequent to September 30, 2011.

Note 9. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	September 30, 2011			December 31, 2010		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 340.8	$ (122.9)	$ 217.9	$ 340.8	$ (106.7)	$ 234.1
Contract-based intangibles (1)	293.7	(164.4)	129.3	322.2	(176.6)	145.6
Segment total	634.5	(287.3)	347.2	663.0	(283.3)	379.7
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,163.6	(197.9)	965.7	1,163.6	(160.8)	1,002.8
Contract-based intangibles (2)	464.8	(285.2)	179.6	565.3	(322.0)	243.3
Segment total	1,628.4	(483.1)	1,145.3	1,728.9	(482.8)	1,246.1
Onshore Crude Oil Pipelines & Services:						
Customer relationship intangibles	9.7	(4.0)	5.7	9.7	(3.7)	6.0
Contract-based intangibles	0.4	(0.2)	0.2	0.4	(0.2)	0.2
Segment total	10.1	(4.2)	5.9	10.1	(3.9)	6.2
Offshore Pipelines & Services:						
Customer relationship intangibles	205.8	(126.6)	79.2	205.8	(118.1)	87.7
Contract-based intangibles	1.2	(0.3)	0.9	1.2	(0.2)	1.0
Segment total	207.0	(126.9)	80.1	207.0	(118.3)	88.7
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.4	(27.3)	77.1	104.7	(23.8)	80.9
Contract-based intangibles	57.8	(26.8)	31.0	60.3	(20.2)	40.1
Segment total	162.2	(54.1)	108.1	165.0	(44.0)	121.0
Total all segments	$ 2,642.2	$ (955.6)	$ 1,686.6	$ 2,774.0	$ (932.3)	$ 1,841.7

(1) In March 2011, we sold a non-strategic fractionation facility and its related contract-based intangible assets.
(2) The intangible assets of Petal and Hattiesburg have been reclassified to assets held for sale as of September 30, 2011. See Note 6 for additional information regarding Petal and Hattiesburg's assets held for sale.

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,	
	2011	2010	2011	2010
NGL Pipelines & Services	$ 10.3	$ 10.4	$ 30.7	$ 29.8
Onshore Natural Gas Pipelines & Services	19.5	20.1	59.6	52.4
Onshore Crude Oil Pipelines & Services	0.1	0.1	0.3	0.3
Offshore Pipelines & Services	2.8	3.1	8.6	9.7
Petrochemical & Refined Products Services	4.3	2.7	12.9	7.9
Total	$ 37.0	$ 36.4	$ 112.1	$ 100.1

The following table presents forecast amortization expense associated with existing intangible assets for the years presented:

Remainder of 2011	2012	2013	2014	2015
$ 33.4	$ 130.3	$ 126.2	$ 125.1	$ 122.2

In general, our intangible assets fall within two categories – customer relationship and contract-based intangible assets. The values assigned to such intangible assets are amortized to earnings using either (i) a straight-line approach or (ii) other methods that closely resemble the pattern in which the economic benefits of associated resource bases are estimated to be consumed or otherwise used, as appropriate.

Customer relationship intangible assets. Customer relationship intangible assets represent the estimated economic value assigned to certain relationships acquired in connection with business combinations and asset purchases whereby (i) we acquired information about or access to customers and now have regular contact with them and (ii) the customers now have the ability to make direct contact with us. Customer relationships may arise from contractual arrangements (such as supplier contracts and service contracts) and through means other than contracts, such as through regular contact by sales or service representatives. At September 30, 2011, the carrying value of our customer relationship intangible assets was $1.35 billion.

Contract-based intangible assets. Contract-based intangible assets represent specific commercial rights we acquired in connection with business combinations or asset purchases. At September 30, 2011, the carrying value of our contract-based intangible assets was $341.0 million.

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing at the beginning of each fiscal year, and more frequently, if circumstances indicate it is probable that the fair value of goodwill is below its carrying amount. The following table presents changes in the carrying amount of goodwill for the period presented:

	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Consolidated Total
Balance at December 31, 2010 (1)	$ 341.2	$ 311.1	$ 311.2	$ 82.1	$ 1,062.1	$ 2,107.7
Goodwill adjustment (2)	--	--	--	--	(0.6)	(0.6)
Reclassification of Crystal goodwill to assets held for sale (3)	--	(14.8)	--	--	--	(14.8)
Balance at September 30, 2011 (1)	$ 341.2	$ 296.3	$ 311.2	$ 82.1	$ 1,061.5	$ 2,092.3

(1) The total carrying amount of goodwill at September 30, 2011 and December 31, 2010 is presented net of $1.3 million of accumulated impairment charges.
(2) The goodwill we recorded in connection with a marine business acquisition completed in November 2010 was subsequently reduced by $0.6 million in May 2011 due to a purchase price adjustment.
(3) See Note 6 for information related to the reclassification of Petal and Hattiesburg's goodwill to assets held for sale.

Goodwill impairment testing involves determining the fair value of the associated reporting unit. These fair value amounts are based on assumptions regarding the future economic prospects of the businesses that make up the reporting unit. Such assumptions include (i) discrete financial forecasts for the businesses contained within the reporting unit, which rely on management's estimates of operating margins, throughput volumes and similar factors; (ii) long-term growth rates for cash flows beyond the discrete forecast period; and (iii) appropriate discount rates. Based on our most recent goodwill impairment tests, each reporting unit's fair value was substantially in excess of its carrying value (i.e., by at least 10%).

Note 10. Debt Obligations

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

	September 30, 2011	December 31, 2010
EPO senior debt obligations:		
Senior Notes B, 7.50% fixed-rate, due February 2011	$ --	$ 450.0
Senior Notes S, 7.625% fixed-rate, due February 2012	490.5	490.5
Senior Notes P, 4.60% fixed-rate, due August 2012	500.0	500.0
$1.75 Billion Multi-Year Revolving Credit Facility, variable-rate, due November 2012	--	648.0
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 AA, 3.20% fixed-rate, due February 2016	750.0	--
$3.5 Billion Multi-Year Revolving Credit Facility, variable-rate, due September 2016	720.0	--
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	--
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0	500.0
Petal GO Zone Bonds, variable-rate, due August 2034 (1)	--	57.5
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	--
Senior Notes DD, 5.70% fixed-rate, due February 2042	600.0	--
TEPPCO senior debt obligations:		
TEPPCO Senior Notes, 7.625% fixed-rate, due February 2012	9.5	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
Duncan Energy Partners' debt obligations:		
DEP Term Loan, variable-rate, due December 2011	--	282.3
DEP $850 Million Multi-Year Revolving Credit Facility, variable-rate, due October 2013	--	106.0
DEP $400 Million Term Loan Facility, variable-rate, due October 2013	--	400.0
Total principal amount of senior debt obligations	13,520.0	11,993.8
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	15,052.7	13,526.5
Other, non-principal amounts:		
Change in fair value of debt hedged in fair value hedging relationship (2)	81.5	49.3
Unamortized discounts, net of premiums	(30.4)	(24.0)
Unamortized deferred net gains related to terminated interest rate swaps (2)	4.9	11.7
Total other, non-principal amounts	56.0	37.0
Less current maturities of debt (3)	(1,000.0)	(282.3)
Total long-term debt	$ 14,108.7	$ 13,281.2

(1) See Note 6 for information concerning the reclassification of Petal GO Zone Bonds to liabilities related to assets held for sale.
(2) See Note 4 for information regarding our interest rate hedging activities.
(3) We expect to refinance the current maturities of our debt obligations prior to their maturity.

Letters of Credit

At September 30, 2011, EPO had $87.5 million in letters of credit outstanding related to its commodity derivative instruments and a $58.3 million letter of credit outstanding related to its Petal GO Zone Bonds. These letter of credit facilities do not reduce the amount available for borrowing under EPO's $3.5 Billion Multi-Year Revolving Credit Facility.

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 repayment of that obligation.

Debt Obligations

Apart from that discussed below and routine fluctuations in the balance of our consolidated revolving credit facilities, there have been no significant changes in the terms or amounts of our consolidated debt obligations since those reported in our 2010 Form 10-K.

$3.5 Billion Multi-Year Revolving Credit Facility. In September 2011, EPO entered into a new $3.5 billion variable-rate multi-year revolving credit facility that matures in September 2016. Initial borrowings under this credit facility were used to refinance and terminate EPO's prior $1.75 billion multi-year revolving credit facility. Future borrowings under the new credit facility may be used for working capital, capital expenditures, acquisitions and general partnership purposes.

As defined by the credit agreement, variable interest rates charged under this facility bear interest at a LIBOR rate plus an applicable margin. In addition, EPO is required to pay a quarterly facility fee on each lender's commitment irrespective of commitment usage. This revolving credit facility allows us to request up to two one-year extensions of the maturity date, subject to lender approval. The total amount of the bank commitments may be increased, without the consent of the lenders, by an amount not exceeding $500 million by adding one or more lenders to the facility and/or requesting that the commitments of existing lenders be increased.

The revolving credit facility contains certain financial and other customary affirmative and negative covenants. The credit agreement also restricts EPO's ability to pay cash distributions to Enterprise Products Partners L.P. if a default or an event of default (as defined in the credit agreement) has occurred and is continuing at the time such distribution is scheduled to be paid. EPO's borrowings under this agreement are unsecured general obligations that are non-recourse to Enterprise GP.

Issuance of Senior Notes CC and DD. In August 2011, EPO issued $650.0 million in principal amount of 10-year unsecured Senior Notes CC and $600.0 million in principal amount of 30-year unsecured Senior Notes DD. Senior Notes CC were issued at 99.790% of their principal amount, have a fixed interest rate of 4.05% and mature on February 15, 2022. Senior Notes DD were issued at 99.887% of their principal amount, have a fixed interest rate of 5.70% and mature on February 15, 2042. Net proceeds from the issuance of Senior Notes CC and DD were used (i) to temporarily reduce borrowings outstanding under $1.75 Billion EPO's Multi-Year Revolving Credit Facility and (ii) for general company purposes.

EPO's senior fixed-rate notes are unsecured obligations of EPO and rank equal with its existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. EPO's senior notes are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict its ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

Issuance of Senior Notes AA and BB. In January 2011, EPO issued $750.0 million in principal amount of 5-year unsecured Senior Notes AA and $750.0 million in principal amount of 30-year unsecured

Senior Notes BB. Senior Notes AA were issued at 99.901% of their principal amount, have a fixed interest rate of 3.20% and mature on February 1, 2016. Senior Notes BB were issued at 99.317% of their principal amount, have a fixed interest rate of 5.95% and mature on February 1, 2041. Net proceeds from the issuance of Senior Notes AA and BB were used (i) to repay $450.0 million in aggregate principal amount of Senior Notes B that matured in February 2011, (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general company purposes.

Cancellation of Canadian Revolving Credit Facility. This facility was cancelled in January 2011. As of December 31, 2010, there were no debt obligations outstanding under this $30 million revolving credit facility.

Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at September 30, 2011.

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 obligations during the nine months ended September 30, 2011:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
EPO $1.75 Billion Multi-Year Revolving Credit Facility	0.69% to 3.25%	0.79%
EPO $3.5 Billion Multi-Year Revolving Credit Facility	1.60% to 3.63%	1.60%
DEP Term Loan	1.06% to 1.42%	1.21%
DEP $850 Million Multi-Year Revolving Credit Facility	2.01% to 2.43%	2.22%
DEP $400 Million Term Loan Facility	2.26% to 2.97%	2.55%
Petal GO Zone Bonds	0.06% to 0.33%	0.20%

Consolidated Debt Maturity Table

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

		Scheduled Maturities of Debt				
	Total	2012	2013	2014	2015	After 2015
Revolving Credit Facility	$ 720.0	$ --	$ --	$ --	$ --	$ 720.0
Senior Notes	12,800.0	1,000.0	1,200.0	1,150.0	650.0	8,800.0
Junior Subordinated Notes	1,532.7	--	--	--	--	1,532.7
Total	$ 15,052.7	$ 1,000.0	$ 1,200.0	$ 1,150.0	$ 650.0	$ 11,052.7

Debt Obligations of Unconsolidated Affiliates

At September 30, 2011, we had two privately held unconsolidated affiliates – Poseidon and Centennial – with long-term debt obligations. The following table shows (i) our ownership interest in each entity at September 30, 2011, (ii) the total debt of each entity at September 30, 2011 (on a 100% basis to the unconsolidated affiliate) and (iii) the corresponding scheduled maturities of such debt.

			Scheduled Maturities of Debt					
	Ownership Interest	Total	Remainder of 2011	2012	2013	2014	2015	After 2015
Poseidon	36%	$ 92.0	$ --	$ --	$ --	$ --	$ 92.0	$ --
Centennial	50%	104.2	2.3	8.9	8.6	8.6	8.6	67.2
Total		$ 196.2	$ 2.3	$ 8.9	$ 8.6	$ 8.6	$ 100.6	$ 67.2

The credit agreements of Poseidon and Centennial include customary financial and other covenants. These businesses were in compliance with such financial covenants at September 30, 2011. The credit agreements of these unconsolidated affiliates restrict their ability to pay cash dividends or distributions if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend or distribution is scheduled to be paid.

In March 2011, Evangeline made the final scheduled payment of $3.2 million on its subordinated note payable. Following this payment, Evangeline no longer has any debt obligations.

Poseidon refinanced its revolving credit facility in April 2011. The new replacement facility matures in April 2015 and has a borrowing capacity of $125 million, which may be increased to a maximum of $175 million at Poseidon's option.

For information regarding Energy Transfer Equity's debt obligations, go to www.sec.gov for the registrant's periodic reports.

Note 11. Equity and Distributions

Partners' Equity

Pre-Holdings Merger. As discussed in Note 1, the historical comparative financial statements presented herein are the financial statements of Holdings for periods prior to the effective date of the Holdings Merger. The following table summarizes changes in the number of Holdings' limited partner Units outstanding during the nine months ended September 30, 2010:

Balance, January 1, 2010	139,191,640
Issuance of Units to directors of the general partner of Holdings	3,424
Balance, September 30, 2010	139,195,064

Post-Holdings Merger. On November 22, 2010, the 139,195,064 Holdings Units outstanding at the effective date of the Holdings Merger were converted into Enterprise common units at a ratio of 1.5 to one and, as a result, Holdings' unitholders received 208,813,454 Enterprise common units (net of 23 fractional Enterprise common units that were cashed out).

In addition, the historical noncontrolling interests of Holdings related to limited partner interests in Enterprise that were owned by third parties and related parties other than Holdings was reclassified to limited partners' equity at the effective date of the Holdings Merger. See "Noncontrolling Interests" below for information regarding our noncontrolling interest holders. Following the Holdings Merger, our partners' equity reflects the various classes of limited partner interests of Enterprise (e.g., common units (including restricted common units) and Class B units).

Post-Duncan Merger. On September 7, 2011, the 24,036,950 Duncan Energy Partners common units outstanding, other than those beneficially owned by EPO, at the effective date of the Duncan Merger were converted into Enterprise common units at a ratio of 1.01 to one and, as a result, Duncan Energy Partners' unitholders received 24,277,310 Enterprise common units (net of 9 fractional Enterprise common units that were cashed out) as consideration in the Duncan Merger. No Enterprise common units were issued to Enterprise or its subsidiaries as merger consideration.

The following table summarizes changes in the number of Enterprise's outstanding units since December 31, 2010:

	Common Units	Class B Units	Treasury Units
Balance, December 31, 2010	843,681,572	4,520,431	--
Common units issued in connection with Duncan Merger	24,277,310	--	--
Common units issued in connection with DRIP and EUPP	1,694,292	--	--
Restricted common units issued	1,381,530	--	--
Forfeiture of restricted common units	(129,899)	--	--
Acquisition of treasury units in connection with equity-based awards	(241,432)	--	241,432
Cancellation of treasury units	--	--	(241,432)
Other	(14,302)	--	--
Balance, September 30, 2011	870,649,071	4,520,431	--

The Class B units are not entitled to receive regular quarterly cash distributions for the first sixteen quarters following the closing date of the TEPPCO Merger in October 2009. The Class B units 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 merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as our common units.

During the nine months ended September 30, 2011, 886,508 restricted common unit awards vested and converted to common units. Of this amount, 241,432 were sold back to us by employees to cover related withholding tax requirements. We cancelled such treasury units immediately upon acquisition.

We may issue additional equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. In July 2010, Enterprise, including EPO, filed a universal shelf registration statement (the "2010 Shelf") with the SEC. The 2010 Shelf allows Enterprise 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 AA and BB in January 2011 and Senior Notes CC and DD in August 2011 (see Note 10).

Enterprise also has a registration statement on file with the SEC in connection with its distribution reinvestment plan ("DRIP"). After taking into account limited partner units issued under this registration statement through September 30, 2011, Enterprise may issue an additional 26,806,721 common units under its DRIP. The following table reflects the number of common units issued and the net cash proceeds received from Enterprise's DRIP during the nine months ended September 30, 2011:

	Number of Common Units Issued	Net Cash Proceeds
February 2011 issuance	474,706	$ 19.6
May 2011 issuance	551,058	21.9
August 2011 issuance	582,387	22.0
Total	1,608,151	$ 63.5

In May 2011, Enterprise's original employee unit purchase plan ("EUPP") reached the maximum 1,200,000 common units permitted under the plan and was terminated. A total of 86,141 common units were issued in 2011 under the EUPP, which generated net cash proceeds of $3.6 million.

In September 2011, in connection with the Duncan Merger, the Duncan Energy Partners EUPP was assumed by Enterprise and converted into a new Enterprise EUPP. Enterprise filed a registration statement with the SEC authorizing the issuance of 440,879 common units under the assumed plan. As of September 30, 2011, Enterprise had not issued any of its common units under this plan.

Net cash proceeds received from Enterprise's DRIP and terminated EUPP were used to temporarily reduce borrowings outstanding under EPO's revolving credit facilities and for general partnership purposes.

Accumulated Other Comprehensive Income (Loss)

Our accumulated other comprehensive income (loss) amounts primarily include the effective portion of the gain or loss on derivative instruments designated and qualified as cash flow hedges. Amounts accumulated in other comprehensive income (loss) related to cash flow hedges are reclassified into 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) must be immediately reclassified into earnings.

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, 2011	December 31, 2010
Commodity derivative instruments (1)	$ (32.2)	$ (31.8)
Interest rate derivative instruments (1)	(303.6)	(2.1)
Foreign currency translation adjustment (2)	1.7	1.7
Pension and postretirement benefit plans	(1.0)	(0.4)
Proportionate share of other comprehensive loss of Energy Transfer Equity	(1.7)	(1.0)
Subtotal	(336.8)	(33.6)
Amounts attributable to noncontrolling interests	--	1.1
Total accumulated other comprehensive loss in partners' equity	$ (336.8)	$ (32.5)

(1) See Note 4 for additional information regarding these components of accumulated other comprehensive income (loss).
(2) Relates to transactions of our Canadian NGL marketing subsidiary.

Noncontrolling Interests

For periods prior to the Holdings Merger, the portion of the income of Enterprise attributable to its limited partner interests owned by third parties and related parties other than Holdings is included in net income attributable to noncontrolling interests as presented on our Unaudited Condensed Statements of Consolidated Operations. Additionally, cash distributions paid to and cash contributions received from the limited partners of Enterprise other than Holdings are reflected as a component of cash distributions paid to and cash contributions received from noncontrolling interests, as appropriate.

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

	September 30, 2011	December 31, 2010
Former owners of Duncan Energy Partners	$ --	$ 412.1
Joint venture partners (1)	112.8	115.6
Accumulated other comprehensive loss attributable to noncontrolling interests	--	(1.1)
Total noncontrolling interests	$ 112.8	$ 526.6

(1) Represents third-party ownership interests in joint ventures that we consolidate, including Seminole Pipeline Company, 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,	
	2011	2010	2011	2010
Limited partners of Enterprise	$ --	$ 296.6	$ --	$ 887.3
Former owners of Duncan Energy Partners	3.6	8.5	20.9	26.8
Joint venture partners	4.5	5.5	15.8	19.3
Total	$ 8.1	$ 310.6	$ 36.7	$ 933.4

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,	
	2011	2010
Cash distributions paid to noncontrolling interests:		
Limited partners of Enterprise	$ --	$ 1,045.0
Former owners of Duncan Energy Partners	32.9	32.1
Joint venture partners	19.1	21.9
Total cash distributions paid to noncontrolling interests	$ 52.0	$ 1,099.0
Cash contributions from noncontrolling interests:		
Limited partners of Enterprise	$ --	$ 1,031.6
Former owners of Duncan Energy Partners	2.6	1.2
Joint venture partners	2.1	1.6
Total cash contributions from noncontrolling interests	$ 4.7	$ 1,034.4

Cash distributions paid to the limited partners of Enterprise (prior to the Holdings Merger) and former owners of Duncan Energy Partners represent the quarterly cash distributions paid by these entities to their unitholders, excluding amounts paid to Holdings that were eliminated in the preparation of our consolidated financial statements. Similarly, cash contributions received from the limited partners of Enterprise (prior to the Holdings Merger) and former owners of Duncan Energy Partners represent net cash proceeds each entity received from the issuance of limited partner units, excluding contributions made by Holdings that were eliminated in consolidation.

Cash Distributions

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

	Distribution Per Common Unit	Record Date	Payment Date
2011			
1st Quarter	$ 0.5975	04/29/11	05/06/11
2nd Quarter	$ 0.6050	07/29/11	08/10/11
3rd Quarter	$ 0.6125	10/31/11	11/09/11

The quarterly cash distributions paid on May 6, 2011, August 10, 2011 and November 9, 2011 exclude 30,610,000 Designated Units (see Note 1).

Note 12. Business Segments

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

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our 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 (e.g., the EPCO retained leases); (iv) gains and losses from asset sales and related transactions; 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, provision for 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.

The following table shows our measurement of total segment gross operating margin for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
Revenues	$ 11,327.1	$ 8,067.8	$ 32,727.3	$ 24,155.7
Less: Operating costs and expenses	(10,604.6)	(7,460.1)	(30,675.0)	(22,406.2)
Add: Equity in income of unconsolidated affiliates	8.6	5.6	35.9	43.2
Depreciation, amortization and accretion in operating costs and expenses (1)	238.3	235.1	702.4	674.5
Non-cash asset impairment charges	5.2	--	5.2	1.5
Operating lease expenses paid by EPCO	--	0.2	0.3	0.5
Gains from asset sales and related transactions in operating costs and expenses (2)	(1.8)	(39.7)	(25.4)	(45.3)
Total segment gross operating margin	$ 972.8	$ 808.9	$ 2,770.7	$ 2,423.9

(1) Amount is a component of “Depreciation, amortization and accretion” as presented on the Unaudited Condensed Statements of Consolidated Cash Flows.
(2) Amount is a component of “Gains from asset sales and related transactions” as presented on the Unaudited Condensed Statements of Consolidated Cash Flows.

The following table presents a reconciliation of total segment gross operating margin to operating income and further to income before provision for income taxes for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
Total segment gross operating margin	$ 972.8	$ 808.9	$ 2,770.7	$ 2,423.9
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(238.3)	(235.1)	(702.4)	(674.5)
Non-cash asset impairment charges	(5.2)	--	(5.2)	(1.5)
Operating lease expenses paid by EPCO	--	(0.2)	(0.3)	(0.5)
Gains from asset sales and related transactions in operating costs and expenses	1.8	39.7	25.4	45.3
General and administrative costs	(50.0)	(70.1)	(138.3)	(150.9)
Operating income	681.1	543.2	1,949.9	1,641.8
Other expense, net	(190.0)	(190.7)	(561.3)	(527.3)
Income before provision for income taxes	$ 491.1	$ 352.5	$ 1,388.6	$ 1,114.5

Information by business segment, together with reconciliations to our consolidated 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, 2011	$ 4,323.8	$ 855.9	$ 3,957.1	$ 57.7	$ 1,968.7	$ --	$ --	$ 11,163.2
Three months ended September 30, 2010	3,169.3	781.8	2,726.0	68.3	1,188.7	--	--	7,934.1
Nine months ended September 30, 2011	12,339.3	2,590.1	11,609.3	179.4	5,451.0	--	--	32,169.1
Nine months ended September 30, 2010	9,759.4	2,679.1	7,742.0	240.3	3,252.8	--	--	23,673.6
Revenues from related parties:								
Three months ended September 30, 2011	94.7	66.8	--	2.4	--	--	--	163.9
Three months ended September 30, 2010	65.2	66.1	(0.1)	2.5	--	--	--	133.7
Nine months ended September 30, 2011	372.9	176.5	--	8.8	--	--	--	558.2
Nine months ended September 30, 2010	300.7	175.2	(0.2)	6.4	--	--	--	482.1
Intersegment and intrasegment revenues:								
Three months ended September 30, 2011	3,253.6	257.2	1,342.2	4.8	442.9	--	(5,300.7)	--
Three months ended September 30, 2010	2,378.1	261.0	313.4	0.5	309.7	--	(3,262.7)	--
Nine months ended September 30, 2011	9,956.4	782.0	3,526.9	6.6	1,361.5	--	(15,633.4)	--
Nine months ended September 30, 2010	7,333.0	689.3	561.5	1.2	854.7	--	(9,439.7)	--
Total revenues:								
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
Three months ended September 30, 2010	5,612.6	1,108.9	3,039.3	71.3	1,498.4	--	(3,262.7)	8,067.8
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
Nine months ended September 30, 2010	17,393.1	3,543.6	8,303.3	247.9	4,107.5	--	(9,439.7)	24,155.7
Equity in income (loss) of unconsolidated affiliates:								
Three months ended September 30, 2011	4.3	1.4	(1.0)	5.4	(3.8)	2.3	--	8.6
Three months ended September 30, 2010	5.1	1.2	1.6	10.1	(0.5)	(11.9)	--	5.6
Nine months ended September 30, 2011	16.4	4.1	(3.1)	20.3	(13.1)	11.3	--	35.9
Nine months ended September 30, 2010	12.1	3.4	7.5	33.0	(5.8)	(7.0)	--	43.2
Gross operating margin:								
Three months ended September 30, 2011	547.6	156.0	67.4	53.9	145.6	2.3	--	972.8
Three months ended September 30, 2010	397.2	154.1	35.0	68.3	166.2	(11.9)	--	808.9
Nine months ended September 30, 2011	1,549.7	476.3	167.0	168.6	397.8	11.3	--	2,770.7
Nine months ended September 30, 2010	1,275.5	391.3	87.6	232.2	444.3	(7.0)	--	2,423.9
Segment assets:								
At September 30, 2011	7,728.2	7,948.6	940.1	2,023.1	3,768.7	1,076.8	3,590.0	27,075.5
At December 31, 2010	7,665.5	8,184.8	917.5	2,004.9	3,758.7	1,436.8	1,607.2	25,575.4
Property, plant and equipment, net: (see Note 7)								
At September 30, 2011	6,909.4	6,476.0	449.9	1,432.0	2,530.8	--	3,590.0	21,388.1

At December 31, 2010	6,813.1	6,595.0	427.9	1,390.9	2,498.8	--	1,607.2	19,332.9
Investments in unconsolidated affiliates: (see Note 8)								
At September 30, 2011	130.4	31.0	173.1	428.9	68.3	1,076.8	--	1,908.5
At December 31, 2010	131.5	32.6	172.2	443.2	76.8	1,436.8	--	2,293.1
Intangible assets, net: (see Note 9)								
At September 30, 2011	347.2	1,145.3	5.9	80.1	108.1	--	--	1,686.6
At December 31, 2010	379.7	1,246.1	6.2	88.7	121.0	--	--	1,841.7
Goodwill: (see Note 9)								
At September 30, 2011	341.2	296.3	311.2	82.1	1,061.5	--	--	2,092.3
At December 31, 2010	341.2	311.1	311.2	82.1	1,062.1	--	--	2,107.7

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
NGL Pipelines & Services:				
Sales of NGLs	$ 4,163.9	$ 3,048.0	$ 12,052.5	$ 9,516.5
Sales of other petroleum and related products	1.0	0.6	2.3	1.8
Midstream services	253.6	185.9	657.4	541.8
Total	4,418.5	3,234.5	12,712.2	10,060.1
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	704.7	651.0	2,136.9	2,281.8
Midstream services	218.0	196.9	629.7	572.5
Total	922.7	847.9	2,766.6	2,854.3
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	3,929.8	2,701.4	11,535.9	7,672.1
Midstream services	27.3	24.5	73.4	69.7
Total	3,957.1	2,725.9	11,609.3	7,741.8
Offshore Pipelines & Services:				
Sales of natural gas	0.3	0.2	0.9	1.0
Sales of crude oil	1.3	2.3	7.1	6.3
Midstream services	58.5	68.3	180.2	239.4
Total	60.1	70.8	188.2	246.7
Petrochemical & Refined Products Services:				
Sales of other petroleum and related products	1,767.2	1,056.3	4,868.7	2,860.6
Midstream services	201.5	132.4	582.3	392.2
Total	1,968.7	1,188.7	5,451.0	3,252.8
Total consolidated revenues	$ 11,327.1	$ 8,067.8	$ 32,727.3	$ 24,155.7
Consolidated costs and expenses				
Operating costs and expenses:				
Cost of sales related to our marketing activities	$ 8,712.4	$ 6,234.5	$ 25,370.0	$ 18,577.2
Depreciation, amortization and accretion	238.3	235.1	702.4	674.5
Gains from asset sales and related transactions	(1.8)	(39.7)	(25.4)	(45.3)
Non-cash asset impairment charges	5.2	--	5.2	1.5
Other operating costs and expenses	1,650.5	1,030.2	4,622.8	3,198.3
General and administrative costs	50.0	70.1	138.3	150.9
Total consolidated costs and expenses	$ 10,654.6	$ 7,530.2	$ 30,813.3	$ 22,557.1

Changes in our revenues and operating costs and expenses period-to-period are explained in part by changes in energy commodity prices. In general, higher energy commodity prices result in an increase in our revenues attributable to the sale of NGLs, natural gas, crude oil and other petroleum and related products; however, these higher commodity prices also increase the associated cost of sales as purchase costs rise.

Note 13. 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,	
	2011	2010	2011	2010
Revenues – related parties:				
Energy Transfer Equity and subsidiaries	$ 95.8	$ 66.2	$ 392.7	$ 312.7
Other unconsolidated affiliates	68.1	67.5	165.5	169.4
Total revenue – related parties	$ 163.9	$ 133.7	$ 558.2	$ 482.1
Costs and expenses – related parties:				
EPCO and affiliates	$ 187.8	$ 201.3	$ 553.2	$ 525.7
Energy Transfer Equity and subsidiaries	278.8	172.6	769.2	496.7
Other unconsolidated affiliates	21.8	10.4	43.4	32.1
Total costs and expenses – related parties	$ 488.4	$ 384.3	$ 1,365.8	$ 1,054.5

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

	September 30, 2011	December 31, 2010
Accounts receivable - related parties:		
Energy Transfer Equity and subsidiaries	$ 20.0	$ 21.4
Other unconsolidated affiliates	17.5	15.4
Total accounts receivable – related parties	$ 37.5	$ 36.8
Accounts payable - related parties:		
EPCO and affiliates	$ 111.4	$ 88.0
Energy Transfer Equity and subsidiaries	87.2	36.7
Other unconsolidated affiliates	13.6	8.4
Total accounts payable – related parties	$ 212.2	$ 133.1

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties.

Relationship with EPCO and Affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities that are not a part of our consolidated group of companies:

§ EPCO and its privately held affiliates; and

§ Enterprise GP, our sole general partner.

EPCO is a privately held company controlled collectively by the EPCO Trustees. At September 30, 2011, EPCO and its affiliates (including Dan Duncan LLC and two 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 Outstanding Units
338,930,881 (1)	38.7%

(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 separate from those of EPCO and its other affiliates. EPCO and its privately held affiliates depend on the cash distributions they receive from us (including Holdings prior to the Holdings Merger) and other investments to fund their other operations and to meet their debt obligations. The following table presents cash distributions received by EPCO and its privately held affiliates from us and Holdings for the periods presented:

	For the Nine Months Ended September 30,	
	2011	2010
Enterprise	$ 522.8	$ 255.1
Holdings	--	176.6
Total distributions	$ 522.8	$ 431.7

Substantially all of the ownership interests in us that are owned or controlled by EPCO and its affiliates, other than those interests owned by Dan Duncan LLC and certain trusts of which the estate of Mr. Duncan is a beneficiary, are pledged as security under the credit facility of a privately held affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including us.

We lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates.

EPCO ASA. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA or by other service providers. We and our general partner are parties to the ASA. The significant terms of the ASA are as follows:

§ EPCO will provide selling, general and administrative services and management and operating services as may be necessary to manage and operate our businesses, properties and assets (all in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel.

§ We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including expenses reasonably allocated to us by EPCO). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time with respect to the services provided to us by EPCO.

§ EPCO will allow us to participate as a named insured in its overall insurance program, with the associated premiums and other costs being allocated to us. See Note 16 for additional information regarding our insurance programs.

Under the ASA, EPCO subleased to us (for $1 per year) certain equipment it held pursuant to operating leases. EPCO was liable for the cash payments associated with these lease agreements. In June 2011, we paid $5.4 million to purchase the assets from the lessor and the lease agreements were terminated. While these lease agreements were in effect, we recorded the full value of the lease payments made by EPCO on our behalf as a non-cash related party operating expense, with the offset to equity accounted for as a general contribution to our partnership.

Our operating costs and expenses include amounts paid to EPCO for the costs it incurs to operate our facilities, including the compensation of its employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. Likewise, our general and administrative costs include amounts paid to EPCO for administrative services, including the compensation of its employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation of legal or accounting salaries based on estimates of time spent on each entity's business and affairs). The following table presents a breakout of costs and expenses related to the ASA and other EPCO transactions for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
Operating costs and expenses	$ 157.2	$ 159.4	$ 462.5	$ 434.7
General and administrative expenses	30.6	41.9	90.7	91.0
Total costs and expenses	$ 187.8	$ 201.3	$ 553.2	$ 525.7

Since the vast majority of such expenses are charged to us on an actual basis (i.e., no mark-up or subsidy is charged or received by EPCO), we believe that such expenses are representative of what the amounts would have been on a standalone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPCO is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. The following information summarizes significant related party transactions with our current unconsolidated affiliates:

§ We sell natural gas to Evangeline, which, in turn, uses the natural gas to satisfy supply commitments it has with a major Louisiana utility. Revenues from Evangeline were $54.3 million and $58.9 million for the three months ended September 30, 2011 and 2010, respectively. During the nine months ended September 30, 2011 and 2010, revenues from Evangeline were $134.6 million and $145.7 million, respectively.

§ We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. Revenues from Promix were $9.9 million and $3.7 million for the three months ended September 30, 2011 and 2010, respectively. During the nine months ended September 30, 2011 and 2010, revenues from Promix were $16.3 million and $9.9 million, respectively. Expenses with Promix were $20.9 million and $9.7 million for the three months ended September 30, 2011 and 2010, respectively. During the nine months ended September 30, 2011 and 2010, expenses with Promix were $38.6 million and $25.8 million, respectively.

§ We paid $0.2 million to Centennial for other pipeline transportation services during each of the three months ended September 30, 2011 and 2010. During the nine months ended September 30, 2011 and 2010, we paid Centennial $2.8 million and $3.1 million, respectively, for such services.

§ We paid $0.2 million and $0.8 million to Seaway for pipeline transportation and tank rentals in connection with our crude oil marketing activities during the three months ended September 30, 2011 and 2010, respectively. During the nine months ended September 30, 2011 and 2010, we paid Seaway $1.2 million and $3.5 million, respectively, for such services.

§ We paid $1.7 million and $1.5 million to White River Hub primarily for firm capacity reservation fees during the three months ended September 30, 2011 and 2010, respectively. During the nine months ended September 30, 2011 and 2010, we paid White River Hub $5.0 million and $4.4 million, respectively, of such fees.

§ We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $3.2 million and $2.9 million for the three months ended September 30, 2011 and 2010, respectively. During the nine months ended September 30, 2011 and 2010, we charged affiliates $9.6 million and $8.6 million, respectively.

§ We have a long-term sales contract with a subsidiary of Energy Transfer Equity. In addition, we and another subsidiary of ETP transport natural gas on each other's systems and share operating expenses on certain pipelines. A subsidiary of ETP also sells natural gas to us. See previous table for related party revenue and expense amounts recorded by us in connection with Energy Transfer Equity.

Note 14. Earnings Per Unit

As described below, the earnings per unit amounts presented in these consolidated financial statements have been retroactively adjusted to reflect the unit-for-unit exchange that occurred in connection with the Holdings Merger.

Basic and diluted earnings per unit amounts for periods prior to the Holdings Merger are based on net income attributable to partners divided by the weighted-average number of Holdings' units outstanding for the period multiplied by the merger exchange ratio of 1.5 Enterprise common units for each Holdings unit. Net income attributable to partners prior to the Holdings Merger represents the net income allocated to the former owners of Holdings, which excluded amounts allocated to noncontrolling interests. As described in Note 11, net income attributable to noncontrolling interests prior to the Holdings Merger included net income amounts allocated to Enterprise's limited partner interests that were owned by third parties and related parties other than Holdings.

Following the Holdings Merger, basic earnings per unit is computed by dividing net income or loss attributable to our limited partner interests by the weighted-average number of our distribution-bearing units outstanding during a period, which excludes the Designated Units (see Note 1) 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 partner interests by the sum of (i) the weighted-average number of our distribution-bearing units outstanding during a period (as used in determining basic earnings per unit), (ii) the weighted-average number of our Class B units (see Note 11) outstanding during a period, (iii) the weighted-average number of Designated Units outstanding during a period and (iv) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

In a period of net losses, the Class B units, Designated Units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. The dilutive incremental option units are calculated using the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the end of each period are used to repurchase common units at an average market price during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
BASIC EARNINGS PER UNIT				
Numerator:				
Net income attributable to partners	$ 471.4	$ 37.0	$ 1,325.8	$ 161.0
General partner interest in net income	--	*	--	*
Net income attributable to limited partners	$ 471.4	$ 37.0	$ 1,325.8	$ 161.0
Denominator:				
Common units	817.9	208.8	812.9	208.8
Time-vested restricted common units	4.0	--	4.1	--
Total	821.9	208.8	817.0	208.8
Basic earnings per unit:				
Net income attributable to partners	$ 0.57	$ 0.18	$ 1.62	$ 0.77
General partner interest in net income	--	*	--	*
Net income attributable to limited partners	$ 0.57	$ 0.18	$ 1.62	$ 0.77
DILUTED EARNINGS PER UNIT				
Numerator:				
Net income attributable to partners	$ 471.4	$ 37.0	$ 1,325.8	$ 161.0
General partner interest in net income	--	*	--	*
Net income attributable to limited partners	$ 471.4	$ 37.0	$ 1,325.8	$ 161.0
Denominator:				
Common units	817.9	208.8	812.9	208.8
Time-vested restricted common units	4.0	--	4.1	--
Class B units	4.5	--	4.5	--
Designated Units	30.6	--	30.6	--
Incremental option units	1.2	--	1.2	--
Total	858.2	208.8	853.3	208.8
Diluted earnings per unit:				
Net income attributable to partners	$ 0.55	$ 0.18	$ 1.55	$ 0.77
General partner interest in net income	--	*	--	*
Net income attributable to limited partners	$ 0.55	$ 0.18	$ 1.55	$ 0.77

* Amount is negligible

Note 15. Commitments and Contingencies

Litigation

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

Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the possible need for accounting recognition and disclosure of these contingencies. We accrue an undiscounted liability for those contingencies where the loss is probable and the amount can be reasonably estimated. If a range of 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, 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 (including the availability of insurance coverage), we do not believe the ultimate outcome of any currently pending lawsuit against us will have a material impact on our financial statements individually or in the aggregate. See Note 16 for information regarding our insurance program.

At September 30, 2011 and December 31, 2010, litigation accruals on an undiscounted basis of $12.9 million and $8.6 million, respectively, were recorded in our consolidated balance sheets as a component of other current liabilities. Our evaluation of litigation contingencies is based on the facts and circumstances of each case and predicting the outcome of these matters involves substantial 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.

Merger-Related Matters

We have completed a number of merger-related transactions in recent years that were material to our financial statements. The following discussion of litigation matters relates to these merger transactions. We do not believe that any expenditures related to such matters will be material to our financial statements.

Litigation Related to Holdings Acquisition of Ownership Interests in TEPPCO and TEPPCO GP. On February 14, 2008, Joel A. Gerber, then a purported unitholder of Holdings, filed a derivative complaint on behalf of Holdings in the Court of Chancery of the State of Delaware captioned *Joel A Gerber vs. EPE Holdings, LLC; Enterprise Products GP, LLC; EPCO, Inc.; Duncan Family Interests, Inc,; DFI GP Holdings LP; Dan L. Duncan; Michael A. Creel; Richard H. Bachmann; W. Randall Fowler; Randa Duncan Williams; O.S ("Dub") Andras; Charles E. McMahen; Edwin E. Smith and Thurmon Andress; and Enterprise GP Holdings, L.P*. The complaint names as defendants EPE Holdings, the Board of Directors of EPE Holdings, EPCO, and Dan L. Duncan and certain of his affiliates. Holdings is named as a nominal defendant. The complaint alleges that the defendants, in breach of their fiduciary duties to Holdings and its unitholders, caused Holdings to purchase in May 2007 the TEPPCO GP membership interests and TEPPCO units from Mr. Duncan's affiliates at an unfair price. The complaint also alleges that Charles E. McMahen, Edwin E. Smith and Thurmon Andress, then constituting the three members of EPE Holdings' Audit, Conflicts and Governance ("ACG") Committee, could not be considered independent because of their past relationships with Mr. Duncan. The complaint seeks relief (i) awarding damages for profits allegedly obtained by the defendants as a result of the alleged wrongdoings in the complaint and (ii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts. Management believes this lawsuit is without merit and intends to vigorously defend against it. See Note 13 for information regarding our relationship with EPCO and its affiliates.

On April 11, 2008, we filed a motion to dismiss this lawsuit. In response to the motion to dismiss, on September 15, 2008, the plaintiff filed an amended complaint. On September 29, 2008, we filed a motion to dismiss the amended complaint. The parties completed the briefing on the motion to dismiss on June 4, 2010. On February 8, 2011, the plaintiff filed a Motion for Leave to File a Second Amended and Supplemental Verified Complaint. On March 25, 2011, we filed a Brief in Opposition to the plaintiff's Motion for Leave to File a Second Amended and Supplemental Verified Complaint. In a Letter Opinion issued by Vice Chancellor Noble on September 29, 2011, on the plaintiff's motion, the court granted the plaintiff's leave to supplement the complaint by: (1) describing the Holdings Merger (see Note 1) and the entities that emerged out of it; (2) pleading a double derivative claim on behalf of Enterprise; and (3) pleading direct claims on behalf of those who held Holdings units immediately before the Holdings Merger. Otherwise, the plaintiff's motion to supplement or amend was denied by the court.

ENTERPRISE PRODUCTS PARTNERS L.P.
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Litigation Related to the TEPPCO Merger. On November 15, 2010, Joel A. Gerber filed a class action and derivative complaint in the Court of Chancery of the State of Delaware captioned *Joel A. Gerber vs. EPE Holdings, LLC; Enterprise Products GP, LLC; Enterprise Products Company; Enterprise Products Partners, L.P.; Randa Duncan Williams; O.S. ("Dub") Andras; Charles E. McMahen; Edwin E. Smith; Thurmon Andress; Richard H. Bachmann; B.W. Waycaster; Ralph H. Cunningham; W. Randall Fowler; and Randa Duncan Williams, Richard H. Bachmann, and Ralph H. Cunningham, in their capacity as Executors of the Estate of Dan L. Duncan, Deceased, and Enterprise GP Holdings, L.P*. This litigation asserts claims against Holdings, EPGP, EPCO and the then directors of EPE Holdings for breach of express and implied duties in connection with the TEPPCO Merger in October 2009 and the Holdings Merger in November 2010. The complaint also asserts claims against Mr. Duncan's estate, EPCO and Enterprise for tortious interference and unjust enrichment in connection with the above transactions. The complaint alleges that Holdings sold TEPPCO GP to Enterprise in the TEPPCO Merger at an unfair price to Holdings and that the terms of the Holdings Merger were unfair to Holdings' unitholders. The complaint also alleges that the members of EPE Holdings' ACG Committee, which approved both the TEPPCO Merger and Holdings Merger, could not be considered independent because of their past relationships with Mr. Duncan.

On December 13, 2010, we filed a motion to dismiss this lawsuit. In response to the motion to dismiss, on March 18, 2011, the plaintiff filed an amended complaint. On April 1, 2011, we filed a motion to dismiss the amended complaint. On October 7, 2011, oral argument on the motion to dismiss was held before the court.

Litigation Related to Holdings Merger. On September 9, 2010, Sanjay Israni, a purported unitholder of Holdings, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the unitholders of Holdings, captioned *Sanjay Israni v. EPE Holdings LLC, Enterprise GP Holdings L.P., Enterprise Products Company, Enterprise Products Partners L.P., Oscar S. Andras, Ralph S. Cunningham, Richard H. Bachmann, Randa Duncan Williams, Thurmon M. Andress, Charles E. McMahen, Edwin E. Smith and B.W. Waycaster* (the "Israni Complaint"). The Israni Complaint alleges, among other things, that Enterprise along with the named directors and EPCO have breached fiduciary duties in connection with the Holdings Merger and that Holdings aided and abetted in these alleged breaches of fiduciary duties. On October 18, 2010, we filed a motion to dismiss this lawsuit. On March 18, 2011, the plaintiffs filed a Stipulation and Proposed Order of Dismissal of all claims pending in that action without prejudice, with each party to bear its own costs and fees. The court granted the Stipulation and Proposed Order of Dismissal on March 18, 2011.

On September 29, 2010, Eugene Lonergan, Sr., a purported unitholder of Holdings, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the unitholders of Holdings, captioned *Eugene Lonergan, Sr. v. EPE Holdings LLC, Enterprise GP Holdings L.P., Oscar S. Andras, Ralph S. Cunningham, Richard H. Bachmann, Randa Duncan Williams, Thurmon M. Andress, Charles E. McMahen, Edwin E. Smith and B.W. Waycaster* (the "Lonergan Complaint"). The Lonergan Complaint alleges that the named directors and EPE Holdings breached the implied contractual covenant of good faith and fair dealing, including failing to make adequate disclosures, in connection with the Holdings Merger. On October 8, 2010, the court held a hearing on a motion by the plaintiff to expedite the proceedings. On October 11, 2010, the motion was denied. On October 18, 2010, we filed a motion to dismiss this lawsuit. On March 18, 2011, the plaintiffs filed a Stipulation and Proposed Order of Dismissal of all claims pending in that action without prejudice, with each party to bear its own costs and fees. The court granted the Stipulation and Proposed Order of Dismissal on March 18, 2011.

Additionally, on September 23, 2010, Richard Fouke, a purported unitholder of Holdings, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the unitholders of Holdings, captioned *Richard Fouke v. EPE Holdings LLC, Enterprise GP Holdings L.P., Enterprise Products Company, Enterprise Products Partners L.P., Enterprise Products GP, LLC, Oscar S. Andras, Ralph S. Cunningham, Richard H. Bachmann, Randa Duncan Williams, Thurmon M. Andress, Charles E. McMahen, Edwin E. Smith and B.W. Waycaster* (the "Fouke Complaint"). The Fouke Complaint alleges, among other things, that Enterprise, along with the named directors, EPE Holdings, EPGP and EPCO breached the implied contractual covenant of good faith and fair dealing in connection with the Holdings Merger and that Holdings and the other defendants aided and abetted in the alleged breach. On October 18, 2010, we filed a motion to dismiss this lawsuit. On July 12, 2011, the court entered a stipulation and order of dismissal of the Fouke Complaint filed by the parties dismissing the claims without prejudice.

Litigation Related to the Duncan Merger. On March 8, 2011, Michael Crowley, a purported unitholder of Duncan Energy Partners, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the public unitholders of Duncan Energy Partners, captioned *Michael Crowley v. Duncan Energy Partners L.P., DEP Holdings, LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard S. Snell, Enterprise Products Partners L.P., Enterprise Products Holdings LLC, and Enterprise Products Operating LLC* (the "Crowley Complaint"). The Crowley Complaint alleges, among other things, that the named directors of DEP GP have breached fiduciary duties in connection with the Duncan Merger (see Note 1), that Duncan Energy Partners and DEP GP aided and abetted in these alleged breaches of fiduciary duties and that we, as the majority and controlling unitholder, along with EPO, have breached fiduciary duties by not acting in the minority unitholders' best interests to ensure the transaction was entirely fair.

On March 11, 2011, Sanjay Israni, a purported unitholder of Duncan Energy Partners, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the public unitholders of Duncan Energy Partners, captioned *Sanjay Israni v. Duncan Energy Partners L.P., DEP Holdings, LLC, Enterprise Products Partners L.P., Enterprise Product Holdings LLC, Enterprise Production Operating LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, and Richard S. Snell* (the "Israni Complaint II"). The Israni Complaint II alleges, among other things, that the named directors of DEP GP have breached fiduciary duties in connection with the Duncan Merger and that we, along with all of the other named defendants aided and abetted in these alleged breaches of fiduciary duties.

On March 28, 2011, Michael Rubin, a purported unitholder of Duncan Energy Partners, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the public unitholders of Duncan Energy Partners, captioned *Michael Rubin v. Duncan Energy Partners L.P., DEP Holdings, LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard S. Snell, Enterprise Products Partners L.P., Enterprise Products Holdings LLC, and Enterprise Products Operating LLC* (the "Rubin Complaint"). The Rubin Complaint alleges, among other things, that the named directors of DEP GP have breached fiduciary duties in connection with the Duncan Merger, that Duncan Energy Partners and DEP GP aided and abetted in these alleged breaches of fiduciary duties and that we, as the majority and controlling unitholder, along with EPO, have breached fiduciary duties by not acting in the best interests of the minority unitholders to ensure the transaction was entirely fair.

On April 5, 2011, the plaintiffs in the Crowley Complaint, the Israni Complaint II, and the Rubin Complaint filed a Proposed Order of Consolidation and Appointment of Lead Counsel in the Court of Chancery of the State of Delaware. The court granted that order on the same day consolidating the three actions into a single consolidated action, captioned *In re Duncan Energy Partners L.P. Unitholders Litigation*. On June 3, 2011 the Delaware plaintiffs filed a consolidated amended complaint which alleges, among other things, breach of express and implied contractual duties contained in Duncan Energy Partners' partnership agreement by DEP GP and the named directors of DEP GP and that all defendants have aided and abetted these alleged breaches. The consolidated amended complaint also alleges that the defendants failed to provide full and fair disclosures regarding the proposed transaction. On October 14, 2011, the plaintiffs filed a Stipulation and Proposed Order of Dismissal and the case was dismissed on October 17, 2011.

On March 7, 2011, Merle Davis, a purported unitholder of Duncan Energy Partners, filed a petition in the 269th District Court of Harris County, Texas, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned *Merle Davis, on Behalf of Himself and All Others Similarly Situated v. Duncan Energy Partners L.P., W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard S. Snell, DEP Holdings, LLC, and Enterprise Products Partners L.P.* (the "Davis Petition"). The Davis Petition alleges, among other things, that we and the named directors of DEP GP have breached fiduciary duties in connection with the Duncan Merger and that we and Duncan Energy Partners aided and abetted in these alleged breaches of fiduciary duties.

On March 9, 2011, Donald Weilersbacher, a purported unitholder of Duncan Energy Partners, filed a petition in the 334th District Court of Harris County, Texas, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned *Donald Weilersbacher, on Behalf of Himself and All Others Similarly Situated v. Duncan Energy Partners L.P., Enterprise Products Partners L.P., DEP Holdings, LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, and Richard S. Snell* (the "Weilersbacher Petition"). The Weilersbacher Petition alleges, among other things, that the named directors of DEP GP have breached fiduciary duties in connection with the Duncan Merger and that we aided and abetted in these alleged breaches of fiduciary duties.

On March 17, 2011, the plaintiffs in the Davis Petition and the Weilersbacher Petition filed a motion and proposed Order for Consolidation of Related Actions, Appointment of Interim Co-Lead Counsel, and Order Compelling Limited Expedited Discovery. Plaintiffs and defendants subsequently agreed to postpone discovery until after the plaintiffs file a consolidated petition. On March 28, 2011, the plaintiffs filed an amended motion and proposed Order for Consolidation of Related Actions and Appointment of Interim Co-Lead Counsel. On May 4, 2011, the court entered an order consolidating the cases and appointing interim lead counsel. On May 11, 2011, the plaintiffs filed their consolidated petition. On June 23, 2011, the plaintiffs filed a Notice of Nonsuit Without Prejudice and the cases were dismissed without prejudice.

On July 5, 2011, Merle Davis and Donald Weilersbacher, purported unitholders of Duncan Energy Partners, filed a complaint in the United States District Court of the Southern District of Texas, Houston Division, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned *Merle Davis and Donald Weilersbacher, on Behalf of Themselves and All Others Similarly Situated vs. Duncan Energy Partners, L.P., W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard Snell, DEP Holdings, LLC, and Enterprise Products Partners L.P*. (the "Davis/Weilersbacher Federal Complaint"). The Davis/Weilersbacher Federal Complaint alleged, among other things, that Duncan Energy Partners, DEP GP and the named directors of DEP GP breached express and implied contractual duties in connection with the Duncan Merger, that all defendants aided and abetted in these alleged breaches, and that we and Duncan Energy Partners violated Section 14(a) and Section 20(a) of the Exchange Act. The plaintiff's filed a Stipulation of Dismissal Without Prejudice, which was signed by the court on August 24, 2011.

On August 3, 2011, John Rinker and Arthur H. Speier, purported unitholders of Duncan Energy Partners, filed a complaint in the United States District Court of the Southern District of Texas, Houston Division, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned *John Rinker and Arthur H. Speier, on Behalf of Themselves and All Others Similarly Situated v. Duncan Energy Partners L.P., DEP Holdings, LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard S. Snell and Enterprise Products Partners L.P.* The Rinker/Speier complaint alleges, among other things, that Duncan Energy Partners, DEP GP and the named directors of DEP GP breached express and implied contractual duties in connection with the Duncan Merger, that all defendants aided and abetted in these alleged breaches, and that we and Duncan Energy Partners violated Section 14(a) and Section 20(a) of the Exchange Act. On October 17, 2011, the plaintiffs filed a Stipulation of Dismissal Without Prejudice, which was signed by the court on October 19, 2011.

Environmental-Related Matters

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

In March 2007, a segment of our Conway North pipeline, which is a component of our Mid-America Pipeline System ("MAPL"), was struck by a third party in Nebraska causing a release of 1,725 barrels of natural gasoline in Nebraska. EPO and its subsidiary that owns MAPL each received letters dated June 4, 2009, from the U.S. Department of Justice ("DOJ") informing them that the DOJ desired to discuss violations of the federal Clean Water Act related to the release and potential settlement of the alleged violations. We have begun discussions with the DOJ and believe that the eventual resolution of this matter will result in a penalty exceeding $0.1 million.

In April 2010, a segment of our Conway North pipeline located in Kansas ruptured as a result of historical damage to the pipeline, which resulted in the release of 1,669 barrels of natural gasoline. We have begun discussions with the DOJ and believe that the eventual resolution of this matter will result in a penalty exceeding $0.1 million.

In September 2011, we received two compliance orders from the Colorado Department of Public Health and Environment. These compliance orders resolve alleged violations of air pollution regulations and related permit requirements in 2008 and 2009 at our facilities located in Colorado. We believe that the eventual resolution of these Colorado matters will result in penalties and other costs exceeding $0.5 million.

Redelivery Commitments

We store natural gas, NGLs, certain petrochemical products and crude oil owned by third parties under various agreements. Under the terms of these agreements, we are generally required to redeliver volumes to the owner on demand. At September 30, 2011, we had approximately 28.2 MMBbls of NGL and petrochemical products, 4.6 MMBbls of crude oil and 15.0 trillion British thermal units of natural gas in our custody that were owned by third parties. We maintain insurance coverage related to such volumes that we believe is consistent with our exposure. See Note 16 for information regarding insurance matters.

Regulatory Matters

Responding to scientific reports regarding threats posed by global warming, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases. In addition, some states, including states in which our facilities or operations are located such as California and New Mexico, have individually or in regional cooperation, imposed restrictions on greenhouse gas emissions under various policies and approaches, including establishing a cap on emissions, requiring efficiency measures, or providing incentives for pollution reduction, use of renewable energy, or use of fuels with lower carbon content.

The U.S. Environmental Protection Agency ("EPA") has taken action under the federal Clean Air Act ("CAA") to regulate greenhouse gas emissions. In November 2010, the EPA finalized rules expanding its Mandatory Greenhouse Gas Reporting Rule, originally promulgated in October 2009, to be applicable to the oil and natural gas industry, including certain onshore oil and natural gas production activities, which may affect certain of our existing or future operations and require the inventory and reporting of emissions. In addition, the EPA has taken the position that existing CAA provisions require an assessment of greenhouse gas emissions within the permitting process for certain large new or modified stationary sources under the EPA's Prevention of Significant Deterioration and Title V permit programs beginning in 2011. Facilities triggering permit requirements may be required to reduce greenhouse gas emissions consistent with "best available control technology" standards if deemed to be cost-effective.

These or other federal, regional and state measures could increase the operating and compliance costs of our pipelines, natural gas processing plants, fractionation plants and other facilities, and could by affecting the price of, or reducing the demand for, fossil fuels or providing competitive advantages to competing fuels and energy sources, adversely affect market demand or pricing for our products or products served by our midstream infrastructure. In addition, there have been several court cases implicating greenhouse gas emissions and climate change issues that could establish precedent that may indirectly affect our business, customers or the energy sector generally.

Any of these climate change legislative or judicial initiatives or developments could have a material impact on our financial statements; however, we are unable to provide a range of estimated future costs due to the extreme uncertainty of such matters. There is considerable public and private debate over global warming and the environmental effects of greenhouse gas emissions.

Contractual Obligations

Scheduled Maturities of Long-Term Debt

Since January 1, 2011, we (i) issued Senior Notes AA and BB in January 2011, (ii) repaid our Senior Notes B in February 2011, (iii) issued Senior Notes CC and DD in August 2011, (iv) entered into a new $3.5 Billion Multi-Year Revolving Credit Facility in September 2011 and concurrently terminated our $1.75 Billion Multi-Year Revolving Credit Facility and (v) repaid and terminated Duncan Energy Partners' debt obligations in September 2011 in connection with the Duncan Merger. See Note 10 for additional information regarding our consolidated debt obligations.

Operating Lease Obligations

Lease and rental expense included in costs and expenses was $21.2 million and $18.3 million during the three months ended September 30, 2011 and 2010, respectively. For the nine months ended September 30, 2011 and 2010, lease and rental expense was $63.2 million and $50.6 million, respectively. With the exception of $36.3 million in new lease commitments entered into by our truck transport business, there have been no material changes in our operating lease commitments since those reported in our 2010 Form 10-K.

Purchase Obligations

Full commercial operations on the Haynesville Extension of our Acadian Gas System commenced November 1, 2011. As part of our natural gas marketing activities, we entered into long-term natural gas purchase agreements that were contingent upon completion of the Haynesville Extension. Our firm purchase commitments under these contracts range from 90 days to 10 years. The following table presents our estimated firm purchase commitments (in terms of volumes and costs) under these agreements for the periods indicated (dollars in millions):

	Payment or Settlement due by Period						
Contractual Obligations	**Total**	**Remainder of 2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 3,416.7	$ 131.9	$ 593.6	$ 587.3	$ 572.2	$ 496.8	$ 1,034.9
Underlying major volume commitments:							
Natural gas (in BBtus) (1)	1,006,775	38,887	175,113	173,375	168,800	146,000	304,600

(1) Volume is measured in billion British thermal units ("BBtus").

These estimated payment obligations are based on natural gas prices in effect at September 30, 2011 applied to all future purchase volume commitments. Actual future payment obligations may vary depending on prices at the time of purchase. Apart from the Haynesville Extension contracts, there have been no other material changes in our consolidated purchase obligations since those reported in our 2010 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 October 31, 2011, our contingent claims against such parties were approximately $39.5 million and claims against us were approximately $23.8 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated at this time; however, in our opinion, the likelihood of a material impact on our consolidated financial statements from such disputes is remote. Accordingly, accruals for loss contingencies related to these matters have not been reflected in our consolidated financial statements.

Centennial Guarantees

We have certain guarantee obligations in connection with our ownership interest in Centennial, which owns a refined products pipeline system that extends from the Texas Gulf Coast to central Illinois. We guaranteed one-half of Centennial's debt obligations, which obligates us to an estimated payment of $52.1 million in the event of a default by Centennial. As of September 30, 2011, we have a recorded liability of $7.3 million representing the estimated fair value of our share of the Centennial debt guaranty.

In lieu of Centennial procuring insurance to satisfy third-party claims arising from a catastrophic event, we and Centennial's other joint venture partner have entered a limited cash call agreement. We are obligated to contribute up to a maximum of $50.0 million (in proportion to our 50% ownership interest in Centennial) in the event of a catastrophic event. At September 30, 2011, we have a recorded liability of $3.2 million representing the estimated fair value of our cash call guaranty. Our cash contributions to Centennial under the agreement may be covered by our other insurance policies depending on the nature of the catastrophic event.

Note 16. Significant Risks and Uncertainties

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 a timing difference between amounts we are required to pay in connection with a loss and amounts we receive from insurance as reimbursement. Any event that materially interrupts the revenues generated by our consolidated operations, or other losses that require us to make material expenditures not covered by insurance, could reduce our ability to pay distributions to our partners and, accordingly, adversely affect the market price of our common units.

From a financial accounting perspective, we expense losses up to our deductible amount, which can range from $5.0 million to $75.0 million depending on the nature of the loss (windstorm or non-windstorm) and the assets involved (onshore or offshore). With respect to property damage insurance claims in excess of our deductible, we record a claim receivable from our insurers for our actual costs to repair the asset (or the carrying value of damaged assets we elect not to repair) when the recovery of such amounts is probable. To the extent that any of our property damage claims are later judged not recoverable, such amounts are expensed. If property damage insurance proceeds exceed our claim receivable, such excess amount is recognized as income (a gain) when either the non-refundable cash is received or we have a binding settlement agreement with a carrier that clearly states that the payment will be made.

We received cash proceeds of $1.5 million related to property damage claims during the three and nine months ended September 30, 2011. During the three and nine months ended September 30, 2010 we received cash proceeds of $107.5 million and $148.5 million, respectively, related to property damage claims. For the three and nine months ended September 30, 2010 operating income and gross operating margin include $3.1 million and $21.3 million, respectively, of related gains.

With respect to business interruption insurance claims, we recognize income only when we receive non-refundable cash proceeds from insurers. For the three and nine months ended September 30, 2011, we recognized $3.7 million of such gains, which are a component of operating income and gross operating margin. During the three and nine months ended September 30, 2010, we recognized $5.1 million and $6.2 million, respectively, of such gains.

February 2011 West Storage Incident. On February 8, 2011, we experienced an NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. West Storage consists of ten underground salt dome storage caverns with a storage capacity of approximately 15 MMBbls. Through the reconfiguration of product receipt and delivery capabilities and other measures, we have returned our Mont Belvieu plants and related assets to close to the same capabilities as we had prior to the incident; however, our West Storage location and associated underground storage wells remain partially inoperative at this time. Remaining repairs to this location are underway and are expected to be completed in stages by early 2012. Our insurance deductible for such property damage events was $5.0 million, which expense was recognized in the first quarter of 2011. Based on current information, we estimate that the total capital cost related to this incident will approximate $200 million. At September 30, 2011, we had $58.1 million of estimated property damage insurance claims outstanding, including $52.1 million associated with the fire at West Storage.

Note 17. Supplemental Cash Flow Information

The following table provides information regarding the net effect of changes in our operating assets and liabilities for the periods presented:

	For the Nine Months Ended September 30,	
	2011	**2010**
Decrease (increase) in:		
Accounts receivable – trade	$ (218.3)	$ 78.9
Accounts receivable – related parties	(1.0)	8.5
Inventories	(21.1)	(520.9)
Prepaid and other current assets	(35.0)	(68.1)
Other assets	(48.6)	11.5
Increase (decrease) in:		
Accounts payable – trade	114.1	123.3
Accounts payable – related parties	79.0	28.5
Accrued product payables	285.6	(53.9)
Accrued interest	(68.7)	(49.7)
Other current liabilities	(40.1)	35.5
Other liabilities	15.7	(5.4)
Net effect of changes in operating accounts	$ 61.6	$ (411.8)

We incurred liabilities for construction in progress that had not been paid at September 30, 2011 and December 31, 2010 of $267.8 million and $201.6 million, respectively. Such amounts are not included under the caption “Capital expenditures” on the Unaudited Condensed Statements of Consolidated Cash Flows.

Third parties may be obligated to reimburse us for all or a portion of expenditures on certain of our capital projects. The majority of such arrangements are associated with projects related to pipeline construction and producer well tie-ins. These amounts are included under the caption “Contributions in aid of construction costs” on the Unaudited Condensed Statements of Consolidated Cash Flows.

Proceeds from asset sales and related transactions increased $350.9 million period-to-period, primarily from the sale of 8.56 million Energy Transfer Equity common units and certain non-strategic marine assets, NGL fractionation facilities and a natural gas gathering pipeline system during 2011.

See Note 11 for information regarding cash amounts attributable to noncontrolling interests.

See Note 16 for information regarding cash proceeds from insurance claims.

Note 18. Condensed Consolidating Financial Information

EPO conducts all of our business. Currently, we have no independent operations and no material assets outside those of EPO and its subsidiaries.

EPO has issued publicly traded debt securities (see Note 10). 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, then Enterprise Products Partners L.P. would be responsible for full 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.

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
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
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	$ 91.8	$ 44.0	$ (28.1)	$ 107.7	$ --	$ --	$ 107.7
Accounts receivable – trade, net	1,643.5	2,367.3	(2.4)	4,008.4	--	--	4,008.4
Accounts receivable – related parties	110.7	2,001.1	(2,074.0)	37.8	(0.3)	--	37.5
Inventories	1,165.5	226.6	(2.8)	1,389.3	--	--	1,389.3
Assets held for sale	--	455.1	--	455.1	--	--	455.1
Prepaid and other current assets	241.3	129.1	(20.1)	350.3	0.1	--	350.4
Total current assets	3,252.8	5,223.2	(2,127.4)	6,348.6	(0.2)	--	6,348.4
Property, plant and equipment, net	1,512.5	19,885.3	(9.7)	21,388.1	--	--	21,388.1
Investments in unconsolidated affiliates	26,365.9	8,053.9	(32,511.3)	1,908.5	11,439.0	(11,439.0)	1,908.5
Intangible assets, net	145.7	1,554.7	(13.8)	1,686.6	--	--	1,686.6
Goodwill	458.9	1,633.4	--	2,092.3	--	--	2,092.3
Other assets	272.6	154.5	(126.6)	300.5	--	--	300.5
Total assets	$ 32,008.4	$ 36,505.0	$ (34,788.8)	$ 33,724.6	$ 11,438.8	$ (11,439.0)	$ 33,724.4
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 990.5	$ 9.5	$ --	$ 1,000.0	$ --	$ --	$ 1,000.0
Accounts payable – trade	240.4	608.4	(28.1)	820.7	0.1	--	820.8
Accounts payable – related parties	2,218.0	187.7	(2,193.5)	212.2	--	--	212.2
Accrued product payables	2,279.0	2,442.5	(6.0)	4,715.5	--	--	4,715.5
Accrued interest	183.0	1.0	(0.1)	183.9	--	--	183.9
Liabilities related to assets held for sale	--	72.2	--	72.2	--	--	72.2
Other current liabilities	318.0	338.0	(16.9)	639.1	--	0.2	639.3
Total current liabilities	6,228.9	3,659.3	(2,244.6)	7,643.6	0.1	0.2	7,643.9
Long-term debt	14,063.9	53.7	(8.9)	14,108.7	--	--	14,108.7
Deferred tax liabilities	4.6	80.6	(0.5)	84.7	--	(0.9)	83.8
Other long-term liabilities	134.4	202.1	--	336.5	--	--	336.5
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	11,576.6	27,974.9	(28,129.0)	11,422.5	11,438.7	(11,422.5)	11,438.7
Noncontrolling interests	--	4,534.4	(4,405.8)	128.6	--	(15.8)	112.8
Total equity	11,576.6	32,509.3	(32,534.8)	11,551.1	11,438.7	(11,438.3)	11,551.5
Total liabilities and equity	$ 32,008.4	$ 36,505.0	$ (34,788.8)	$ 33,724.6	$ 11,438.8	$ (11,439.0)	$ 33,724.4

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
December 31, 2010

	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	$ 97.1	$ 70.0	$ (2.9)	$ 164.2	$ --	$ --	$ 164.2
Accounts receivable – trade, net	1,684.1	2,127.9	(11.9)	3,800.1	--	--	3,800.1
Accounts receivable – related parties	206.3	927.6	(1,095.8)	38.1	(1.3)	--	36.8
Inventories	825.3	310.0	(1.3)	1,134.0	--	--	1,134.0
Prepaid and other current assets	205.4	176.2	(9.6)	372.0	--	--	372.0
Total current assets	3,018.2	3,611.7	(1,121.5)	5,508.4	(1.3)	--	5,507.1
Property, plant and equipment, net	1,461.0	17,881.9	(10.0)	19,332.9	--	--	19,332.9
Investments in unconsolidated affiliates	22,640.3	6,254.0	(26,601.2)	2,293.1	11,375.5	(11,375.5)	2,293.1
Intangible assets, net	155.5	1,700.8	(14.6)	1,841.7	--	--	1,841.7
Goodwill	469.1	1,638.6	--	2,107.7	--	--	2,107.7
Other assets	296.4	126.7	(144.8)	278.3	--	--	278.3
Total assets	$ 28,040.5	$ 31,213.7	$ (27,892.1)	$ 31,362.1	$ 11,374.2	$ (11,375.5)	$ 31,360.8
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ --	$ 282.3	$ --	$ 282.3	$ --	$ --	$ 282.3
Accounts payable – trade	138.1	406.8	(2.9)	542.0	--	--	542.0
Accounts payable – related parties	1,159.0	204.3	(1,230.2)	133.1	--	--	133.1
Accrued product payables	2,057.2	2,124.8	(17.2)	4,164.8	--	--	4,164.8
Accrued interest	251.3	1.8	(0.2)	252.9	--	--	252.9
Other current liabilities	217.2	294.7	(6.9)	505.0	--	0.1	505.1
Total current liabilities	3,822.8	3,314.7	(1,257.4)	5,880.1	--	0.1	5,880.2
Long-term debt	12,663.7	626.4	(8.9)	13,281.2	--	--	13,281.2
Deferred tax liabilities	5.1	73.8	(0.1)	78.8	--	(0.8)	78.0
Other long-term liabilities	42.9	177.7	--	220.6	--	--	220.6
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	11,506.0	23,176.8	(23,321.2)	11,361.6	11,374.2	(11,361.6)	11,374.2
Noncontrolling interests	--	3,844.3	(3,304.5)	539.8	--	(13.2)	526.6
Total equity	11,506.0	27,021.1	(26,625.7)	11,901.4	11,374.2	(11,374.8)	11,900.8
Total liabilities and equity	$ 28,040.5	$ 31,213.7	$ (27,892.1)	$ 31,362.1	$ 11,374.2	$ (11,375.5)	$ 31,360.8

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 provision for 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.
Unaudited Condensed Consolidating Statement of Operations
Three Months Ended September 30, 2010

	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)	Holdings and EPGP	Eliminations and Adjustments	Consolidated Total
Revenues	$ 6,068.5	$ 4,940.9	$ (2,941.6)	$ 8,067.8	$ --	$ --	$ --	$ 8,067.8
Costs and expenses:								
Operating costs and expenses	5,977.6	4,425.0	(2,942.5)	7,460.1	--	--	--	7,460.1
General and administrative costs	8.1	47.6	--	55.7	0.3	14.1	--	70.1
Total costs and expenses	5,985.7	4,472.6	(2,942.5)	7,515.8	0.3	14.1	--	7,530.2
Equity in income of unconsolidated affiliates	463.1	21.4	(467.0)	17.5	372.2	128.1	(512.2)	5.6
Operating income	545.9	489.7	(466.1)	569.5	371.9	114.0	(512.2)	543.2
Other income (expense):								
Interest expense	(176.2)	(6.4)	2.9	(179.7)	--	(12.3)	--	(192.0)
Other, net	3.1	1.1	(2.9)	1.3	--	--	--	1.3
Total other expense, net	(173.1)	(5.3)	--	(178.4)	--	(12.3)	--	(190.7)
Income before provision for income taxes	372.8	484.4	(466.1)	391.1	371.9	101.7	(512.2)	352.5
Provision for income taxes	(1.6)	(3.2)	--	(4.8)	--	--	(0.1)	(4.9)
Net income	371.2	481.2	(466.1)	386.3	371.9	101.7	(512.3)	347.6
Net loss (income) attributable to noncontrolling interests	--	10.7	(24.9)	(14.2)	--	--	(296.4)	(310.6)
Net income attributable to entity	$ 371.2	$ 491.9	$ (491.0)	$ 372.1	$ 371.9	$ 101.7	$ (808.7)	$ 37.0

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 provision for 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.
Unaudited Condensed Consolidating Statement of Operations
Nine Months Ended September 30, 2010

	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)	Holdings and EPGP	Eliminations and Adjustments	Consolidated Total
Revenues	$ 18,684.4	$ 14,341.2	$ (8,869.9)	$ 24,155.7	$ --	$ --	$ --	$ 24,155.7
Costs and expenses:								
Operating costs and expenses	18,374.1	12,903.1	(8,871.0)	22,406.2	--	--	--	22,406.2
General and administrative costs	11.0	116.0	--	127.0	4.5	19.4	--	150.9
Total costs and expenses	18,385.1	13,019.1	(8,871.0)	22,533.2	4.5	19.4	--	22,557.1
Equity in income of unconsolidated affiliates	1,296.1	117.3	(1,363.2)	50.2	1,111.4	400.2	(1,518.6)	43.2
Operating income	1,595.4	1,439.4	(1,362.1)	1,672.7	1,106.9	380.8	(1,518.6)	1,641.8
Other income (expense):								
Interest expense	(484.1)	(20.8)	8.0	(496.9)	--	(32.2)	--	(529.1)
Other, net	8.5	1.3	(8.0)	1.8	--	--	--	1.8
Total other expense, net	(475.6)	(19.5)	--	(495.1)	--	(32.2)	--	(527.3)
Income before provision for income taxes	1,119.8	1,419.9	(1,362.1)	1,177.6	1,106.9	348.6	(1,518.6)	1,114.5
Provision for income taxes	(9.9)	(10.1)	--	(20.0)	--	--	(0.1)	(20.1)
Net income	1,109.9	1,409.8	(1,362.1)	1,157.6	1,106.9	348.6	(1,518.7)	1,094.4
Net loss (income) attributable to noncontrolling interests	--	17.3	(63.9)	(46.6)	--	--	(886.8)	(933.4)
Net income attributable to entity	$ 1,109.9	$ 1,427.1	$ (1,426.0)	$ 1,111.0	$ 1,106.9	$ 348.6	$ (2,405.5)	$ 161.0

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)
Other investing activities	(2,004.0)	423.8	2,021.5	441.3	(71.2)	71.2	441.3
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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
Nine Months Ended September 30, 2010

	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)	Holdings and EPGP	Eliminations and Adjustments	Consolidated Total
Operating activities:								
Net income	$ 1,109.9	$ 1,409.8	$ (1,362.1)	$ 1,157.6	$ 1,106.9	$ 348.6	$ (1,518.7)	$ 1,094.4
Reconciliation of net income to net cash flows provided by operating activities:								
Depreciation, amortization and accretion	84.2	621.0	(1.0)	704.2	--	4.9	--	709.1
Equity in income of unconsolidated affiliates	(1,296.1)	(117.3)	1,363.2	(50.2)	(1,111.4)	(400.2)	1,518.6	(43.2)
Distributions received from unconsolidated affiliates	138.3	121.9	(177.9)	82.3	1,273.5	482.9	(1,692.7)	146.0
Net effect of changes in operating accounts and other operating activities	587.1	(354.6)	(705.8)	(473.3)	(0.9)	11.7	--	(462.5)
Net cash flows provided by operating activities	623.4	1,680.8	(883.6)	1,420.6	1,268.1	447.9	(1,692.8)	1,443.8
Investing activities:								
Capital expenditures, net of contributions in aid of construction costs	24.3	(1,415.5)	--	(1,391.2)	--	--	--	(1,391.2)
Cash used for business combinations	(2.2)	(1,230.8)	--	(1,233.0)	--	--	--	(1,233.0)
Other investing activities	(1,583.6)	129.9	1,576.4	122.7	(1,056.7)	(54.5)	1,111.2	122.7
Cash used in investing activities	(1,561.5)	(2,516.4)	1,576.4	(2,501.5)	(1,056.7)	(54.5)	1,111.2	(2,501.5)
Financing activities:								
Borrowings under debt agreements	3,965.7	138.1	--	4,103.8	--	66.5	--	4,170.3
Repayments of debt	(2,686.8)	(67.0)	--	(2,753.8)	--	(62.8)	--	(2,816.6)
Cash distributions paid to partners	(1,273.5)	(963.1)	963.1	(1,273.5)	(1,263.1)	(418.9)	2,727.9	(227.6)
Cash distributions paid to noncontrolling interests	--	(99.1)	44.9	(54.2)	--	--	(1,044.8)	(1,099.0)
Cash contributions from noncontrolling interests	--	356.7	(353.6)	3.1	--	--	1,031.3	1,034.4
Net cash proceeds from issuance of common units	--	--	--	--	1,054.9	--	(1,054.9)	--
Cash contributions from owners	1,056.7	1,358.3	(1,358.3)	1,056.7	--	21.3	(1,078.0)	--
Other financing activities	(138.4)	125.0	--	(13.4)	(3.1)	--	--	(16.5)
Cash provided by (used in) financing activities	923.7	848.9	(703.9)	1,068.7	(211.3)	(393.9)	581.5	1,045.0
Effect of exchange rate changes on cash	--	0.3	--	0.3	--	--	--	0.3
Net change in cash and cash equivalents	(14.4)	13.3	(11.1)	(12.2)	0.1	(0.5)	(0.1)	(12.7)
Cash and cash equivalents, January 1	14.4	46.3	(6.2)	54.5	--	0.7	0.1	55.3
Cash and cash equivalents, September 30	$ --	$ 59.9	$ (17.3)	$ 42.6	$ 0.1	$ 0.2	$ --	$ 42.9

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

For the three and nine months ended September 30, 2011 and 2010.

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. The following information and such unaudited condensed consolidated financial statements should also be read in conjunction with the audited 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, 2010, as filed on March 1, 2011 (the "2010 Form 10-K"). Our financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States.

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 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 Delaware limited liability company.

On September 3, 2010, Enterprise GP Holdings L.P. ("Holdings"), Enterprise, Enterprise GP, Enterprise Products GP, LLC ("EPGP," the former general partner of Enterprise) and Enterprise ETE LLC ("Holdings MergerCo," a Delaware limited liability company and a wholly owned subsidiary of Enterprise) entered into a merger agreement (the "Holdings Merger Agreement"). On November 22, 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with and into Holdings MergerCo and related transactions were completed, with Holdings MergerCo surviving such merger (collectively, we refer to these transactions as the "Holdings Merger"). Enterprise's membership interests in Holdings MergerCo were subsequently contributed to EPO. For additional information regarding the Holdings Merger, see "Basis for Financial Statement Presentation" within this Item 2.

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 and one of three managers of Dan Duncan LLC; (ii) Dr. Ralph S. Cunningham, who is also a director and the Chairman of Enterprise GP and one of three managers of Dan Duncan LLC; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP and one of three managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company 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 serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President and Chief Executive Officer ("CEO") of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also directors of EPCO.

On April 28, 2011, we, our general partner, EPD MergerCo LLC ("Duncan MergerCo," a Delaware limited liability company and 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"). On September 7, 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 "Significant Recent Developments" included under this Item 2 for additional information regarding the Duncan Merger.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP") and Regency Energy Partners LP. We own noncontrolling limited partner interests in Energy Transfer Equity, which we account for using the equity method of accounting. Energy Transfer Equity electronically files reports with the U.S. Securities and Exchange Commission ("SEC"), including annual reports on Form 10-K and quarterly reports on Form 10-Q. The SEC maintains an Internet website at www.sec.gov that contains periodic reports and other information regarding this registrant.

References to "Employee Partnerships" mean EPE Unit L.P., EPE Unit II, L.P., EPE Unit III, L.P., Enterprise Unit L.P. and EPCO Unit L.P., collectively, all of which were privately held affiliates of EPCO. The Employee Partnerships were liquidated in August 2010. See "Results of Operations" included under this Item 2 for additional information.

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

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

Cautionary Note Regarding Forward-Looking Statements

This discussion contains various forward-looking statements and information based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that the 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 Item 1A "Risk Factors" included in our 2010 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 certain petrochemicals. Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. Our assets include approximately 50,000 miles of onshore and offshore pipelines; 192 MMBbls of storage capacity for NGLs, refined products and crude oil; and 27 Bcf of total working natural gas storage capacity.

Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminaling; crude oil and refined products transportation, storage, and terminaling; offshore production platforms; petrochemical transportation and services; and a marine transportation business that operates primarily on the United States inland and Intracoastal Waterway systems and in the Gulf of Mexico. We have six reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; (v) Petrochemical & Refined Products Services; and (vi) Other Investments.

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

Basis of Financial Statement Presentation

In accordance with rules and regulations of the SEC and various other accounting standard-setting organizations, our general purpose financial statements reflect the consolidation of financial information of businesses that we control. Our general purpose consolidated financial statements present those investments over which we do not have control as unconsolidated affiliates (e.g., our equity method investment in Energy Transfer Equity). Noncontrolling interest reflects third-party and related party ownership of our consolidated subsidiaries.

Prior to the Holdings Merger, Enterprise was a consolidated subsidiary of Holdings, which was Enterprise's parent. Upon completion of the Holdings Merger, Holdings merged with and into a wholly owned subsidiary of Enterprise. The Holdings Merger resulted in Holdings being considered the surviving consolidated entity for accounting purposes, while Enterprise Products Partners L.P. is the surviving consolidated entity for legal and reporting purposes. For accounting purposes, Holdings is deemed the acquirer of the noncontrolling interest in Enterprise that were previously recognized in Holdings' consolidated financial statements (i.e., the acquisition of Enterprise's limited partner interests that were owned by parties other than Holdings).

As a result of the Holdings Merger, Enterprise's consolidated financial and operating results prior to November 22, 2010 have been presented as if Enterprise were Holdings from an accounting perspective (i.e., the financial statements of Holdings became the historical financial statements of Enterprise). While it was a publicly traded partnership, Holdings (NYSE, ticker symbol "EPE") electronically filed its annual and quarterly consolidated financial statements with the SEC. You can access this information at www.sec.gov.

The primary differences between Holdings' and Enterprise's consolidated results of operations were (i) general and administrative costs incurred by Holdings and EPGP (our former general partner); (ii) equity in income of Holdings' noncontrolling ownership interests in Energy Transfer Equity; and (iii) interest expense associated with Holdings' debt. In addition, for periods prior to November 22, 2010, the net assets, income, cash distributions and contributions and other amounts attributable to Enterprise's limited partner interests that were owned by third parties and related parties other than Holdings are presented as a component of noncontrolling interests. See Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding our noncontrolling interests.

Historical limited partner units outstanding and earnings per unit amounts presented in our financial statements have been retroactively presented in connection with the 1.5 to one unit-for-unit exchange that occurred under the Holdings Merger. See Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding earnings per unit.

Significant Recent Developments

The following information highlights significant developments since January 1, 2011 through the date of this filing (November 9, 2011), including (i) information relevant to an understanding of our financial condition, changes in financial condition or results of operations, and (ii) certain unusual or infrequent events or transactions and known trends or uncertainties that have had or that we reasonably expect may have a material impact on our revenues or income from continuing operations.

Enterprise to Expand Its Natural Gas Pipeline and Processing Infrastructure in the Eagle Ford Shale

On November 1, 2011, we announced several new construction projects that will extend and expand our natural gas and NGL infrastructure in South Texas to accommodate expected production growth from the Eagle Ford Shale. As a result of additional demand from our Eagle Ford Shale producing customers, along with the execution of new gathering and processing agreements, we plan to expand natural gas processing capacity at our Yoakum facility (which is currently under construction) by an additional 300 MMcf/d. Once the expansion is completed, our Yoakum facility will have total gas processing capacity of 900 MMcf/d. We also plan to increase the size of the NGL takeaway pipelines originating at the Yoakum plant to handle the expected increase in NGL production. We expect the Yoakum facility to commence operations during the first quarter of 2013. The new Yoakum plant will complement our seven existing natural gas processing plants in South Texas, which currently have the capacity to process approximately 1.5 Bcf/d.

In addition to the Yoakum expansion, we are constructing 62 miles of natural gas pipeline loops and increasing compression to gather and transport an additional 300 MMcf/d of rich Eagle Ford Shale gas. These pipeline expansion projects are also expected to begin service in the first quarter of 2013.

Start of Service on Acadian Haynesville Extension

Full commercial operations on the Haynesville Extension of our Acadian Gas System commenced November 1, 2011. As a result of completing the Haynesville Extension project, we have provided producers in Louisiana's Haynesville and Bossier Shale plays with access to 1.8 Bcf/d of incremental natural gas takeaway capacity. As an extension of our Acadian Gas System, the Haynesville Extension offers producers access to more than 150 end-user customer service locations along the Mississippi River industrial corridor between Baton Rouge and New Orleans, as well as the Henry Hub. The Haynesville Extension features interconnects with twelve interstate pipeline systems and is the only southerly option that avoids potential natural gas supply bottlenecks at the Perryville Hub and offers producers flow assurance and market choice to assist in maximizing the value of their natural gas.

Enterprise to Sell Mississippi Natural Gas Storage Facilities

In October 2011, Enterprise announced that it executed definitive agreements to sell all of its ownership interests in Crystal Holding L.L.C. ("Crystal") to Boardwalk HP Storage Company, LLC ("Boardwalk") for $550 million in cash. Crystal owns two underground salt dome natural gas storage facilities and related pipelines located near Petal and Hattiesburg, Mississippi. The facilities have approximately 29 Bcf of total storage capacity and are owned by Petal Gas Storage, L.L.C. ("Petal") and Hattiesburg Gas Storage Company ("Hattiesburg"). Proceeds from this sale will be used for general partnership purposes, including the funding of capital expenditures. This transaction is subject to customary regulatory approvals and is expected to close during the fourth quarter of 2011.

The Petal and Hattiesburg operations are a component of our Onshore Natural Gas Pipelines & Services business segment. The assets and liabilities of Petal and Hattiesburg were classified as held for sale and presented separately in the current assets and current liabilities sections, respectively, of our Unaudited Condensed Consolidated Balance Sheet at September 30, 2011. See Note 6 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding this presentation.

Enterprise to Develop Long-Haul Ethane Pipeline

In October 2011, Enterprise announced plans to design, construct and operate a long-haul pipeline to transport ethane from the Marcellus and Utica shale regions in Pennsylvania, West Virginia and Ohio to the U.S. Gulf Coast. The approximately 1,230-mile pipeline would have an initial capacity of 125 MBPD, which could be expanded to meet increased shipper demand. The pipeline would deliver ethane to our NGL storage complex in Mont Belvieu, Texas. Ethane production from the Marcellus and Utica shales would ultimately have direct or indirect access to every ethylene plant in the U.S. through connections in Mont Belvieu. The pipeline would be expected to begin commercial operations in the first quarter of 2014.

The project would utilize a combination of new and existing infrastructure. The northern portion of the proposed system involves construction of a pipeline that would originate in Washington County, Pennsylvania and extend west, then southwest, following existing pipeline corridors in order to minimize the footprint of the project. At Cape Girardeau, Missouri the pipeline would interconnect with our existing 16-inch diameter TE Products Pipeline, which would be reversed to accommodate southbound delivery of ethane to the U.S. Gulf Coast. At the terminus of our Products Pipeline System in Beaumont, Texas, we would construct a 55-mile pipeline to connect to our Mont Belvieu facility.

In November 2011, we announced the execution of a long-term take-or-pay contract with a shipper. The volume commitment under this anchor contract represents 75 MBPD (over a five-year ramp up period) of the pipeline's initial capacity of 125 MBPD. The open commitment period for other interested shippers remains open until November 10, 2011.

Enterprise and Enbridge to Develop Crude Oil Pipeline

In September 2011, Enterprise and Enbridge Inc. ("Enbridge") announced plans to design, construct and operate a pipeline (the "Wrangler Pipeline") to transport crude oil from the oversupplied hub at Cushing, Oklahoma to the Texas Gulf Coast refining complex. Initially, the Wrangler Pipeline will have the capacity to transport up to 800 MBPD of crude oil and accommodate the medium-to-light crude oil currently stranded at Cushing, which is priced at a substantial discount to the oil imports that account for most of the supply being used by Gulf Coast refiners. In anticipation of future increases in crude oil volumes delivered to the Cushing area, the joint venture partners will design the pipeline to be expanded.

The proposed 36-inch diameter pipeline will originate at the existing Enbridge Cushing Terminal and extend approximately 500 miles southward, closely following existing pipeline corridors, to our ECHO crude oil storage terminal (which is currently under construction) in southeast Harris County, Texas, providing access to refineries in Texas City, Pasadena/Deer Park, Baytown and along the Houston Ship Channel. Installation of new storage tanks at the ECHO facility will be included in the proposed joint venture. The project will also include a new 85-mile pipeline extending from the ECHO facility to the Beaumont/Port Arthur refining center.

Subject to the required regulatory approvals and sufficient long-term commitments from interested shippers, the pipeline is expected to be in service by mid-2013. Construction of the project is expected to be managed by Enbridge with Enterprise serving as operator.

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 rate of 1.01 Enterprise common units for each Duncan Energy Partners common unit. Enterprise issued 24,277,310 of its common units (net of 9 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 have historically consolidated Duncan Energy Partners for financial reporting purposes, the Duncan Merger did not change the basis of presentation of our historical financial statements. Furthermore, we will continue to consolidate Duncan Energy Partners for financial reporting purposes; however, Duncan Energy Partners will no longer include any noncontrolling interest due to former owners of its limited partner interests.

Enterprise to Jointly Develop New NGL Pipeline

In September 2011, Enterprise, Enbridge Energy Partners, L.P. and Anadarko Petroleum Corporation announced an agreement to design and construct a new NGL pipeline (the "Texas Express Pipeline") that will originate from Skellytown, Texas in Carson County and extend approximately 580 miles to NGL fractionation and storage facilities in Mont Belvieu, Texas. The Texas Express Pipeline will allow producers in West and Central Texas, the Rocky Mountains, Southern Oklahoma and the Mid-continent maximize the value of their natural gas production by providing additional takeaway capacity and enhanced access to the Gulf Coast NGL market. Initial capacity on the pipeline will be approximately 280 MBPD, which can be expanded to approximately 400 MBPD.

In addition, the joint venture will include two new NGL gathering systems. The first will connect the Texas Express Pipeline to natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and Western Oklahoma. The second NGL gathering system will connect the new pipeline to Central Texas, Barnett Shale gas processing plants. NGL volumes from the Rockies, Permian Basin and Mid-continent regions will be delivered to the Texas Express Pipeline utilizing Enterprise's existing Mid-America Pipeline assets between the Conway hub and Enterprise's Hobbs NGL fractionation facility in Gaines County, Texas. Enterprise will construct and serve as the operator of the pipeline, while Enbridge will build and operate the new NGL gathering systems. Subject to regulatory approvals, these pipeline and gathering systems are expected to begin service in the second quarter of 2013.

Enterprise to Build Sixth NGL Fractionator at Mont Belvieu, Texas Complex

In June 2011, we announced plans to construct a sixth NGL fractionator at our Mont Belvieu, Texas facility. The new fractionation facility will have a nameplate capacity of 75 MBPD and accommodate continued growth of liquids-rich natural gas production from the prolific Eagle Ford Shale basin in South Texas. All necessary approvals and permits have been obtained and we have started construction of the new facility, which is projected to begin service in late 2012.

In October 2011, commercial operations at our fifth NGL fractionator at Mont Belvieu commenced. This new fractionator increases total nameplate capacity at our Mont Belvieu facility to 380 MBPD. When the sixth fractionator (as noted above) is completed, we will have the capability to fractionate more than 450 MBPD of NGLs at our Mont Belvieu complex and our system-wide net fractionation capacity will increase to approximately 770 MBPD.

Enterprise to Extend Eagle Ford Shale Crude Oil Pipeline System

In May 2011, we announced plans to build an 80-mile extension of our 350 MBPD Eagle Ford Shale crude oil pipeline, which would allow us to serve growing production areas in the southwestern portion of the supply basin. The Phase II project, which is being designed with a capacity of 200 MBPD, would originate in Wilson County, Texas at the terminus of our previously announced 140-mile Phase I segment, and extend to a site near Gardendale, Texas in La Salle County, where a new central delivery point is planned for construction that will feature 500,000 barrels of storage. Phase I is projected to begin service by the second quarter of 2012, with Phase II set to commence operations in the first quarter of 2013. When completed, the approximately 220-mile crude oil pipeline system will provide Eagle Ford Shale producers with access to the Texas Gulf Coast refining complex through our integrated midstream network.

Expansion of Houston Ship Channel Import/Export Terminal

In March 2011, we announced the expansion of our import/export terminal on the Houston Ship Channel. The expansion project is expected to nearly double the fully refrigerated export loading capacity for propane and other NGLs at the facility to more than 10,000 barrels per hour, while enhancing its ability to load multiple vessels simultaneously. We expect to complete the expansion in the second half of 2012.

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Incident at Mont Belvieu Storage Facility

On February 8, 2011, we experienced an NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. West Storage consists of ten underground salt dome storage caverns with a storage capacity of approximately 15 MMBbls. Through the reconfiguration of product receipt and delivery capabilities and other measures, we have returned our Mont Belvieu plants and related assets to close to the same capabilities as we had prior to the incident; however, our West Storage location and associated underground storage wells remain partially inoperative at this time. Remaining repairs to this location are underway and are expected to be completed in stages by early 2012. Our insurance deductible for such property damage events was $5.0 million, which expense was recognized in our earnings for the first quarter of 2011.

Based on current information, we estimate that the total capital cost related to this incident will approximate $200 million. 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. See Note 16 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for information regarding insurance matters.

Results of Operations

Selected Price and Volumetric Data

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

	Natural Gas, $/MMBtu	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	Polymer Grade Propylene, $/pound	Refinery Grade Propylene, $/pound	Crude Oil, $/barrel
	(1)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(4)
2010									
1st Quarter	$ 5.30	$ 0.73	$ 1.24	$ 1.52	$ 1.64	$ 1.82	$ 0.63	$ 0.54	$ 78.72
2nd Quarter	$ 4.09	$ 0.55	$ 1.08	$ 1.47	$ 1.58	$ 1.81	$ 0.65	$ 0.44	$ 78.03
3rd Quarter	$ 4.38	$ 0.48	$ 1.07	$ 1.38	$ 1.43	$ 1.71	$ 0.58	$ 0.44	$ 76.20
4th Quarter	$ 3.80	$ 0.64	$ 1.26	$ 1.62	$ 1.68	$ 2.00	$ 0.59	$ 0.49	$ 85.17
2010 Averages	$ 4.39	$ 0.60	$ 1.16	$ 1.50	$ 1.58	$ 1.84	$ 0.61	$ 0.48	$ 79.53
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
2011 Averages	$ 4.21	$ 0.74	$ 1.47	$ 1.83	$ 1.99	$ 2.37	$ 0.81	$ 0.71	$ 95.48

(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").

The following table presents our significant average throughput, production and processing volumetric data for the periods presented. These statistics are reported on a net basis, taking into account our ownership interests in certain joint ventures, and reflect the periods in which we owned an interest in such operations. These statistics reflect volumes for newly constructed assets from the dates such assets were placed into service and for recently purchased assets from the date of acquisition.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
NGL Pipelines & Services, net:				
NGL transportation volumes (MBPD)	2,241	2,326	2,286	2,254
NGL fractionation volumes (MBPD)	554	476	557	471
Equity NGL production (MBPD)	114	122	117	123
Fee-based natural gas processing (MMcf/d)	3,813	2,722	3,733	2,795
Onshore Natural Gas Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	12,379	11,673	11,989	11,432
Onshore Crude Oil Pipelines & Services, net:				
Crude oil transportation volumes (MBPD)	725	684	678	678
Offshore Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	1,009	1,138	1,067	1,284
Crude oil transportation volumes (MBPD)	259	299	279	325
Platform natural gas processing (MMcf/d)	376	442	412	547
Platform crude oil processing (MBPD)	15	17	17	17
Petrochemical & Refined Products Services, net:				
Butane isomerization volumes (MBPD)	105	95	99	89
Propylene fractionation volumes (MBPD)	74	77	72	78
Octane additive and associated plant production volumes (MBPD)	18	19	17	14
Transportation volumes, primarily refined products and petrochemicals (MBPD)	797	854	767	871
Total, net:				
NGL, crude oil, refined products and petrochemical transportation volumes (MBPD)	4,022	4,163	4,010	4,128
Natural gas transportation volumes (BBtus/d)	13,388	12,811	13,056	12,716
Equivalent transportation volumes (MBPD) (1)	7,545	7,534	7,446	7,474

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

Comparison of Results of Operations

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
Revenues	$ 11,327.1	$ 8,067.8	$ 32,727.3	$ 24,155.7
Operating costs and expenses	10,604.6	7,460.1	30,675.0	22,406.2
General and administrative costs	50.0	70.1	138.3	150.9
Equity in income of unconsolidated affiliates	8.6	5.6	35.9	43.2
Operating income	681.1	543.2	1,949.9	1,641.8
Interest expense	189.0	192.0	561.1	529.1
Provision for income taxes	11.6	4.9	26.1	20.1
Net income	479.5	347.6	1,362.5	1,094.4
Net income attributable to noncontrolling interests	8.1	310.6	36.7	933.4
Net income attributable to partners	471.4	37.0	1,325.8	161.0

For information regarding amounts attributable to noncontrolling interests, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

The following table presents our gross operating margin by business segment and in total for the periods presented (dollars in millions):

	For the Three Months Ended September 30, 2011	For the Three Months Ended September 30, 2010	For the Nine Months Ended September 30, 2011	For the Nine Months Ended September 30, 2010
NGL Pipelines & Services	$ 547.6	$ 397.2	$ 1,549.7	$ 1,275.5
Onshore Natural Gas Pipelines & Services	156.0	154.1	476.3	391.3
Onshore Crude Oil Pipelines & Services	67.4	35.0	167.0	87.6
Offshore Pipelines & Services	53.9	68.3	168.6	232.2
Petrochemical & Refined Products Services	145.6	166.2	397.8	444.3
Other Investments	2.3	(11.9)	11.3	(7.0)
Total	$ 972.8	$ 808.9	$ 2,770.7	$ 2,423.9

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before provision for income taxes, see "Other Items – Non-GAAP Reconciliations" included within this Item 2. For additional information regarding our business segments, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

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

	For the Three Months Ended September 30, 2011	For the Three Months Ended September 30, 2010	For the Nine Months Ended September 30, 2011	For the Nine Months Ended September 30, 2010
NGL Pipelines & Services:				
Sales of NGLs	$ 4,163.9	$ 3,048.0	$ 12,052.5	$ 9,516.5
Sales of other petroleum and related products	1.0	0.6	2.3	1.8
Midstream services	253.6	185.9	657.4	541.8
Total	4,418.5	3,234.5	12,712.2	10,060.1
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	704.7	651.0	2,136.9	2,281.8
Midstream services	218.0	196.9	629.7	572.5
Total	922.7	847.9	2,766.6	2,854.3
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	3,929.8	2,701.4	11,535.9	7,672.1
Midstream services	27.3	24.5	73.4	69.7
Total	3,957.1	2,725.9	11,609.3	7,741.8
Offshore Pipelines & Services:				
Sales of natural gas	0.3	0.2	0.9	1.0
Sales of crude oil	1.3	2.3	7.1	6.3
Midstream services	58.5	68.3	180.2	239.4
Total	60.1	70.8	188.2	246.7
Petrochemical & Refined Products Services:				
Sales of other petroleum and related products	1,767.2	1,056.3	4,868.7	2,860.6
Midstream services	201.5	132.4	582.3	392.2
Total	1,968.7	1,188.7	5,451.0	3,252.8
Total consolidated revenues	$ 11,327.1	$ 8,067.8	$ 32,727.3	$ 24,155.7

Comparison of Three Months Ended September 30, 2011 with Three Months Ended September 30, 2010

Revenues for the third quarter of 2011 were $11.33 billion compared to $8.07 billion for the third quarter of 2010, a $3.26 billion quarter-to-quarter increase. Consolidated revenues from the sale of NGLs increased $1.12 billion quarter-to-quarter due to higher sales prices during the third quarter of 2011 compared to the third quarter of 2010. Natural gas and crude oil sales revenues increased $53.8 million and $1.23 billion quarter-to-quarter, respectively, primarily due to higher sales volumes. Consolidated revenues from the sale of petrochemicals and refined products increased $710.9 million quarter-to-quarter primarily due to higher propylene and refined products sales prices and higher refined products sales volumes during the third quarter of 2011 compared to the third quarter of 2010. Consolidated revenues from midstream services increased $61.3 million quarter-to-quarter due to the addition of revenues from businesses we acquired (e.g., the truck transport operations we acquired from EPCO effective September 30, 2010 and the high purity isobutylene operations we acquired in November 2010) and assets we constructed and placed into service (e.g., the start-up of our fourth NGL fractionator in Mont Belvieu in November 2010) since the third quarter of 2010. Revenues from the remainder of our midstream services increased $89.6 million quarter-to-quarter primarily due to increased natural gas production volumes from the Eagle Ford Shale supply basin, which resulted in higher natural gas processing and pipeline transportation revenues from our assets in South Texas during the third quarter of 2011 compared to the third quarter of 2010.

Operating costs and expenses were $10.60 billion for the third quarter of 2011 compared to $7.46 billion for the third quarter of 2010, a $3.14 billion quarter-to-quarter increase. The cost of sales of our marketing activities increased $2.48 billion quarter-to-quarter primarily due to higher energy commodity prices, with the exception of natural gas prices, and crude oil sales volumes. The operating costs and expenses of our natural gas processing plants increased $481.5 million quarter-to-quarter primarily due to higher natural gas processing volumes and NGL prices in the third quarter of 2011 relative to the third quarter of 2010. In general, higher NGL prices result in increased operating costs associated with percent-of-proceeds and margin-band types of natural gas processing contracts. Consolidated operating costs and expenses also increased $50.2 million quarter-to-quarter due to the addition of operating costs from businesses we acquired and assets we constructed and placed into service since the third quarter of 2010. Operating costs and expenses for the third quarter of 2010 were reduced by an insurance-related gain of $56.6 million recorded in connection with our disposition of a portion of an offshore natural gas pipeline and certain components of an offshore platform that we elected to retire rather than repair. Also, operating costs and expenses for the third quarter of 2010 included $6.6 million of the $26.8 million of total non-cash expense we recorded in connection with liquidation of the Employee Partnerships in August 2010. The remaining $20.2 million of non-cash expense related to the Employee Partnership liquidations is a component of our general and administrative costs for the third quarter of 2010 (see below).

Changes in our revenues and operating costs and expenses quarter-to-quarter are explained in part by changes in energy commodity prices. For example, higher energy commodity prices result in an increase in revenues attributable to the sale of NGLs, natural gas, crude oil and petrochemicals and refined products; however, these same higher energy commodity prices also increase the associated cost of sales as purchase prices rise. The weighted-average indicative market price for NGLs was $1.50 per gallon during the third quarter of 2011 versus $1.04 per gallon during the third quarter of 2010 – a 44% quarter-to-quarter increase. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub in Louisiana) averaged $4.20 per MMBtu during the third quarter of 2011 versus $4.38 per MMBtu during the third quarter of 2010. Also, the market price of crude oil (as measured on the NYMEX) averaged $89.76 per barrel during the third quarter of 2011 compared to $76.20 per barrel during the third quarter of 2010. See “Selected Price and Volumetric Data” included within this Item 2 for historical energy commodity pricing information relevant to our business.

General and administrative costs were $50.0 million for the third quarter of 2011 compared to $70.1 million for the third quarter of 2010, a $20.1 million quarter-to-quarter decrease. The third quarter of

2011 includes $10.0 million of transaction expenses related to the Duncan Merger. General and administrative costs for the third quarter of 2010 include $20.2 million of non-cash charges related to the Employee Partnership liquidations and $13.9 million of transaction expenses related to the Holdings Merger. The remainder of our general and administrative costs increased $4.0 million quarter-to-quarter primarily due to higher employee compensation expenses.

Equity earnings from unconsolidated affiliates were $8.6 million for the third quarter of 2011 compared to $5.6 million for the third quarter of 2010, a $3.0 million quarter-to-quarter increase. Equity earnings from Energy Transfer Equity increased $14.2 million quarter-to-quarter. Collectively, equity earnings from our other equity method investees decreased $11.2 million quarter-to-quarter primarily due to the effects of lower throughput volumes on pipeline assets owned by Seaway Crude Pipeline Company ("Seaway"), Centennial Pipeline LLC ("Centennial") and our equity method investees operating in the Gulf of Mexico during the third quarter of 2011.

Operating income for the third quarter of 2011 was $681.1 million compared to $543.2 million for the third quarter of 2010. Collectively, the aforementioned changes in consolidated revenues, costs and expenses and equity earnings resulted in a $137.9 million quarter-to-quarter increase in operating income.

Interest expense was $189.0 million for the third quarter of 2011 compared to $192.0 million for the third quarter of 2010. The $3.0 million quarter-to-quarter decrease in interest expense is primarily due to a lower weighted-average interest rate associated with our debt obligations during the third quarter of 2011 compared to the third quarter of 2010. Our average debt principal balances for the third quarters of 2011 and 2010 were $14.84 billion and $13.77 billion, respectively. The increase in the average debt balance between the two periods was primarily due to debt incurred to partially fund our capital investments and for working capital needs. Capitalized interest was $33.1 million for the third quarter of 2011 compared to $12.5 million for the third quarter of 2010. Interest costs attributable to ongoing construction activities are capitalized until the related asset is placed in service, at which time such costs are reflected in interest expense.

Provision for income taxes increased from $4.9 million in the third quarter of 2010 to $11.6 million in the third quarter of 2011 primarily due to increased expense for the Revised Texas Franchise Tax as a result of newly constructed assets located in Texas being placed into commercial service.

Consolidated net income increased $131.9 million quarter-to-quarter to $479.5 million for the third quarter of 2011 from $347.6 million for the third quarter of 2010. Net income attributable to noncontrolling interests was $8.1 million for the third quarter of 2011 compared to $310.6 million for the third quarter of 2010, which included $296.6 million attributable to the limited partners of Enterprise other than Holdings. For periods prior to the Holdings Merger (i.e., prior to November 22, 2010), that portion of Enterprise's net income attributable to its limited partner interests owned by third parties and related parties other than Holdings is presented as a component of net income attributable to noncontrolling interests. See Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for information regarding noncontrolling interests. Net income attributable to partners increased $434.4 million quarter-to-quarter to $471.4 million for the third quarter of 2011 from $37.0 million for the third quarter of 2010.

The following information highlights significant quarter-to-quarter variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $547.6 million for the third quarter of 2011 compared to $397.2 million for the third quarter of 2010, a $150.4 million quarter-to-quarter increase. The third quarter of 2011 includes $3.7 million of gains related to cash proceeds from business interruption insurance claims. The following paragraphs provide a discussion of segment results excluding gains from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $345.5 million for the third quarter of 2011 compared to $223.7 million for the third quarter of 2010, a

$121.8 million quarter-to-quarter increase. Gross operating margin from our NGL marketing activities increased $63.0 million quarter-to-quarter due to higher sales margins. Gross operating margin from our natural gas processing plants located in the Rocky Mountains increased $37.1 million quarter-to-quarter primarily due to the effects of (i) higher equity NGL production and fee-based processing volumes and (ii) higher processing margins during the third quarter of 2011 compared to the third quarter of 2010. Collectively, gross operating margin from our natural gas processing facilities in southern Louisiana and the San Juan and Permian Basins increased $18.3 million quarter-to-quarter primarily due to higher natural gas processing margins during the third quarter of 2011 compared to the third quarter of 2010. Higher fee-based processing volumes at our natural gas processing facilities in South Texas during the third quarter of 2011 compared to the third quarter of 2010 offset the effects of a quarter-to-quarter decrease in equity NGL production. Total fee-based processing volumes increased to 3.8 Bcf/d during the third quarter of 2011 from 2.7 Bcf/d during the third quarter of 2010. Equity NGL production decreased to 114 MBPD during the third quarter of 2011 from 122 MBPD during the third quarter of 2010.

Gross operating margin from our NGL pipelines and related storage business was $145.9 million for the third quarter of 2011 compared to $135.8 million for the third quarter of 2010, a $10.1 million quarter-to-quarter increase. Total NGL transportation volumes decreased to 2,241 MBPD during the third quarter of 2011 from 2,326 MBPD during the third quarter of 2010. Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased $15.4 million period-to-period primarily due to an increase in revenues attributable to changes in the mix of transportation services provided to customers (e.g., increased long-haul delivery volumes and changes in delivery destinations) during the third quarter of 2011 compared to the third quarter of 2010 and an increase in system-wide tariffs in July 2011.

Gross operating margin from our South Texas NGL System increased $4.5 million quarter-to-quarter primarily due to a $6.8 million charge we recorded during the third quarter of 2010 relating to a dispute involving a pipeline segment on this system. Collectively, gross operating margin from our NGL pipelines in southern Louisiana decreased $5.0 million quarter-to-quarter primarily due to lower transportation volumes. The quarter-to-quarter decrease in NGL transportation volumes on our South Louisiana pipelines is due to (i) maintenance-related downtime at regional natural gas processing plants and third-party Gulf of Mexico production platforms and (ii) the shut-in of third-party Gulf of Mexico production platforms in preparation for Tropical Storm Lee during the third quarter of 2011. Gross operating margin from our Houston Ship Channel import/export terminal and a related pipeline decreased $3.7 million quarter-to-quarter primarily due to higher maintenance and utility expenses in the third quarter of 2011, including the costs of a major maintenance turnaround project at the terminal, compared to the third quarter of 2010.

Gross operating margin from our NGL fractionation business was $52.5 million for the third quarter of 2011 compared to $37.7 million for the third quarter of 2010, a $14.8 million quarter-to-quarter increase. Our NGL fractionation volumes were 554 MBPD during the third quarter of 2011 compared to 476 MBPD during the third quarter of 2010. Gross operating margin from our Mont Belvieu NGL fractionators increased $10.2 million quarter-to-quarter primarily due to higher NGL fractionation volumes and fees. During the fourth quarter of 2010, we placed into service a fourth NGL fractionator at our Mont Belvieu complex, which added more than 75 MBPD of NGL fractionation capacity at this key industry hub. Gross operating margin from our Norco NGL fractionation facility increased $4.7 million quarter-to-quarter primarily due to higher NGL prices, which resulted in higher revenues associated with percent-of-liquids contracts and product blending activities.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $156.0 million for the third quarter of 2011 compared to $154.1 million for the third quarter of 2010, a $1.9 million quarter-to-quarter increase. Onshore natural gas transportation volumes were 12.38 TBtus/d during the third quarter of 2011 compared to 11.67 TBtus/d during the third quarter of 2010.

Gross operating margin from our onshore natural gas pipelines and related marketing business was $145.6 million for the third quarter of 2011 compared to $141.4 million for the third quarter of 2010, a $4.2 million quarter-to-quarter increase. Gross operating margin from our Texas Intrastate System increased

$15.1 million quarter-to-quarter primarily due to higher firm capacity reservation revenues and a quarter-to-quarter increase of 448 BBtus/d in natural gas throughput volumes. Increased natural gas production volumes from the Eagle Ford Shale supply basin resulted in stronger demand for our natural gas transportation services during the third quarter of 2011 compared to the same period last year. The quarter-to-quarter increase in transportation volumes on our Texas Intrastate System was also due to greater demand from gas-fired electric generation utilities as a result of record heat in Texas during the third quarter of 2011. Gross operating margin from our State Line Gathering System increased $3.2 million quarter-to-quarter primarily due to the effects of a 116 BBtus/d increase in natural gas gathering volumes. Collectively, gross operating margin from our San Juan and Jonah Gathering Systems decreased $10.1 million quarter-to-quarter primarily due to higher maintenance expenses and lower throughput volumes during the third quarter of 2011 compared to the third quarter of 2010. Natural gas throughput volumes on these systems decreased a combined 159 BBtus/d quarter-to-quarter. Gross operating margin from our associated natural gas marketing activities decreased $3.4 million quarter-to-quarter primarily due to mark-to-market results related to certain derivative contracts. Gross operating margin from our natural gas storage business was $10.4 million for the third quarter of 2011 compared to $12.7 million for the third quarter of 2010, a $2.3 million quarter-to-quarter decrease.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $67.4 million for the third quarter of 2011 compared to $35.0 million for the third quarter of 2010, a $32.4 million quarter-to-quarter increase. Total onshore crude oil transportation volumes were 725 MBPD during the third quarter of 2011 compared to 684 MBPD during the third quarter of 2010. Gross operating margin from our crude oil marketing and related activities increased $22.8 million quarter-to-quarter primarily due to higher sales volumes and margins during the third quarter of 2011 compared to the third quarter of 2010. Our crude oil marketing activities benefited from increased crude oil production volumes from the Eagle Ford Shale, Barnett Shale and West Texas supply basins. Collectively, gross operating margin from our South Texas System, West Texas System and Basin Pipeline increased $11.3 million quarter-to-quarter primarily due to a 42 MBPD increase in throughput volumes and higher average fees during the third quarter of 2011. Equity earnings from our investment in Seaway decreased $2.6 million quarter-to-quarter primarily due to lower transportation volumes during the third quarter of 2011 compared to the third quarter of 2010. Seaway continues to be impacted by the lack of demand for northbound transportation to the oversupplied Cushing hub.

Offshore Pipelines & Services. Gross operating margin from this business segment was $53.9 million for the third quarter of 2011 compared to $68.3 million for the third quarter of 2010, a $14.4 million quarter-to-quarter decrease. Results for the third quarter of 2010 include $8.2 million of gains related to insurance proceeds. As discussed in the following paragraphs, segment gross operating margin decreased $6.2 million quarter-to-quarter excluding insurance related-gains.

Gross operating margin from our offshore crude oil pipeline business was $18.5 million for the third quarter of 2011 compared to $22.2 million for the third quarter of 2010, a $3.7 million quarter-to-quarter decrease. Our offshore crude oil transportation volumes averaged 259 MBPD during the third quarter of 2011 compared to 299 MBPD during the third quarter of 2010. Equity earnings from our investment in Cameron Highway Oil Pipeline Company ("Cameron Highway") decreased $3.7 million quarter-to-quarter primarily due to lower throughput volumes. Net to our interest, crude oil throughput volumes on the Cameron Highway pipeline decreased 44 MBPD quarter-to-quarter primarily due to construction and maintenance-related downtime during the third quarter of 2011 at certain third-party upstream platforms and producing wells.

Gross operating margin from our offshore natural gas pipeline business was $10.4 million for the third quarter of 2011 compared to $9.3 million for the third quarter of 2010, a $1.1 million quarter-to-quarter increase. Total offshore natural gas transportation volumes were 1.01 TBtus/d during the third quarter of 2011 versus 1.14 TBtus/d during the third quarter of 2010. Improved results from our Anaconda system attributable to increased volumes and a system expansion were partially offset by the impact of lower transportation volumes on the remainder of our offshore natural gas pipeline assets.

Gross operating margin from our offshore platform services business was $25.0 million for the third quarter of 2011 compared to $28.6 million for the third quarter of 2010, a $3.6 million quarter-to-quarter decrease. On a net basis to our interest, platform natural gas processing volumes were 376 MMcf/d during the third quarter of 2011 compared to 442 MMcf/d during the third quarter of 2010. The quarter-to-quarter decrease in gross operating margin is primarily due to lower volumes at our Independence Hub platform and our assets in the Viosca Knoll and Garden Banks areas of the Gulf of Mexico during the third quarter of 2011 compared to the third quarter of 2010.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was $145.6 million for the third quarter of 2011 compared to $166.2 million for the third quarter of 2010, a $20.6 million quarter-to-quarter decrease.

Gross operating margin from propylene fractionation and related activities was $37.3 million for the third quarter of 2011 compared to $53.1 million for the third quarter of 2010, a $15.8 million quarter-to-quarter decrease. Propylene fractionation volumes were 74 MBPD during the third quarter of 2011 compared to 77 MBPD during the third quarter of 2010. The quarter-to-quarter decrease in gross operating margin is primarily due to lower propylene fractionation volumes and sales margins during the third quarter of 2011 compared to the third quarter of 2010. Results for the third quarter of 2010 benefited from the combined effects of high demand for propylene and reduced propylene production from third-party petrochemical facilities.

Gross operating margin from butane isomerization was $32.7 million for the third quarter of 2011 compared to $23.1 million for the third quarter of 2010, a $9.6 million quarter-to-quarter increase. Butane isomerization volumes increased to 105 MBPD during the third quarter of 2011 from 95 MBPD during the third quarter of 2010. The quarter-to-quarter increase in gross operating margin is primarily due to increased by-product production and associated sales margins.

Gross operating margin from octane enhancement and associated plant production was $38.7 million for the third quarter of 2011 compared to $20.6 million for the third quarter of 2010. The $18.1 million quarter-to-quarter increase was primarily due to higher margins from the sale of motor gasoline additives during the third quarter of 2011 compared to the third quarter of 2010.

Gross operating margin from our refined products pipelines and related activities was $21.5 million for the third quarter of 2011 compared to $51.0 million for the third quarter of 2010, a $29.5 million quarter-to-quarter decrease. Pipeline transportation volumes for the refined products business decreased to 677 MBPD during the third quarter of 2011 from 712 MBPD during the third quarter of 2010. Gross operating margin from our Products Pipeline System decreased $16.8 million quarter-to-quarter primarily due to higher maintenance and pipeline integrity expenses during the third quarter of 2011 compared to the third quarter of 2010. Equity earnings from our investment in Centennial decreased $3.1 million quarter-to-quarter primarily due to lower transportation volumes. Net to our interest, transportation volumes on the Centennial pipeline decreased 35 MBPD quarter-to-quarter. Structural shifts in population, reduced demand and increased refinery production in the Midwest have contributed to a decline in demand for the transportation of refined products from the Gulf Coast to the Midwest. Gross operating margin from the marketing of refined products decreased $10.3 million quarter-to-quarter primarily due to lower sales margins associated with forward sales contracts.

Gross operating margin from marine transportation and other services was $15.4 million for the third quarter of 2011 compared to $18.4 million for the third quarter of 2010, a $3.0 million quarter-to-quarter decrease. Gross operating margin from marine transportation decreased $4.3 million quarter-to-quarter due to lower revenues resulting from our sale of marine transportation vessels in February 2011 that comprised our former bunker fuel transportation fleet. Gross operating margin from other services increased $1.3 million quarter-to-quarter primarily due to our acquisition of truck transport operations from EPCO in September 2010.

Other Investments. Our equity earnings from Energy Transfer Equity were $2.3 million for the third quarter of 2011 compared to a loss of $11.9 million for the third quarter of 2010, a $14.2 million quarter-to-quarter increase. Our equity income from this investment was reduced by $7.1 million and $9.2 million of excess cost amortization during the third quarters of 2011 and 2010, respectively. The equity income we recorded from Energy Transfer Equity for the third quarter of 2011 is based on our estimate of its net income attributable to partners. According to financial statements filed with the SEC, Energy Transfer Equity's net income attributable to partners for the third quarter of 2010 was a loss of $15.3 million, which included $66.4 million of charges in connection with the termination of interest rate swaps.

Comparison of Nine Months Ended September 30, 2011 with Nine Months Ended September 30, 2010

Revenues for the first nine months of 2011 were $32.73 billion compared to $24.16 billion for the first nine months of 2010, an $8.57 billion period-to-period increase. Consolidated revenues from the sale of NGLs increased $2.54 billion period-to-period primarily due to higher sales prices during the first nine months of 2011 compared to the first nine months of 2010. Revenues from the sale of natural gas decreased $145.0 million period-to-period primarily due to lower sales prices. Crude oil sales revenues increased $3.86 billion period-to-period attributable to both higher sales prices and volumes. Consolidated revenues from the sale of petrochemicals and refined products increased $2.01 billion period-to-period primarily due to higher propylene and refined products sales prices during the first nine months of 2011 compared to the first nine months of 2010. Consolidated revenues also increased $222.6 million period-to-period due to (i) the addition of revenues from businesses we acquired and assets we constructed and placed into service since the third quarter of 2010 and (ii) the timing of the State Line and Fairplay acquisitions in May 2010 (i.e., 2010 includes only a partial period of revenues from these acquired gathering systems). Revenues from the remainder of our midstream services increased $84.8 million period-to-period largely due to increased natural gas production volumes from the Eagle Ford Shale supply basin, which resulted in higher natural gas processing and pipeline transportation revenues on our assets in South Texas during the first nine months of 2011 compared to the first nine months of 2010.

Operating costs and expenses were $30.68 billion for the first nine months of 2011 compared to $22.41 billion for the first nine months of 2010, an $8.27 billion period-to-period increase. The cost of sales of our marketing activities increased $6.79 billion period-to-period primarily due to higher crude oil sales volumes and, with the exception of natural gas prices, higher energy commodity prices. The operating costs and expenses of our natural gas processing plants increased $1.01 billion period-to-period primarily due to higher natural gas processing volumes and NGL prices during the first nine months of 2011 relative to the first nine months of 2010. In general, higher NGL prices result in increased operating costs associated with percent-of-proceeds and margin-band types of natural gas processing contracts. Consolidated operating costs and expenses also increased $183.7 million period-to-period due to (i) the addition of operating costs from businesses we acquired and assets we constructed and placed into service since the third quarter of 2010 and (ii) the timing of the State Line and Fairplay acquisitions in May 2010 (i.e., 2010 includes only a partial period of operating costs from these acquired gathering systems). Operating expenses for the first nine months of 2010 included $6.6 million of non-cash expense related to the Employee Partnership liquidations and $56.6 million of insurance-related gains recorded in connection with our disposition of certain offshore assets.

Changes in our revenues and operating costs and expenses period-to-period are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.45 per gallon during the first nine months of 2011 versus $1.13 per gallon during the first nine months of 2010 – a 28% period-to-period increase. The Henry Hub market price of natural gas averaged $4.21 per MMBtu during the first nine months of 2011 versus $4.59 per MMBtu during the first nine months of 2010. The NYMEX crude oil market price averaged $95.48 per barrel during the first nine months of 2011 compared to $77.65 per barrel during the first nine months of 2010 – a 23% period-to-period increase.

General and administrative costs were $138.3 million for the first nine months of 2011 compared to $150.9 million for the first nine months of 2010, a $12.6 million period-to-period decrease. The first nine months of 2011 include $11.5 million of transaction expenses related to the Duncan Merger. General and administrative costs for the first nine months of 2010 included $20.2 million of non-cash charges related to the Employee Partnership liquidations and $13.9 million of transaction expenses related to the Holdings

Merger. The remainder of our general and administrative costs increased $10.0 million period-to-period primarily due to higher employee compensation expenses.

Equity earnings from our unconsolidated affiliates were $35.9 million for the first nine months of 2011 compared to $43.2 million for the first nine months of 2010. Collectively, equity earnings from Seaway, Centennial and our investees operating in the Gulf of Mexico decreased $30.0 million period-to-period primarily due to lower pipeline throughput volumes during the first nine months of 2011 compared to the first nine months of 2010. Equity earnings from Energy Transfer Equity increased $18.3 million period-to-period. Collectively, equity earnings from our other equity method investees increased $4.4 million period-to-period primarily due to improved results from our investments in midstream energy companies operating in southern Louisiana.

Operating income for the first nine months of 2011 was $1.95 billion compared to $1.64 billion for the first nine months of 2010. Collectively, the aforementioned changes in consolidated revenues, costs and expenses and equity earnings resulted in a $308.1 million period-to-period increase in operating income.

Interest expense increased to $561.1 million for the first nine months of 2011 from $529.1 million for the first nine months of 2010. The $32.0 million period-to-period increase in interest expense is primarily due to non-cash mark-to-market expenses recorded during the first nine months of 2011 in connection with undesignated interest rate swaps and a higher average outstanding debt principal balance during the first nine months of 2011 compared to the first nine months of 2010. Average debt principal outstanding increased to $14.44 billion during the first nine months of 2011 from $13.04 billion during the first nine months of 2010. Capitalized interest was $75.1 million for the first nine months of 2011 compared to $33.5 million for the first nine months of 2010. Interest costs attributable to ongoing construction activities are capitalized until the related asset is placed in service, at which time such costs are reflected in interest expense.

Consolidated net income increased $268.1 million period-to-period to $1.36 billion for the first nine months of 2011 from $1.09 billion for the first nine months of 2010. Net income attributable to noncontrolling interests was $36.7 million for the first nine months of 2011 compared to $933.4 million for the first nine months of 2010, which included $887.3 million attributable to the limited partners of Enterprise other than Holdings. For periods prior to the Holdings Merger, that portion of Enterprise's net income attributable to its limited partner interests owned by third parties and related parties other than Holdings is presented as a component of net income attributable to noncontrolling interests. Net income attributable to partners increased $1.16 billion period-to-period to $1.33 billion for the first nine months of 2011 from $161.0 million for the first nine months of 2010.

The following information highlights significant period-to-period variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $1.55 billion for the first nine months of 2011 compared to $1.28 billion for the first nine months of 2010, a $274.2 million period-to-period increase. The first nine months of 2011 include $3.7 million of gains related to cash proceeds from business interruption insurance claims. The following paragraphs provide a discussion of segment results excluding gains from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $926.4 million for the first nine months of 2011 compared to $751.3 million for the first nine months of 2010, a $175.1 million period-to-period increase. Gross operating margin from our NGL marketing activities increased $112.4 million period-to-period primarily due to higher sales margins. Gross operating margin from our natural gas processing plants located in the Rocky Mountains increased $29.5 million period-to-period primarily due to the combined effects of higher natural gas processing margins and fee-based processing volumes during the first nine months of 2011 compared to the first nine months of 2010. Collectively, gross operating margin from our natural gas processing facilities in southern Louisiana and the San Juan and Permian Basins increased $25.6 million period-to-period primarily due to higher natural gas processing margins during the first nine months of 2011 compared to the first nine months of 2010. Natural gas processing activities on the Fairplay gathering system, which we acquired in May 2010, contributed $9.0 million of the period-to-period increase in gross operating margin.

Gross operating margin from our NGL pipelines and related storage business was $468.4 million for the first nine months of 2011 compared to $424.8 million for the first nine months of 2010, a $43.6 million period-to-period increase. Total NGL transportation volumes increased to 2,286 MBPD during the first nine months of 2011 from 2,254 MBPD during the first nine months of 2010. Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased $37.4 million period-to-period primarily due to an increase in revenues attributable to changes in the mix of transportation services provided to customers (e.g., increased long-haul delivery volumes and changes in delivery destinations) during the first nine months of 2011 compared to the first nine months of 2010 and an increase in system-wide tariffs in July 2011. Gross operating margin from our NGL storage activities increased $8.3 million period-to-period primarily due to an increase in storage and terminaling fees, which was partially offset by the $5.0 million property damage deductible we expensed in February 2011 related to the West Storage incident at our Mont Belvieu complex. See "Significant Recent Developments" within this Item 2 for information regarding a February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility.

Gross operating margin from our South Texas NGL System increased $6.9 million period-to-period primarily due to a $6.8 million charge we recorded during the third quarter of 2010 related to a dispute involving a pipeline segment on this system. Gross operating margin from the Dixie Pipeline and related NGL terminals decreased $10.4 million period-to-period primarily due to an 18 MBPD decrease in transportation volumes and higher pipeline integrity expenses during the first nine months of 2011. Gross operating margin from our Houston Ship Channel import/export terminal and a related pipeline decreased $4.2 million period-to-period primarily due to higher maintenance and other operating expenses during the first nine months of 2011. Gross operating margin from the remainder of our NGL pipelines and related storage business increased $5.6 million period-to-period primarily due to increased net operational measurement and well gains during the first nine months of 2011 compared to the first nine months of 2010.

Gross operating margin from our NGL fractionation business was $151.2 million for the first nine months of 2011 compared to $99.4 million for the first nine months of 2010, a $51.8 million period-to-period increase. Our NGL fractionation volumes were 557 MBPD during the first nine months of 2011 compared to 471 MBPD during the first nine months of 2010. Gross operating margin from our Mont Belvieu NGL fractionators increased $40.1 million period-to-period primarily due to higher NGL fractionation volumes and fees. During the fourth quarter of 2010, we placed into service a fourth NGL fractionator at our Mont Belvieu complex, which added more than 75 MBPD of NGL fractionation capacity at this key industry hub. Gross operating margin from our Norco NGL fractionation facility increased $9.7 million period-to-period primarily due to higher NGL prices, which resulted in higher revenues associated with percent-of-liquids contracts and product blending activities.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $476.3 million for the first nine months of 2011 compared to $391.3 million for the first nine months of 2010, an $85.0 million period-to-period increase. Onshore natural gas transportation volumes were 11.99 TBtus/d during the first nine months of 2011 compared to 11.43 TBtus/d during the first nine months of 2010.

Gross operating margin from our onshore natural gas pipelines and related marketing business was $442.2 million for the first nine months of 2011 compared to $352.8 million for the first nine months of 2010, an $89.4 million period-to-period increase. Gross operating margin from our Texas Intrastate System increased $39.1 million period-to-period primarily due to higher firm capacity reservation revenues and increased natural gas throughput volumes produced from the Eagle Ford Shale supply basin. Gross operating margin from our natural gas marketing activities increased $29.5 million period-to-period primarily due to higher sales margins. Our State Line and Fairplay natural gas gathering systems, which we acquired in May 2010, contributed $25.3 million of the period-to-period increase in gross operating margin. Gross operating margin from the remainder of our onshore natural gas pipelines and related marketing business decreased $4.5 million period-to-period primarily due to lower gathering volumes on our Jonah Gathering System.

Gross operating margin from our natural gas storage business was $34.1 million for the first nine months of 2011 compared to $38.5 million for the first nine months of 2010. The $4.4 million period-to-period decrease in gross operating margin is primarily due to lower demand for interruptible natural gas storage services and higher operating expenses at our Mississippi facilities during the first nine months of 2011 compared to the first nine months of 2010. See "Significant Recent Developments" within this Item 2 for information regarding our execution of definitive agreements to sell our Mississippi natural gas storage facilities.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $167.0 million for the first nine months of 2011 compared to $87.6 million for the first nine months of 2010, a $79.4 million period-to-period increase. Total onshore crude oil transportation volumes averaged 678 MBPD during the first nine months of 2011 and 2010. Gross operating margin from our crude oil marketing and related activities increased $63.5 million period-to-period primarily due to higher sales volumes and margins. Our crude oil marketing activities benefited from increased crude oil production volumes from the Eagle Ford Shale, Barnett Shale and West Texas supply basins. Collectively, gross operating margin from our South Texas System, West Texas System, Red River Pipeline and Basin Pipeline increased $23.6 million period-to-period primarily due to a 49 MBPD increase in throughput volumes and higher average fees during the first nine months of 2011.

Equity earnings from our investment in Seaway decreased $10.7 million period-to-period primarily due to lower volumes delivered to the Cushing hub from the Texas Gulf Coast during the first nine months of 2011 compared to the first nine months of 2010. Net to our interest, throughput volumes on the Seaway pipeline system decreased 49 MBPD period-to-period. As a result of an oversupply of crude oil at the Cushing hub, crude oil at the hub is priced at a substantial discount to oil markets on the Gulf Coast. This has led refiners in the Midwest to source a significant amount of their crude oil feedstocks from the Cushing hub rather than shipping such volumes northward from the Gulf Coast (e.g., by using the Seaway pipeline). This situation is expected to continue until the oversupply issue is resolved at the Cushing hub.

Collectively, gross operating margin from the remainder of our onshore crude oil businesses increased $3.0 million period-to-period primarily due to improved operating results from our terminal operations in Midland, Texas and Cushing, Oklahoma.

Offshore Pipelines & Services. Gross operating margin from this business segment was $168.6 million for the first nine months of 2011 compared to $232.2 million for the first nine months of 2010, a $63.6 million period-to-period decrease. Results for the first nine months of 2010 include $27.5 million of gains related to insurance proceeds. Excluding gains from insurance proceeds, gross operating margin from this business segment decreased $36.1 million period-to-period primarily due to the effects of last year's federal offshore drilling moratorium and the ongoing deliberations of federal authorities to approve drilling and well workover permits. Although crude oil and natural gas drilling activity has resumed on a limited basis since last year's drilling moratorium (which was in effect from May 2010 to October 2010), certain of our offshore pipeline and platform assets continue to experience reduced throughput volumes, as existing wells experience natural production declines. We expect that drilling activity in the Gulf of Mexico will increase in the future as federal agencies allow exploration and production companies to proceed with the drilling of new wells.

Gross operating margin from our offshore crude oil pipeline business was $57.6 million for the first nine months of 2011 compared to $73.4 million for the first nine months of 2010, a $15.8 million period-to-period decrease. Total offshore crude oil transportation volumes averaged 279 MBPD during the first nine months of 2011 compared to 325 MBPD during the first nine months of 2010. Collectively, equity earnings from our investments in Poseidon Oil Pipeline Company, L.L.C. ("Poseidon") and Cameron Highway decreased $11.4 million period-to-period primarily due to lower throughput volumes.

Net to our interest, crude oil throughput volumes on the Poseidon and Cameron Highway pipelines decreased 41 MBPD period-to-period. Collectively, gross operating margin from the remainder of our offshore crude oil pipeline business decreased $4.4 million period-to-period primarily due to a 19 MBPD decrease in throughput volumes on our Shenzi and Constitution Oil Pipelines.

Gross operating margin from our offshore natural gas pipeline business was $28.1 million for the first nine months of 2011 compared to $35.6 million for the first nine months of 2010, a $7.5 million period-to-period decrease. Total offshore natural gas transportation volumes were 1,067 BBtus/d during the first nine months of 2011 versus 1,284 BBtus/d during the first nine months of 2010. Gross operating margin from our Independence Trail pipeline decreased $10.8 million period-to-period primarily due to lower transportation volumes. Natural gas transportation volumes on our Independence Trail pipeline decreased to 472 BBtus/d during the first nine months of 2011 from 613 BBtus/d during the first nine months of 2010 as a result of lower volumes from the Independence Hub platform (see below). Gross operating margin from our High Island Offshore System decreased $4.2 million period-to-period primarily due to the first nine months of 2010 including $4.2 million of revenues attributable to a rate case settlement. Gross operating margin from our Anaconda system increased $3.3 million period-to-period primarily due to a system extension we completed and placed into service during the third quarter of 2011. Collectively, gross operating margin from the remainder of our offshore natural gas pipeline business increased $4.2 million period-to-period primarily due to lower operating expenses on our Viosca Knoll Gathering System during the first nine months of 2011 compared to the first nine months of 2010.

Gross operating margin from our offshore platform services business was $82.9 million for the first nine months of 2011 compared to $95.7 million for the first nine months of 2010, a $12.8 million period-to-period decrease. On a net basis to our interest, platform natural gas processing volumes were 412 MMcf/d during the first nine months of 2011 compared to 547 MMcf/d during the first nine months of 2010. The period-to-period decrease in gross operating margin is primarily due to lower natural gas processing volumes from production fields served by our Independence Hub platform as a result of depletion at existing wells, the watering-out of certain wells, and the lingering impact of the federal offshore drilling moratorium which has slowed the drilling of new wells.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was $397.8 million for the first nine months of 2011 compared to $444.3 million for the first nine months of 2010, a $46.5 million period-to-period decrease.

Gross operating margin from propylene fractionation and related activities was $117.3 million for the first nine months of 2011 compared to $163.8 million for the first nine months of 2010, a $46.5 million period-to-period decrease. Propylene fractionation volumes were 72 MBPD during the first nine months of 2011 compared to 78 MBPD during the first nine months of 2010. The period-to-period decrease in gross operating margin is primarily due to lower propylene fractionation volumes and sales margins during the first nine months of 2011 compared to the first nine months of 2010. Results for the first nine months of 2010 benefited from the combined effects of high demand for propylene and reduced propylene production from third-party petrochemical facilities.

Gross operating margin from butane isomerization was $93.1 million for the first nine months of 2011 compared to $64.1 million for the first nine months of 2010, a $29.0 million period-to-period increase. Butane isomerization volumes increased to 99 MBPD during the first nine months of 2011 from 89 MBPD during the first nine months of 2010. The period-to-period increase in gross operating margin is primarily due to increased by-product production and associated sales margins.

Gross operating margin from octane enhancement and associated plant production was $82.0 million for the first nine months of 2011 compared to $35.6 million for the first nine months of 2010. The $46.4 million period-to-period increase was primarily due to higher motor gasoline additive sales volumes and margins during the first nine months of 2011 compared to the first nine months of 2010.

Gross operating margin from our refined products pipelines and related activities was $62.0 million for the first nine months of 2011 compared to $130.8 million for the first nine months of 2010, a

$68.8 million period-to-period decrease. Pipeline transportation volumes for the refined products business decreased to 651 MBPD during the first nine months of 2011 from 735 MBPD during the first nine months of 2010. Gross operating margin from our Products Pipeline System decreased $51.2 million period-to-period primarily due to lower throughput volumes and higher operating expenses during the first nine months of 2011 compared to the first nine months of 2010. Equity earnings from our investment in Centennial decreased $6.8 million period-to-period primarily due to lower transportation volumes. Net to our interest, transportation volumes on the Centennial pipeline decreased 21 MBPD period-to-period. Structural shifts in population, reduced demand and increased refinery production in the Midwest have contributed to a decline in demand for the transportation of refined products from the Gulf Coast to the Midwest. Gross operating margin from the marketing of refined products decreased $11.2 million period-to-period primarily due to lower sales margins associated with forward sales contracts.

Of the total period-to-period decrease in gross operating margin from the Products Pipeline System, we estimate that $20.4 million is due to lower revenues and higher operating expenses attributable to the impact of a pipeline leak that occurred in New York state in the third quarter of 2010. Following our repair of the leak, the affected segment of pipe was tested and returned to service in February 2011. The remaining $30.8 million period-to-period decrease in gross operating margin from our Products Pipeline System is primarily due to lower volumes delivered to Northeast U.S. markets and higher operating costs such as expenses for maintenance and pipeline integrity projects.

Gross operating margin from marine transportation and other services was $43.4 million for the first nine months of 2011 compared to $50.0 million for the first nine months of 2010, a $6.6 million period-to-period decrease. Gross operating margin from marine transportation decreased $11.4 million period-to-period primarily due to lower revenues resulting from our sale of marine transportation vessels in February 2011 that comprised our former bunker fuel transportation fleet. Gross operating margin from other services increased $4.8 million period-to-period primarily due to our acquisition of truck transport operations from EPCO in September 2010.

Other Investments. Our equity earnings from Energy Transfer Equity were $11.3 million for the first nine months of 2011 compared to a loss of $7.0 million for the first nine months of 2010, an $18.3 million period-to-period increase. Our equity income from this investment was reduced by $24.6 million and $27.5 million of excess cost amortization during the first nine months of 2011 and 2010, respectively. The equity income we recorded from this investment for the first nine months of 2011 is based on our estimate of Energy Transfer Equity's net income attributable to partners. According to financial statements filed with the SEC, Energy Transfer Equity's net income attributable to partners for the first nine months of 2010 was $116.7 million, which included $66.4 million of charges in connection with the termination of interest rate swaps and a $52.6 million non-cash impairment charge to write-down the carrying value of its investment in Midcontinent Express Pipeline, LLC.

Liquidity and Capital Resources

At September 30, 2011, we had $2.81 billion of liquidity, which is defined as unrestricted cash on hand plus available borrowing capacity under our $3.5 Billion Multi-Year Revolving Credit Facility. Our primary cash requirements are for routine operating expenses, debt service, working capital, capital expenditures, business combinations and distributions to partners. We expect to fund our short-term cash requirements for operating expenses and sustaining capital expenditures using operating cash flows and borrowings under our revolving credit facility. Our expenditures for long-term productive assets (e.g., business expansion projects and acquisitions) are expected to be funded by a variety of sources (either separately or in combination) including the use of operating cash flows, borrowings under our revolving credit facility, and proceeds from divestitures and the issuance of additional equity and debt securities. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements. It is our belief that we will continue to have adequate liquidity and capital resources to fund expected recurring operating and investing activities.

Long-Term Debt

In September 2011, EPO entered into a new $3.5 Billion Multi-Year Revolving Credit Facility that matures in September 2016. Initial borrowings under this variable-rate credit facility were used to refinance and terminate EPO's prior $1.75 Billion Multi-Year Revolving Credit Facility. Future borrowings under the new $3.5 billion revolving credit facility may be used for working capital, capital expenditures, acquisitions and general partnership purposes.

We had approximately $15.05 billion of principal amounts outstanding under consolidated debt agreements at September 30, 2011. In January 2011, EPO issued $750.0 million in principal amount of 5-year unsecured Senior Notes AA and $750.0 million in principal amount of 30-year unsecured Senior Notes BB. Senior Notes AA were issued at 99.901% of their principal amount, have a fixed interest rate of 3.20%, and mature in February 2016. Senior Notes BB were issued at 99.317% of their principal amount, have a fixed interest rate of 5.95%, and mature in February 2041. Net proceeds from the issuance of Senior Notes AA and BB were used (i) to repay $450.0 million in aggregate principal amount of Senior Notes B that matured in February 2011, (ii) to temporarily reduce borrowings outstanding under EPO's $1.75 Billion Multi-Year Revolving Credit Facility and (iii) for general partnership purposes.

In August 2011, EPO issued $650.0 million in principal amount of 10-year unsecured Senior Notes CC and $600.0 million in principal amount of 30-year unsecured Senior Notes DD. Senior Notes CC were issued at 99.790% of their principal amount, have a fixed interest rate of 4.05%, and mature in February 2022. Senior Notes DD were issued at 99.887% of their principal amount, have a fixed interest rate of 5.70%, and mature in February 2042. Net proceeds from the issuance of Senior Notes CC and DD were used (i) to temporarily reduce borrowings outstanding under EPO's $1.75 Billion Multi-Year Revolving Credit Facility and (ii) for general partnership purposes.

We were in compliance with the financial covenants of our consolidated debt agreements at September 30, 2011. For additional information regarding our consolidated debt obligations, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Registration Statements

We may issue additional equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. In July 2010, Enterprise, including EPO, filed a universal shelf registration statement (the "2010 Shelf") with the SEC. The 2010 Shelf allows Enterprise 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 AA and BB in January 2011 and Senior Notes CC and DD in August 2011.

Enterprise also has a registration statement on file with the SEC in connection with its distribution reinvestment plan ("DRIP"). After taking into account limited partner units issued under this registration statement through September 30, 2011, Enterprise may issue an additional 26,806,721 common units under its DRIP. The following table reflects the number of common units issued and the net cash proceeds received from Enterprise's DRIP during the nine months ended September 30, 2011:

	Number of Common Units Issued	**Net Cash Proceeds**
February 2011 issuance	474,706	$ 19.6
May 2011 issuance	551,058	21.9
August 2011 issuance	582,387	22.0
Total	1,608,151	$ 63.5

In May 2011, Enterprise's original employee unit purchase plan ("EUPP") reached the maximum 1,200,000 common units permitted under the plan and was terminated. A total of 86,141 common units were issued in 2011 under the EUPP, which generated net cash proceeds of $3.6 million.

In September 2011, in connection with the Duncan Merger, the Duncan Energy Partners EUPP was assumed by Enterprise and converted into a new Enterprise EUPP. Enterprise filed a registration statement with the SEC authorizing the issuance of 440,879 common units under the assumed plan. As of September 30, 2011, Enterprise had not issued any of its common units under this plan.

Net cash proceeds received in 2011 from Enterprise's DRIP and terminated EUPP were used to temporarily reduce borrowings outstanding under EPO's revolving credit facilities and for general partnership purposes.

Sale of Energy Transfer Equity Common Units

We own noncontrolling limited partner interests in Energy Transfer Equity, which totaled 30,411,954 common units at September 30, 2011. Our equity investments are a part of our long-term business strategy; however, we may from time-to-time elect to divest of a portion of our equity investments in order to redeploy capital. In May and July 2011, we sold a total of 8,564,136 Energy Transfer Equity common units for net cash proceeds of $333.5 million and recorded aggregate gains of $24.8 million on the sales. Proceeds from these transactions were used for general partnership purposes, including the funding of capital expenditures.

Sale of Ownership Interests in Crystal to Boardwalk

In October 2011, Enterprise announced that it executed definitive agreements to sell all of its ownership interests in Crystal to Boardwalk for $550 million in cash. Proceeds from this sale will be used for general partnership purposes, including the funding of capital expenditures. This transaction is subject to customary regulatory approvals and is expected to close during the fourth quarter of 2011.

Designated Units issued in connection with Holdings Merger

In connection with the Holdings Merger, a privately held affiliate of EPCO agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from Enterprise with respect to a certain number of Enterprise's common units (the "Designated Units") over a five-year period after the merger closing date of November 22, 2010. The number of Designated Units to which the temporary distribution waiver applies is as follows for distributions to be paid, if any, during the following periods: 30,610,000 during 2011; 26,130,000 during 2012; 23,700,000 during 2013; 22,560,000 during 2014; and 17,690,000 during 2015. Distributions paid to partners in February, May, August and November 2011 excluded the initial 30,610,000 Designated Units; however, distributions to be paid, if any, to partners in calendar year 2012 (beginning with the February 2012 distribution) would only exclude 26,130,000 Designated Units. As a result, the number of our distribution-bearing units will increase by 4,480,000 units beginning in February 2012, with additional increases in subsequent years as the number of Designated Units declines.

Credit Ratings

At November 1, 2011, the investment-grade credit ratings of EPO's senior unsecured debt securities were: Baa3 from Moody's Investor Services ("Moody's"); BBB- from Fitch Ratings; and BBB- from Standard and Poor's. In March 2011, Moody's reaffirmed its corporate credit rating of EPO and revised its outlook for EPO's business from "stable" to "positive." On August 1, 2011, Fitch Ratings reaffirmed its corporate credit rating of EPO and revised its outlook for EPO's business from "stable" to "positive." 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.

A downgrade of EPO's credit ratings could result in us posting financial collateral in connection with our guaranty of Centennial's debt, which was $52.1 million at September 30, 2011. Furthermore, we may enter into contracts in connection with our commodity and interest rate hedging activities that may require the posting of financial collateral if EPO's credit ratings were downgraded below investment grade.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our consolidated cash flows from operating, investing and financing activities for the periods indicated (dollars in millions). For additional information regarding our cash flow amounts, please refer to the Unaudited Condensed Statements of Consolidated Cash Flows included under Item 1 of this quarterly report.

	For the Nine Months Ended September 30,	
	2011	**2010**
Net cash flows provided by operating activities	$ 2,228.2	$ 1,443.8
Cash used in investing activities	2,338.6	2,501.5
Cash provided by financing activities	74.0	1,045.0

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 certain 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 Item 1A of our 2010 Form 10-K.

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

Comparison of Consolidated Cash Flows for the Nine Months Ended September 30, 2011 with the Nine Months Ended September 30, 2010

Operating Activities. The $784.4 million increase in net cash flows provided by operating activities was primarily due to the following:

§ Net cash flows from consolidated operations (excluding cash distributions received from unconsolidated affiliates and cash payments for interest) increased $868.4 million period-to-period. The increase in operating cash flows between periods is generally due to increased profitability and the timing of related cash receipts and disbursements.

§ Cash payments for interest increased $60.5 million period-to-period primarily due to an increase in debt obligations. Our average consolidated debt principal outstanding was $14.44 billion during the nine months ended September 30, 2011 compared to $13.04 billion during the nine months ended September 30, 2010.

§ Distributions received from unconsolidated affiliates decreased $23.5 million period-to-period primarily due to reduced distributions from Seaway, Cameron Highway and Poseidon.

Investing Activities. The $162.9 million decrease in cash used for investing activities was primarily due to the following:

§ Cash used for business combinations decreased $1.23 billion period-to-period, primarily due to the acquisition of the State Line and Fairplay natural gas gathering systems for approximately $1.2 billion in May 2010.

§ Proceeds from asset sales and related transactions increased $350.9 million period-to-period, primarily from the sale of approximately 8.6 million Energy Transfer Equity common units for $333.5 million during 2011.

§ Capital spending for property, plant and equipment, net of contributions in aid of construction costs, increased $1.39 billion period-to-period primarily due to our Eagle Ford Shale and Haynesville Shale expansion projects. For additional information regarding our capital spending program, see "Liquidity and Capital Resources – Capital Spending" included within this Item 2.

Financing Activities. As discussed under "Basis of Financial Statement Presentation" within this Item 2, the financial statements of Enterprise prior to the Holdings Merger were those of Holdings. As a result, cash distributions paid to partners for the nine months ended September 30, 2010 represent payments to the former unitholders of Holdings whereas cash distributions paid to partners for the nine months ended September 30, 2011 represent payments to the unitholders of Enterprise. Also, cash distributions paid to noncontrolling interests for nine months ended September 30, 2010 include cash payments to the unitholders of Enterprise (other than Holdings). Cash contributions from noncontrolling interests for the nine months ended September 30, 2010 primarily represent proceeds from Enterprise's equity offerings (other than purchases by Holdings).

The $971.0 million decrease in cash provided by financing activities was primarily due to the following:

§ Cash distributions to partners and noncontrolling interests were a combined $1.51 billion for the nine months ended September 30, 2011 compared to $1.33 billion for the nine months ended September 30, 2010. The increase in cash distributions is primarily due to an increase in the number of Enterprise's distribution-bearing common units outstanding and its quarterly distribution rates.

§ Cash contributions from noncontrolling interests were $4.7 million for the nine months ended September 30, 2011 compared to $1.03 billion for the nine months ended September 30, 2010. The issuance of common units by Enterprise during the nine months ended September 30, 2010 generated $1.03 billion of net cash proceeds.

§ Net cash proceeds from the issuance of Enterprise common units during the nine months ended September 30, 2011 were $67.1 million.

§ Net borrowings under our consolidated debt agreements increased $222.1 million period-to-period. EPO issued $2.75 billion of new senior notes and repaid $450 million in senior notes during the nine months ended September 30, 2011 compared to the issuance of $2.0 billion in senior notes and repayment of $500.0 million in senior notes and $54.0 million of other long-term debt during the nine months ended September 30, 2010. In addition, borrowings under consolidated revolving credit facilities and term loans, including the impact of refinancing the debt of Duncan Energy Partners, decreased approximately $632 million period-to-period.

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 grow our system of assets through the construction of new facilities and to capitalize on expected increases in natural gas and/or crude oil production from resource basins in the Rocky Mountains, Northeastern U.S. and U.S. Gulf Coast regions, including the Barnett Shale, Haynesville Shale, Eagle Ford Shale and Marcellus Shale producing regions. See "Significant Recent Developments" within this Item 2 for information regarding our current and proposed major capital projects, including the start of commercial service on the Haynesville Extension and the formation of a new joint venture to design, construct and operate the Texas Express Pipeline.

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 expect independent oil and natural gas companies to consider similar divestitures.

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

	For the Nine Months Ended September 30,	
	2011	**2010**
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	$ 2,779.9	$ 1,391.2
Capital spending for business combinations (1)	--	1,233.0
Capital spending for investments in unconsolidated affiliates	11.9	6.3
Other investing activities	7.4	--
Total	$ 2,799.2	$ 2,630.5

(1) Capital spending for business combinations in 2010 primarily relates to the $1.2 billion we paid in May 2010 to acquire ownership interests in the entities that own the State Line and Fairplay natural gas gathering systems.

Total capital expenditures were $1.1 billion for the third quarter of 2011, which included $989 million for growth capital projects. Approximately 89% of the growth capital expenditures in the third quarter of 2011 were for the Haynesville Extension ($329 million) and Eagle Ford Shale projects ($521 million). For the nine months ended September 30, 2011, we have spent $2.6 billion on growth capital projects, of which $1.05 billion was for the Haynesville Extension and $1.12 billion for Eagle Ford Shale projects. Sustaining capital expenditures were $81.2 million for the third quarter of 2011 and $217.8 million for the nine months ended September 30, 2011.

Sustaining capital expenditures are capital expenditures (as defined by GAAP) resulting from improvements to and major renewals of existing assets. Such expenditures serve to sustain existing operations but do not generate additional revenues. Growth capital projects result in either (i) additional revenue streams from existing assets or (ii) expand our asset base through construction of new facilities that will generate additional revenue streams. Based on information currently available, we estimate our consolidated capital spending for the remainder of 2011 will be approximately $1.2 billion, which includes estimated expenditures of $1.1 billion for growth capital projects and $60 million for sustaining capital expenditures.

The preceding forecast of consolidated capital expenditures 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 forecasted capital expenditures noted above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

At September 30, 2011, we had approximately $1.40 billion in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction projects involving natural gas pipeline projects in the Eagle Ford Shale and Haynesville Shale and an NGL fractionation facility in Mont Belvieu, Texas.

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,	
	2011	**2010**	**2011**	**2010**
Expensed	$ 22.1	$ 9.5	$ 43.9	$ 28.9
Capitalized	13.1	14.7	39.8	28.2
Total	$ 35.2	$ 24.2	$ 83.7	$ 57.1

We expect the cost of our pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $29.5 million for the remainder of 2011. The cost of our pipeline integrity program was $79.8 million for the year ended December 31, 2010.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our 2010 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;
§ reserves for environmental matters and litigation contingencies; and
§ natural gas imbalances.

When used in the preparation of our 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

For information regarding recent accounting developments, see Note 2 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Other Items

Contractual Obligations

Scheduled Maturities of Long-Term Debt. Since January 1, 2011, we (i) issued Senior Notes AA and BB in January 2011, (ii) repaid our Senior Notes B in February 2011, (iii) issued Senior Notes CC and DD in August 2011, (iv) entered into a new $3.5 Billion Multi-Year Revolving Credit Facility in September 2011 and concurrently terminated our $1.75 Billion Multi-Year Revolving Credit Facility and (v) repaid and terminated Duncan Energy Partners' debt obligations in September 2011 in connection with the Duncan Merger. See Note 10 for additional information regarding our consolidated debt obligations.

Operating Lease Obligations. Lease and rental expense included in costs and expenses was $21.2 million and $18.3 million during the three months ended September 30, 2011 and 2010, respectively. For the nine months ended September 30, 2011 and 2010, lease and rental expense was $63.2 million and $50.6 million, respectively. With the exception of $36.3 million in new lease commitments entered into by our truck transport business, there have been no material changes in our operating lease commitments since those reported in our 2010 Form 10-K.

Purchase Obligations. Full commercial operations on the Haynesville Extension of our Acadian Gas System commenced November 1, 2011. As part of our natural gas marketing activities, we entered into long-term natural gas purchase agreements that were contingent upon completion of the Haynesville Extension. Our firm purchase commitments under these contracts range from 90 days to 10 years. The total estimated payment obligation under these purchase agreements is $3.42 billion (representing approximately 1,006,775 BBtus). These estimated payment obligations are based on natural gas prices in effect at September 30, 2011 applied to all future purchase volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery.

Apart from the Haynesville Extension contracts, there have been no other material changes in our consolidated purchase obligations since those reported in our 2010 Form 10-K. See Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding these firm purchase commitments, including forecasted payment obligations and underlying volumes over the next five years and thereafter.

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 a timing difference between amounts we are required to pay in connection with a loss and amounts we receive from insurance as reimbursement. Any event that materially interrupts the revenues generated by our consolidated operations, or other losses that require us to make material expenditures not covered by insurance, could reduce our ability to pay distributions to our partners and, accordingly, adversely affect the market price of our common units.

For additional information regarding insurance matters, see Note 16 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

See "Significant Recent Developments" included under this Item 2 for information regarding a February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. For additional information regarding insurance matters, see Note 16 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Non-GAAP Reconciliations

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2011	2010	2011	2010
Total segment gross operating margin	$ 972.8	$ 808.9	$ 2,770.7	$ 2,423.9
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(238.3)	(235.1)	(702.4)	(674.5)
Non-cash asset impairment charges	(5.2)	--	(5.2)	(1.5)
Operating lease expenses paid by EPCO	--	(0.2)	(0.3)	(0.5)
Gains from asset sales and related transactions in operating costs and expenses	1.8	39.7	25.4	45.3
General and administrative costs	(50.0)	(70.1)	(138.3)	(150.9)
Operating income	681.1	543.2	1,949.9	1,641.8
Other expense, net	(190.0)	(190.7)	(561.3)	(527.3)
Income before provision for income taxes	$ 491.1	$ 352.5	$ 1,388.6	$ 1,114.5

Off-Balance Sheet Arrangements

In March 2011, Evangeline made the final scheduled payment of $3.2 million on its subordinated note payable. Following this payment, Evangeline no longer has any debt obligations.

In April 2011, Poseidon refinanced its revolving credit facility. The new replacement facility matures in April 2015 and has a borrowing capacity of $125 million, which may be increased to a maximum of $175 million at Poseidon’s option. At September 30, 2011, the principal amount outstanding under the Poseidon revolving credit facility was $92.0 million.

Except for the matters noted above, there have been no other significant changes in our off-balance sheet arrangements since those reported in our 2010 Form 10-K.

Regulatory Matters

For information about regulatory risks involving climate change and greenhouse gas emissions, see Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Related Party Transactions

On September 7, 2011, one of our wholly owned subsidiaries merged with Duncan Energy Partners, and Duncan Energy Partners survived the merger as our wholly owned subsidiary. See “Significant Recent Developments” within this Item 2 for information regarding completion of the Duncan Merger. For additional information regarding our related party transactions, see Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Item 3. *Quantitative and Qualitative Disclosures about Market Risk.*

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with certain anticipated future transactions, we use derivative instruments. Derivatives are financial instruments whose fair value is determined by changes in a specified benchmark such as interest rates or commodity prices. Derivative instruments typically include futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities. See Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding our derivative instruments and hedging 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 2010 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. Therefore, the impact on the fair value of a derivative instrument resulting from a change in interest rates or quoted market prices (as applicable) would normally be offset by a corresponding gain or loss on the hedged debt instrument, inventory value or forecasted transaction assuming: (i) the derivative instrument functions effectively as a hedge of the underlying risk, (ii) the derivative instrument is not closed out in advance of its expected term; and (iii) the hedged forecasted transaction occurs within the expected time period. When considering that the majority of our derivative portfolios are designated as hedges, the sensitivities presented in the quantitative disclosures would most often be expected to have corresponding offsets.

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.

Interest Rate Derivative Instruments

We utilize interest rate swaps, treasury locks 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 following table summarizes our portfolio of interest rate swaps outstanding at September 30, 2011 reflected as fair value hedges or mark-to-market instruments:

Hedged Transaction	Number and Type of Derivative(s) Employed	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes C	1 fixed-to-floating swap	$100.0	1/04 to 2/13	6.4% to 2.3%	Fair value hedge
Senior Notes G	3 fixed-to-floating swaps	$300.0	10/04 to 10/14	5.6% to 1.4%	Fair value hedge
Senior Notes P	7 fixed-to-floating swaps	$400.0	6/09 to 8/12	4.6% to 2.6%	Fair value hedge
Senior Notes AA	10 fixed-to-floating swaps	$750.0	1/11 to 2/16	3.2% to 1.2%	Fair value hedge
Undesignated swaps	6 floating-to-fixed swaps	$600.0	5/10 to 7/14	0.2% to 2.0%	Mark-to-market

The following table summarizes our portfolio of forward starting interest rate swaps outstanding at September 30, 2011. The purpose of these derivative instruments (accounted for as cash flow hedges) is to hedge the expected underlying benchmark interest rates related to forecasted issuances of debt:

Hedged Transaction	Number and Type of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Future debt offering	10 forward starting swaps	$500.0	2/12	4.5%	Cash flow hedge
Future debt offering	7 forward starting swaps	$350.0	8/12	3.7%	Cash flow hedge
Future debt offering	16 forward starting swaps	$1,000.0	3/13	3.7%	Cash flow hedge

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

Scenario	Resulting Classification	Swap Fair Value at September 30, 2011	Swap Fair Value at October 18, 2011
FV assuming no change in underlying interest rates	*Asset*	$ 68.2	$ 61.3
FV assuming 10% increase in underlying interest rates	*Asset*	65.0	57.8
FV assuming 10% decrease in underlying interest rates	*Asset*	71.4	64.8

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

Scenario	Resulting Classification	Forward-Starting Swap Fair Value at September 30, 2011	Forward-Starting Swap Fair Value at October 18, 2011
FV assuming no change in underlying interest rates	*Liability*	$ (263.7)	$ (212.9)
FV assuming 10% increase in underlying interest rates	*Liability*	(222.7)	(168.2)
FV assuming 10% decrease in underlying interest rates	*Liability*	(305.6)	(258.8)

At June 30, 2011, the fair value of our forward starting interest rate swap portfolio, accounted for as cash flow hedges, was $21.0 million (a liability). As a result of a significant decrease in forward London Interbank Offered Rates ("LIBOR") of approximately 39% during the third quarter of 2011, the fair value of this portfolio had decreased to a liability of $263.7 million at September 30, 2011. The fair value of this portfolio has improved slightly since the end of third quarter of 2011 due to the recent increase in LIBOR rates. Any gain or loss ultimately recognized upon settlement of these cash flow hedges would be amortized into earnings as a reduction or increase, respectively, in interest expense over the forecasted hedge period of 10 years.

Commodity Derivative Instruments

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward agreements, futures contracts, fixed-for-float swaps, basis swaps and options contracts.

Our predominant 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 March 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, 2011, this program had hedged future estimated gross margins (before plant operating expenses) of $285.9 million on 8.3 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through March 2012. At October 18, 2011, this program had hedged future estimated gross margins (before plant operating expenses) of $301.0 million on 8.6 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through March 2012.

- § 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 inventory hedging program is to hedge the fair value of natural gas 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 financial 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 summarizes our commodity derivative instruments outstanding at September 30, 2011:

Derivative Purpose	Volume (1) Current (2)	Long-Term (2)	Accounting Treatment
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction ("PTR") (3)	24.8 Bcf	n/a	Cash flow hedge
Forecasted sales of NGLs (4)	6.4 MMBbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted sales of octane enhancement products	1.0 MMBbls	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	10.4 Bcf	0.5 Bcf	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	1.1 MMBbls	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	1.5 MMBbls	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products	1.5 MMBbls	n/a	Cash flow hedge
Forecasted sales of refined products	1.7 MMBbls	n/a	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil	1.0 MMBbls	n/a	Cash flow hedge
Forecasted sales of crude oil	1.3 MMBbls	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (5,6)	351.3 Bcf	65.1 Bcf	Mark-to-market
Refined products risk management activities (6)	1.6 MMBbls	n/a	Mark-to-market
Crude oil risk management activities (6)	5.4 MMBbls	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 2012, January 2013 and December 2013, respectively.

(3) PTR represents the British thermal unit 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 1.1 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.

(5) Current and long-term volumes include approximately 61.6 Bcf and 1.4 Bcf, respectively, 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.

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 presented (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at September 30, 2011	Portfolio Fair Value at October 18, 2011
FV assuming no change in underlying commodity prices	*Asset*	$ 8.9	$ 14.7
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(0.4)	5.2
FV assuming 10% decrease in underlying commodity prices	*Asset*	18.3	24.2

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 presented (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at September 30, 2011	Portfolio Fair Value at October 18, 2011
FV assuming no change in underlying commodity prices	*Liability*	$ (34.9)	$ (71.8)
FV assuming 10% increase in underlying commodity prices	*Liability*	(71.9)	(111.6)
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	2.0	(32.0)

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

Scenario	Resulting Classification	Portfolio Fair Value at September 30, 2011	Portfolio Fair Value at October 18, 2011
FV assuming no change in underlying commodity prices	*Asset*	$ 6.6	$ 2.8
FV assuming 10% increase in underlying commodity prices	*Asset*	3.7	1.3
FV assuming 10% decrease in underlying commodity prices	*Asset*	9.5	4.4

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 CEO (our principal executive officer) and our general partner's chief financial officer (our principal financial officer) (the "CFO"), of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based on this evaluation, as of the end of the period covered by this quarterly report, the CEO and CFO concluded:

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

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

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the third quarter of 2011, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings*.**

For information regarding our litigation matters, see Note 15, "Commitments and Contingencies – Litigation," 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 2010 Form 10-K, in addition to other information in such annual report. The risk factors set forth in our 2010 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.***

As of September 30, 2011, we and our affiliates could repurchase up to 618,400 additional common units under the December 1998 Common Unit Repurchase Program. We did not repurchase any of our common units in connection with this program during the nine months ended September 30, 2011.

The following table summarizes our repurchase activity during 2011 in connection with other arrangements:

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 2011 (1)	91,126	$ 43.00	--	--
May 2011 (2)	135,475	$ 41.63	--	--
August 2011 (3)	14,831	$ 38.62	--	--

(1) Of the 336,227 restricted common units that vested in February 2011 and converted to common units, 91,126 units were sold back to us by employees to cover related withholding tax requirements.
(2) Of the 492,318 restricted common units that vested in May 2011 and converted to common units, 135,475 units were sold back to us by employees to cover related withholding tax requirements.
(3) Of the 57,963 restricted common units that vested in August 2011 and converted to common units, 14,831 units were sold back to us by employees to cover related withholding tax requirements.

Item 3. ***Defaults Upon Senior Securities.***

None.

Item 4. ***(Removed and Reserved).***

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 4.1 to Form S-1/A Registration Statement, Reg. No. 333-52537, filed July 21, 1998).
4.2	Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.3	First Supplemental Indenture, dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration 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	Global Note representing $350.0 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.26	Global Note representing $499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 10-K filed March 31, 2003).
4.27	Global Notes representing $450.0 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.28	Global Note representing $500.0 million principal amount of 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).
4.29	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).
4.30	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).

4.31	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).
4.32	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).
4.33	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.34	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).
4.35	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).
4.36	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).
4.37	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).
4.38	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).
4.39	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).
4.40	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).
4.41	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).
4.42	Form of Global Note representing $182.6 million principal amount of 6.125% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 28, 2009).
4.43	Form of Global Note representing $237.6 million principal amount of 5.90% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 28, 2009).
4.44	Form of Global Note representing $349.7 million principal amount of 6.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 8-K filed October 28, 2009).
4.45	Form of Global Note representing $399.6 million principal amount of 7.55% Senior Notes due 2038 with attached Guarantee (incorporated by reference to Exhibit 4.7 to Form 8-K filed October 28, 2009).
4.46	Form of Global Note representing $285.8 million principal amount of 7.000% Junior Subordinated Notes due 2067 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 8-K filed October 28, 2009).
4.47	Form of Global Note representing $400.0 million principal amount of 3.70% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.48	Form of Global Note representing $1.0 billion principal amount of 5.20% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.49	Form of Global Note representing $600.0 million principal amount of 6.45% Senior Notes due 2040 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).

4.50	Form of Global Note representing $750.0 million principal amount of 3.20% Senior Notes due 2016 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).
4.51	Form of Global Note representing $750.0 million principal amount of 5.95% Senior Notes due 2041 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).
4.52	Form of Global Note representing $650.0 million principal amount of 4.05% Senior Notes due 2022 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 24, 2011).
4.53	Form of Global Note representing $600.0 million principal amount of 5.70% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 24, 2011).
4.54	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).
4.55	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).
4.56	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).
4.57	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).
4.58	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).
4.59	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).
4.60	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).
4.61	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).
4.62	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).
4.63	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).

4.64	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).
4.65	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).
4.66	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).
4.67	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).
4.68	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).
4.69	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).
4.70	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).
4.71	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).
4.72	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).
4.73	Full Release of Guarantee, dated as of November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.70 to Form 10-K filed on March 1, 2010).
10.1	Revolving Credit Agreement, dated as of September 7, 2011, among Enterprise Products Operating LLC, Canadian Enterprise Gas Products, Ltd, the Lenders party thereto, Wells Fargo Bank National Association, as Administrative Agent, The Royal Bank of Scotland PLC, Mizuho Corporate Bank, Ltd. and The Bank of Nova Scotia, as Co-syndication Agents and JPMorgan Chase Bank, N.A. and Barclays Bank PLC, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 8, 2011).

10.2	Guaranty Agreement, dated as of September 7, 2011, by and among Enterprise Products Partners L.P. and Enterprise Products Operating LLC in favor of Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed September 8, 2011).
10.3	Sixth Amended and Restated Administrative Services Agreement, dated as of September 7, 2011, by and among Enterprise Products Company, EPCO Holdings, Inc., Enterprise Products Holdings LLC, Enterprise Products Partners L.P., Enterprise Products OLPGP, Inc., Enterprise Products Operating LLC, the TEPPCO Parties named therein, Enterprise ETE LLC and the DEP Parties named therein (incorporated by reference to Exhibit 10.3 to Form 8-K filed September 8, 2011).
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the September 30, 2011 quarterly report on Form 10-Q.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P. for the September 30, 2011 quarterly report on Form 10-Q.
32.1#	Section 1350 certification of Michael A. Creel for the September 30, 2011 quarterly report on Form 10-Q.
32.2#	Section 1350 certification of W. Randall Fowler for the September 30, 2011 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.

\# Filed with this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)

By: Enterprise Products Holdings LLC, as General Partner

Date:	November 9, 2011	By:	/s/ Michael J. Knesek
		Name:	Michael J. Knesek
		Title:	Senior Vice President, Controller and Principal Accounting Officer of the General Partner

EXHIBIT 31.1

CERTIFICATIONS

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, 2011

/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

CERTIFICATIONS

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, 2011

/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, 2011 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, 2011

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, 2011 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, 2011