ENTERPRISE PRODUCTS PARTNERS L P
Form 10-Q
November 10, 2008

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

FORM 10-Q

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

For the quarterly period ended September 30, 2008

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, 10th Floor
Houston, Texas 77002
(Address of Principal Executive Offices, Including Zip Code)

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

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

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

Large accelerated filer þ

Accelerated filer o

Non-accelerated filer o (Do not check if a smaller reporting company)

Smaller reporting company o

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

Yes o No þ

There were 437,850,289 common units, including 2,239,613 restricted common units, of Enterprise Products Partners L.P. outstanding at November 3, 2008. These common units trade on the New York Stock Exchange under the ticker symbol "EPD."

ENTERPRISE PRODUCTS PARTNERS L.P.
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Item 1. Financial Statements.

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

ASSETS	September 30, 2008	December 31, 2007
Current assets:		
Cash and cash equivalents	$ 55,403	$ 39,722
Restricted cash	183,221	53,144
Accounts and notes receivable – trade, net of allowance for doubtful accounts of $15,781 at September 30, 2008 and $21,659 at December 31, 2007	1,840,584	1,930,762
Accounts receivable – related parties	88,871	79,782
Inventories	653,783	354,282
Prepaid and other current assets	161,233	80,193
Total current assets	2,983,095	2,537,885
Property, plant and equipment, net	12,693,619	11,587,264
Investments in and advances to unconsolidated affiliates	917,193	858,339
Intangible assets, net of accumulated amortization of $408,304 at September 30, 2008 and $341,494 at December 31, 2007	866,313	917,000
Goodwill	616,996	591,652
Deferred tax asset	2,927	3,522
Other assets, including restricted cash of $17,871 at December 31, 2007	69,067	112,345
Total assets	$ 18,149,210	$ 16,608,007
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable – trade	$ 245,629	$ 324,999
Accounts payable – related parties	75,635	24,432
Accrued product payables	2,241,336	2,227,489
Accrued expenses	75,156	47,756
Accrued interest	101,962	130,971
Other current liabilities	430,377	289,036
Total current liabilities	3,170,095	3,044,683
Long-term debt: (see Note 10)		
Senior debt obligations – principal	7,184,201	5,646,500
Junior subordinated notes – principal	1,250,000	1,250,000
Other	23,994	9,645
Total long-term debt	8,458,195	6,906,145
Deferred tax liabilities	23,161	21,364
Other long-term liabilities	66,102	73,748
Minority interest	412,911	430,418
Commitments and contingencies		
Partners' equity: (see Note 11)		

Limited partners		
Common units (435,610,676 units outstanding at September 30, 2008		
and 433,608,763 units outstanding at December 31, 2007)	5,990,461	5,976,947
Restricted common units (2,239,613 units outstanding at September 30, 2008		
and 1,688,540 units outstanding at December 31, 2007)	23,869	15,948
General partner	122,639	122,297
Accumulated other comprehensive income (loss)	(118,223)	16,457
Total partners' equity	6,018,746	6,131,649
Total liabilities and partners' equity	$ 18,149,210	$ 16,608,007

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Revenues:				
Third parties	$ 5,997,743	$ 3,933,157	$ 17,498,445	$ 11,268,342
Related parties	300,159	178,839	823,607	379,314
Total revenues	6,297,902	4,111,996	18,322,052	11,647,656
Costs and expenses:				
Operating costs and expenses:				
Third parties	5,806,735	3,815,087	16,766,003	10,730,670
Related parties	165,207	81,324	477,067	250,892
Total operating costs and expenses	5,971,942	3,896,411	17,243,070	10,981,562
General and administrative costs:				
Third parties	8,354	7,211	22,307	21,414
Related parties	13,366	11,504	44,594	45,292
Total general and administrative costs	21,720	18,715	66,901	66,706
Total costs and expenses	5,993,662	3,915,126	17,309,971	11,048,268
Equity in earnings of unconsolidated affiliates	14,876	13,960	48,037	13,928
Operating income	319,116	210,830	1,060,118	613,316
Other income (expense):				
Interest expense	(102,657)	(85,075)	(290,412)	(219,708)
Interest income	2,095	2,300	4,708	6,743
Other, net	(917)	(594)	(1,968)	(362)
Total other expense, net	(101,479)	(83,369)	(287,672)	(213,327)
Income before provision for income taxes and minority interest	217,637	127,461	772,446	399,989
Provision for income taxes	(6,610)	(2,073)	(17,193)	(9,001)
Income before minority interest	211,027	125,388	755,253	390,988
Minority interest	(7,946)	(7,782)	(29,293)	(19,183)
Net income	$ 203,081	$ 117,606	$ 725,960	$ 371,805
Net income allocation: (see Note 11)				
Limited partners' interest in net income	$ 167,625	$ 88,408	$ 620,494	$ 286,984
General partner's interest in net income	$ 35,456	$ 29,198	$ 105,466	$ 84,821
Earning per unit: (see Note 14)				
Basic and diluted income per unit	$ 0.38	$ 0.20	$ 1.42	$ 0.66

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Net income	$ 203,081	$ 117,606	$ 725,960	$ 371,805
Other comprehensive income (loss):				
Cash flow hedges: (see Note 4)				
Foreign currency hedge gains (losses)	--	2,879	(1,308)	2,879
Net commodity financial instrument losses	(215,540)	(22,292)	(108,294)	(21,446)
Net interest rate financial instrument gains (losses)	(242)	373	(21,283)	40,637
Less: Amortization of cash flow financing hedges	(800)	(1,096)	(3,983)	(3,365)
Total cash flow hedges	(216,582)	(20,136)	(134,868)	18,705
Foreign currency translation adjustment	377	1,832	452	2,381
Change in funded status of Dixie benefit plans, net of tax	--	--	(264)	--
Total other comprehensive income (loss)	(216,205)	(18,304)	(134,680)	21,086
Comprehensive income (loss)	$ (13,124)	$ 99,302	$ 591,280	$ 392,891

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Nine Months Ended September 30, 2008	2007
Operating activities:		
Net income	$ 725,960	$ 371,805
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion in operating costs and expenses	408,601	374,522
Depreciation and amortization in general and administrative costs	8,137	7,129
Amortization in interest expense	(3,161)	432
Equity in earnings of unconsolidated affiliates	(48,037)	(13,928)
Distributions received from unconsolidated affiliates	69,852	52,343
Operating lease expense paid by EPCO, Inc.	1,579	1,579
Minority interest	29,293	19,183
Loss (gain) from asset sales and related transactions	(1,710)	5,445
Deferred income tax expense	5,580	5,542
Changes in fair market value of financial instruments	5,461	3,511
Effect of pension settlement recognition	(114)	--
Net effect of changes in operating accounts (see Note 17)	(228,397)	110,272
Net cash flows provided by operating activities	973,044	937,835
Investing activities:		
Capital expenditures	(1,485,654)	(1,684,455)
Contributions in aid of construction costs	21,215	52,462
Proceeds from asset sales and related transactions	1,685	1,933
Increase in restricted cash	(112,207)	(79,535)
Cash used for business combinations	(57,090)	(785)
Acquisition of intangible assets	(5,126)	--
Investments in unconsolidated affiliates	(35,307)	(318,491)
Advances to unconsolidated affiliates	(36,719)	(10,624)
Cash used in investing activities	(1,709,203)	(2,039,495)
Financing activities:		
Borrowings under debt agreements	6,360,387	4,926,858
Repayments of debt	(4,824,000)	(3,459,881)
Debt issuance costs	(8,793)	(15,281)
Distributions paid to partners	(770,848)	(711,739)
Distributions paid to minority interests	(39,196)	(20,485)
Proceeds from initial public offering of Duncan Energy Partners in minority interest	--	290,466
Other contributions from minority interests	28	12,506
Monetization of interest rate hedging financial instruments (see Note 4)	(22,144)	48,895
Repurchase of option awards	--	(1,568)
Acquisition of treasury units	(795)	--
Net proceeds from issuance of common units	57,181	52,804
Cash provided by financing activities	751,820	1,122,575
Effect of exchange rate changes on cash flows	20	347

Net change in cash and cash equivalents	15,661	20,915
Cash and cash equivalents, January 1	39,722	22,619
Cash and cash equivalents, September 30	$ 55,403	$ 43,881

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY
(See Note 11 for Unit History, Detail of Changes in Limited Partners' Equity and Accumulated Other Comprehensive Income (Loss))
(Dollars in thousands)

	Limited Partners	General Partner	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2007	$ 5,992,895	$ 122,297	$ 16,457	$ 6,131,649
Net income	620,494	105,466	--	725,960
Operating leases paid by EPCO, Inc.	1,548	31	--	1,579
Cash distributions to partners	(663,946)	(106,352)	--	(770,298)
Unit option reimbursements to EPCO, Inc.	(550)	--	--	(550)
Non-cash distributions	(5,006)	(100)	--	(5,106)
Acquisition of treasury units	(779)	(16)	--	(795)
Net proceeds from issuance of common units	55,363	1,130	--	56,493
Proceeds from exercise of unit options	680	8	--	688
Amortization of unit-based awards	13,631	175	--	13,806
Change in funded status of Dixie benefit plans, net of tax	--	--	(264)	(264)
Foreign currency translation adjustment	--	--	452	452
Cash flow hedges	--	--	(134,868)	(134,868)
Balance, September 30, 2008	$ 6,014,330	$ 122,639	$ (118,223)	$ 6,018,746

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

Except 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 thousands of dollars.

Note 1. Partnership Organization

Partnership Organization

Enterprise Products Partners L.P. is 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." Unless the context requires otherwise, references to "we," "us," "our" or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO, Inc. ("EPCO"). We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating LLC ("EPO"). We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our general partner, referred to as "EPGP"). EPGP is owned 100% by Enterprise GP Holdings L.P. ("Enterprise GP Holdings"), a publicly traded affiliate, the units of which are listed on the NYSE under the ticker symbol "EPE." The general partner of Enterprise GP Holdings is EPE Holdings, LLC ("EPE Holdings"), a wholly owned subsidiary of Dan Duncan LLC, the membership interests of which are owned by Dan L. Duncan. We, EPGP, Enterprise GP Holdings, EPE Holdings and Dan Duncan LLC are affiliates and under common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

References to "TEPPCO" mean TEPPCO Partners, L.P., a publicly traded affiliate, the common units of which are listed on the NYSE under the ticker symbol "TPP." References to "TEPPCO GP" refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by Enterprise GP Holdings.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries. References to "LE GP" mean LE GP, LLC, which is the general partner of Energy Transfer Equity. On May 7, 2007, Enterprise GP Holdings acquired non-controlling interests in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

References to "Employee Partnerships" mean EPE Unit L.P. ("EPE Unit I"), EPE Unit II, L.P. ("EPE Unit II"), EPE Unit III, L.P. ("EPE Unit III") and Enterprise Unit L.P. ("Enterprise Unit"), collectively, which are private company affiliates of EPCO.

On February 5, 2007, a consolidated subsidiary of ours, Duncan Energy Partners L.P. ("Duncan Energy Partners"), completed an initial public offering of its common units (see Note 13). Duncan Energy Partners owns equity interests in certain of our midstream energy businesses. References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own and reflect its operations in our business segments. We control Duncan Energy Partners through our ownership of its general partner. Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners reflects our historical carrying basis in each of the subsidiaries contributed to

Duncan Energy Partners. Public ownership of Duncan Energy Partners' net assets and earnings are presented as a component of minority interest in our condensed consolidated financial statements. The borrowings of Duncan Energy Partners are presented as

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part of our consolidated debt; however, neither Enterprise Products Partners L.P. nor EPO have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

Basis of Presentation

Our results of operations for the three and nine months ended September 30, 2008 are not necessarily indicative of results expected for the full year.

Essentially all of our assets, liabilities, revenues and expenses are recorded at EPO's level in our consolidated financial statements. Enterprise Products Partners L.P. acts as guarantor of certain of EPO's debt obligations. See Note 18 for condensed consolidated financial information of EPO.

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 to make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP") have been condensed or omitted pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). These Unaudited Condensed Consolidated Financial Statements and notes thereto should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2007 (Commission File No. 1-14323).

Note 2. General Accounting Policies and Related Matters

Consolidation Policy

Our financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling financial or equity interest, after the elimination of intercompany accounts and transactions. We evaluate our financial interests in companies to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own.

If an investee is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3% and 50% and we exercise significant influence over the investee's operating and financial policies. For all other types of investments, we apply the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the investee's operating and financial policies. In consolidation we eliminate our proportionate share of profits and losses from transactions with our equity method unconsolidated affiliates to the extent such amounts are material and remain on our balance sheet (or those of our equity method investees) in inventory or similar accounts.

If our ownership interest in an investee does not provide us with either control or significant influence over the investee, we account for the investment using the cost method.

Dixie Employee Benefit Plans

Dixie Pipeline Company ("Dixie"), a consolidated subsidiary of EPO, directly employs the personnel that operate its pipeline system. Certain of these employees are eligible to participate in Dixie's defined contribution plan and pension and postretirement benefit plans.

Defined Contribution Plan. Dixie contributed $0.1 million to its company-sponsored defined contribution plan during each of the three month periods ended September 30, 2008 and 2007. During each of the nine month periods ended September 30, 2008 and 2007, Dixie contributed $0.2 million to its company-sponsored defined contribution plan.

Pension and Postretirement Benefit Plans. Dixie's net pension benefit costs were $0.1 million for each of the three month periods ended September 30, 2008 and 2007. For each of the nine month periods ended September 30, 2008 and 2007, Dixie's net pension benefit costs were $0.4 million. Dixie's net postretirement benefit costs were $0.1 million for each of the three month periods ended September 30, 2008 and 2007. For each of the nine month periods ended September 30, 2008 and 2007, Dixie's net postretirement benefit costs were $0.3 million. During the remainder of 2008, Dixie expects to contribute approximately $0.5 million to its pension plan and approximately $0.1 million to its postretirement benefit plan.

Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management's best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At September 30, 2008, none of our estimated environmental remediation liabilities are discounted to present value since the ultimate amount and timing of cash payments for such liabilities are not readily determinable. Expenditures to mitigate or prevent future environmental contamination are capitalized.

At September 30, 2008 and December 31, 2007, our accrued liabilities for environmental remediation projects totaled $21.2 million and $26.5 million, respectively. These amounts were derived from a range of reasonable estimates based upon studies and site surveys. Unanticipated changes in circumstances and/or legal requirements could result in expenses being incurred in future periods in addition to an increase in actual cash required to remediate contamination for which we are responsible.

Estimates

Preparing our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect amounts presented in the financial statements (i.e. assets, liabilities, revenue and expenses) and disclosures about contingent assets and liabilities. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

We revised the remaining useful lives of certain assets, most notably the assets that constitute our Texas Intrastate System, effective January 1, 2008. This revision adjusted the remaining useful life of such assets to incorporate recent data showing that proved natural gas reserves supporting throughput and processing volumes for these assets have changed since our original determination made in September 2004. These revisions will prospectively reduce our depreciation expense on assets having carrying values totaling $2.72 billion at January 1, 2008. For additional information regarding this change in estimate, see Note 6.

Minority Interest

As presented in our Unaudited Condensed Consolidated Balance Sheets, minority interest represents third-party and affiliate ownership interests in the net assets of our consolidated subsidiaries. For financial reporting purposes, the assets and liabilities of our controlled subsidiaries, including Duncan Energy Partners, are consolidated with those of our own, with any third-party or affiliate ownership interests in such amounts presented as minority interest.

At September 30, 2008 and December 31, 2007, minority interest includes $281.9 million and $288.6 million, respectively, attributable to third party owners of Duncan Energy Partners. Minority interest expense for the three months ended September 30, 2008 and 2007 includes $2.7 million and $3.2

million, respectively, attributable to third party owners of Duncan Energy Partners. For the nine months ended September 30, 2008 and 2007 minority interest expense attributable to third party owners of Duncan Energy Partners was $11.9 million and $9.4 million, respectively. The remaining minority interest expense amounts for 2008 and 2007 are attributable to our other consolidated affiliates.

Contributions from minority interests for the nine months ended September 30, 2007 includes approximately $291.0 million received from third parties in connection with the initial public offering of Duncan Energy Partners in February 2007.

Recent Accounting Developments

The following information summarizes recently issued accounting guidance since those reported in our Annual Report on Form 10-K for the year ended December 31, 2007 that will or may affect our future financial statements.

Statement of Financial Accounting Standards ("SFAS") No. 161, Disclosures about Derivative Instruments and Hedging Activities – An Amendment of FASB Statement No. 133. Issued in March 2008, SFAS 161 changes the disclosure requirements for financial instruments and hedging activities with the intent to provide users of financial statements with an enhanced understanding of (i) how and why an entity uses financial instruments, (ii) how financial instruments and related hedged items are accounted for under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, and its related interpretations and (iii) how financial instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 requires qualitative disclosures about objectives and strategies for using financial instruments, quantitative disclosures about fair value amounts of and gains and losses on financial instruments and disclosures about credit-risk-related contingent features in financial instrument agreements. This statement has the same scope as SFAS 133, and accordingly applies to all entities. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. SFAS 161 only affects disclosure requirements; therefore, our adoption of this statement effective January 1, 2009 will not impact our financial position, results of operations or cash flows.

Emerging Issues Task Force ("EITF") 07-4, Application of the Two Class Method Under FASB Statement No. 128, Earnings Per Share, to Master Limited Partnerships ("MLP"). EITF 07-4 was issued during the first quarter of 2008 and prescribes the manner in which a MLP should allocate and present earnings per unit using the two-class method set forth in SFAS 128, Earnings Per Share. Under the two-class method, current period earnings are allocated to the general partner (including earnings attributable to any embedded incentive distribution rights) and limited partners according to the distribution formula for available cash set forth in the MLP's partnership agreement. EITF 07-4 is effective for us on January 1, 2009. We do not believe that EITF 07-4 will have a material impact on our earnings per unit computations and disclosures.

FASB Staff Position ("FSP") No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities. FSP EITF 03-6-1 was issued in June 2008. FSP EITF 03-6-1 clarifies that unvested share-based payment awards constitute participating securities, if such awards include nonforfeitable rights to dividends or dividend equivalents. Consequently, awards that are deemed to be participating securities must be allocated earnings in the computation of earnings per share under the two-class method. FSP EITF 03-6-1 is effective for us on January 1, 2009. We do not believe that FSP EITF 03-6-1 will have a material impact on our earnings per unit computations and disclosures.

FSP No. FAS 157-2, Effective Date of FASB Statement No. 157. FSP 157-2 defers the effective date of SFAS 157, Fair Value Measurements, to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years, for all nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). As allowed under FSP 157-2, we have not applied the provisions of SFAS 157 to our nonfinancial assets and liabilities measured at fair value, which include certain assets and liabilities acquired in business combinations. On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. See Note 4 for these fair value disclosures. We do not expect any immediate impact from adoption of the remaining portions of SFAS 157 on January 1, 2009.

In light of current market conditions, the FASB has issued additional clarifying guidance regarding the implementation of SFAS 157, particularly with respect to financial assets that do not trade in active markets such as investments in joint ventures. This clarifying guidance did not result in a change in our accounting, reporting or impairment testing for such investments. We continue to monitor developments at the FASB and SEC for new matters and guidance that may affect our valuation processes.

FSP No. FAS 142-3, Determination of the Useful Life of Intangible Assets. In April 2008, the FASB issued FSP 142-3, which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful lives of recognized intangible assets under SFAS 142, Goodwill and Other Intangible Assets. This change is intended to improve consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of such assets under SFAS 141(R) and other accounting guidance. The requirement for determining useful lives must be applied prospectively to intangible assets acquired after January 1, 2009 and the disclosure requirements must be applied prospectively to all intangible assets recognized as of, and subsequent to, January 1, 2009. We will adopt the provisions of FSP 142-3 on January 1, 2009.

Restricted Cash

Restricted cash represents amounts held in connection with our commodity financial instruments portfolio and New York Mercantile Exchange ("NYMEX") physical natural gas purchases. Additional cash may be restricted to maintain our positions as commodity prices fluctuate or deposit requirements change. At December 31, 2007, restricted cash also included amounts held by a third party trustee charged with disbursing proceeds from our Petal GO Zone bond offering. As of June 30, 2008, all proceeds from the Petal GO Zone bonds had been released by the trustee to fund construction costs associated with the expansion of our Petal, Mississippi storage facility. The following table presents the components of our restricted cash balances at the periods indicated:

	September 30, 2008	December 31, 2007
Amounts held in brokerage accounts related to		
commodity hedging activities and physical natural gas purchases	$ 183,221	$ 53,144
Proceeds from Petal GO Zone bonds reserved for construction costs	--	17,871
Total restricted cash	$ 183,221	$ 71,015

Note 3. Accounting for Unit-Based Awards

We account for unit-based awards in accordance with SFAS 123(R), Share-Based Payment. SFAS 123(R) requires us to recognize compensation expense related to unit-based awards based on the fair value of the award at grant date. The fair value of restricted unit awards is based on the market price of the underlying common units on the date of grant. The fair value of other unit-based awards is estimated using the Black-Scholes option pricing model. The fair value of an equity-classified award (such as a restricted unit award) is amortized to earnings on a straight-line basis over the requisite service or vesting period. Compensation expense for liability-classified awards (such as unit appreciation rights ("UARs")) is recognized over the requisite service or vesting period of an award based on the fair value of the award remeasured at each reporting period. Liability-type awards are settled in cash upon vesting.

The following table summarizes our unit-based compensation expense amounts by plan during each of the periods indicated:

	For the Three Months Ended September 30, 2008	2007	For the Nine Months Ended September 30, 2008	2007
EPCO 1998 Long-Term Incentive Plan ("1998 Plan")				
Unit options	$ 116	$ 139	$ 329	$ 4,248
Restricted units	2,569	1,981	6,121	5,639
Total 1998 Plan (1)	2,685	2,120	6,450	9,887
Enterprise Products 2008 Long-Term Incentive Plan ("2008 LTIP")				
Unit options	36	--	50	--
Total 2008 LTIP	36	--	50	--
Employee Partnerships	1,540	1,364	4,099	2,542
DEP GP Unit Appreciation Rights	(1)	23	5	58
Total consolidated expense	$ 4,260	$ 3,507	$ 10,604	$ 12,487

(1) Amounts presented for the nine months ended September 30, 2007 include $4.6 million associated with the resignation of our former Chief Executive Officer.

1998 Plan

The 1998 Plan provides for the issuance of up to 7,000,000 of our common units. After giving effect to outstanding option awards at September 30, 2008 and the issuance and forfeiture of restricted unit awards through September 30, 2008, a total of 771,546 additional common units could be issued under the 1998 Plan.

Unit option awards. Under the 1998 Plan, non-qualified incentive options to purchase a fixed number of our common units may be granted to key employees of EPCO who perform management, administrative or operational functions for us. The following table presents unit option activity under the 1998 Plan for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Outstanding at December 31, 2007 (2)	2,315,000	$ 26.18		
Exercised	(61,500)	$ 20.38		
Forfeited or terminated	(85,000)	$ 26.72		
Outstanding at September 30, 2008	2,168,500	$ 26.32	5.44	$ 2,356
Options exercisable at September 30, 2008	548,500	$ 21.47	4.33	$ 2,356

(1) Aggregate intrinsic value reflects fully vested unit options at September 30, 2008.
(2) During 2008, we amended the terms of certain of our outstanding unit options. In general, the expiration dates of these awards were modified from May and August 2017 to December 2012.

The total intrinsic value of unit options exercised during the three and nine months ended September 30, 2008 was $0.1 million and $0.6 million, respectively. At September 30, 2008, there was an estimated $1.9 million of total unrecognized compensation cost related to nonvested unit options granted under the 1998 Plan. We expect to recognize our share of this cost over a weighted-average period of 2.4 years in accordance with the EPCO administrative services agreement (the "ASA").

During the nine months ended September 30, 2008 and 2007, we received cash of $0.7 million and $7.7 million, respectively, from the exercise of unit options. Conversely, our option-related reimbursements to EPCO were $0.6 million and $2.9 million, respectively.

Restricted unit awards. Under the 1998 Plan, we may also issue restricted common units to key employees of EPCO and directors of our general partner. The following table summarizes information regarding our restricted common units for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted units at December 31, 2007	1,688,540	
Granted (2)	750,900	$ 25.30
Forfeited	(84,677)	$ 26.83
Vested	(115,150)	$ 22.83
Restricted units at September 30, 2008	2,239,613	

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued. The weighted-average grant date fair value per unit for forfeited and vested awards is determined before an allowance for forfeitures.
(2) Aggregate grant date fair value of restricted common unit awards issued during 2008 was $19.0 million based on a grant date market price of our common units ranging from $28.21 to $32.31 per unit and an estimated forfeiture rate of 17.0%.

The total fair value of our restricted unit awards that vested during the three and nine months ended September 30, 2008 was $1.2 million and $2.6 million, respectively. As of September 30, 2008, there was $34.6 million of total unrecognized compensation cost related to restricted common units. We will recognize our share of such costs in accordance with the EPCO ASA. At September 30, 2008, these costs are expected to be recognized over a weighted-average period of 2.4 years.

Phantom unit awards. The 1998 Plan also provides for the issuance of phantom unit awards. These liability awards are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at redemption dates in each award. No phantom unit awards have been issued to date under the 1998 Plan.

2008 LTIP

On January 29, 2008, our unitholders approved the 2008 LTIP, which 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 LTIP may be granted in the form of unit options, restricted units, phantom units, UARs and distribution equivalent rights. The 2008 LTIP is administered by EPGP's Audit, Conflicts and Governance ("ACG") Committee. The 2008 LTIP provides for the issuance of up to 10,000,000 of our common units. After giving effect to option awards outstanding at September 30, 2008, a total of 9,205,000 additional common units could be issued under the 2008 LTIP.

The 2008 LTIP may be amended or terminated at any time by the Board of Directors of EPCO or EPGP's ACG Committee; however, the rules of the NYSE require that any material amendment, such as a significant increase in the number of common units available under the plan or a change in the types of awards available under the plan, would require the approval of our unitholders. The ACG Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in, awards under the plan in specified circumstances. The 2008 LTIP is effective until the earlier of January 29, 2018 or the time which all available units under the incentive plan have been delivered to participants or the time of termination of the plan by EPCO or EPGP's ACG Committee.

Unit option awards. The exercise price of unit options awarded to participants is determined by the ACG Committee (at its discretion) at the date of grant and may be no less than the fair market value of our common units at the date of grant. The following table presents unit option activity under the 2008 LTIP for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)
Outstanding at January 29, 2008	--		
Granted (1)	795,000	$ 30.93	
Outstanding at September 30, 2008	795,000	$ 30.93	5.25

(1)   Aggregate grant date fair value of these unit options issued during 2008 was $1.6 million based on the following assumptions: (i) a grant date market price of our common units of $30.93 per unit; (ii) expected life of options of 4.7 years; (iii) risk-free interest rate of 3.3%; (iv) expected distribution yield on our common units of 7.0%; (v) expected unit price volatility on our common units of 19.8%; and (vi) an estimated forfeiture rate of 17.0%.

At September 30, 2008, there was an estimated $1.4 million of total unrecognized compensation cost related to nonvested unit options granted under the 2008 LTIP. We expect to recognize our share of this cost over a remaining period of 3.6 years in accordance with the EPCO ASA.

Employee Partnerships

EPCO formed the Employee Partnerships to serve as an incentive arrangement for key employees of EPCO by providing them a “profits interest” in the Employee Partnerships. Currently, there are four Employee Partnerships: EPE Unit I, EPE Unit II, EPE Unit III and Enterprise Unit. EPE Unit I was formed in August 2005 in connection with Enterprise GP Holdings’ initial public offering, EPE Unit II was formed in December 2006, EPE Unit III was formed in May 2007 and Enterprise Unit was formed in February 2008. For a detailed description of EPE Unit I, EPE Unit II and EPE Unit III, see our Annual Report on Form 10-K for the year ended December 31, 2007.

In July 2008, each of EPE Unit I, EPE Unit II and EPE Unit III entered into a second amendment to its respective agreement of limited partnership (“Second Amendment”). The Second Amendments for EPE Unit I and EPE Unit II provide for the reduction of the rate at which the Class A Limited Partner, Duncan Family Interests, Inc., earns a preferred return on its investment in EPE Unit I and EPE Unit II (“Class A Preference Return Rate”). The Class A Preference Return Rate in each of these two limited partnership agreements was reduced from 6.25% to a floating preference rate to be determined by EPCO (in its sole discretion) that will be between 4.50% and 5.725% per annum. The Second Amendment for EPE Unit I and EPE Unit II also provides that the liquidation date of these partnerships be extended to November 2012 and February 2014, respectively. The Second Amendment for EPE Unit III extends the liquidation date of EPE Unit III to May 2014. Collectively, the Second Amendment to these partnership agreements resulted in an aggregate $18.2 million increase in non-cash compensation costs attributable to the profits interest awards in EPE Unit I, EPE Unit II and EPE Unit III.

As of September 30, 2008, there was $43.4 million of total unrecognized compensation cost related to the four Employee Partnerships. We will recognize our share of these costs in accordance with the EPCO ASA over a weighted-average period of 5.2 years.

Enterprise Unit.   On February 20, 2008, EPCO formed Enterprise Unit to serve as an incentive arrangement for certain employees of EPCO through a "profits interest" in Enterprise Unit. On that date, EPCO Holdings, Inc. ("EPCO Holdings") agreed to contribute $18.0 million in the aggregate (the "Initial Contribution") to Enterprise Unit and was admitted as the Class A limited partner. Certain key employees of EPCO, including our Chief Executive Officer and Chief Financial Officer, were issued Class B limited partner interests and admitted as Class B limited partners of Enterprise Unit without any capital contributions. EPCO Holdings made capital contributions to Enterprise Unit in addition to its Initial

Contribution and may make additional contributions, although it has no legal obligation to do so. As of September 30, 2008, EPCO Holdings has contributed a total of $51.5 million to Enterprise Unit.

As with the awards granted in connection with the other Employee Partnerships, these awards are designed to provide additional long-term incentive compensation for certain employees. The profits interest awards (or Class B limited partner interests) in Enterprise Unit entitle the holder to participate in the appreciation in value of Enterprise GP Holdings' units and our common units and are subject to early vesting or forfeiture upon the occurrence of certain events.

An allocated portion of the fair value of these equity awards will be charged to us under the EPCO ASA as a non-cash expense. We will not reimburse EPCO, Enterprise Unit or any of their affiliates or partners, through the ASA or otherwise, in cash for any expenses related to Enterprise Unit, including the Initial Contribution by EPCO Holdings.

The Class B limited partner interests in Enterprise Unit that are owned by EPCO employees are subject to forfeiture if the participating employee's employment with EPCO and its affiliates is terminated prior to February 20, 2014, with customary exceptions for death, disability and certain retirements that will result in early vesting. The risk of forfeiture associated with the Class B limited partner interests in Enterprise Unit will also lapse (i.e. the interests will become vested) upon certain change of control events.

Unless otherwise agreed to by EPCO, EPCO Holdings and a majority in interest of the Class B limited partners of Enterprise Unit, Enterprise Unit will terminate at the earlier of February 20, 2014 (six years from the date of the agreement) or a change in control of us or Enterprise GP Holdings. Enterprise Unit has the following material terms regarding its quarterly cash distribution to partners:

§ Distributions of cash flow – Each quarter, 100% of the cash distributions received by Enterprise Unit from Enterprise GP Holdings and us will be distributed to the Class A limited partner until EPCO Holdings has received an amount equal to the Class A preferred return (as defined below), and any remaining distributions received by Enterprise Unit will be distributed to the Class B limited partners. The Class A preferred return equals the Class A capital base (as defined below) multiplied by 5.0% per annum. The Class A limited partner's capital base equals the amount of any contributions of cash or cash equivalents made by the Class A limited partner to Enterprise Unit, plus any unpaid Class A preferred return from prior periods, less any distributions made by Enterprise Unit of proceeds from the sale of units owned by Enterprise Unit (as described below).

§ Liquidating Distributions – Upon liquidation of Enterprise Unit, units having a fair market value equal to the Class A limited partner capital base will be distributed to EPCO Holdings, plus any accrued and unpaid Class A preferred return for the quarter in which liquidation occurs. Any remaining units will be distributed to the Class B limited partners.

§ Sale Proceeds – If Enterprise Unit sells any units that it beneficially owns, the sale proceeds will be distributed to the Class A limited partner and the Class B limited partners in the same manner as liquidating distributions described above.

DEP GP UARs

The non-employee directors of DEP GP, the general partner of Duncan Energy Partners, have been granted UARs in the form of letter agreements. These liability awards are not part of any established long-term incentive plan of EPCO, Enterprise GP Holdings, Duncan Energy Partners or us. These UARs entitle each non-employee director to receive a cash payment on the vesting date equal to the excess, if any, of the fair market value of Enterprise GP Holdings' units (determined as of a future vesting date) over the grant date fair value. These UARs are accounted for similarly to liability awards under SFAS 123(R) since they will be settled with cash. At September 30, 2008 and December 31, 2007, we had a total of 90,000 outstanding UARs granted to non-employee directors of DEP GP that cliff vest in 2012. If a director resigns prior to vesting, his UAR awards are forfeited.

Note 4. Financial Instruments

We are exposed to financial market risks, including changes in commodity prices, interest rates and foreign exchange rates. We may use financial instruments (e.g., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the types of risks we attempt to hedge are those related to (i) the variability of future earnings, (ii) fair values of certain debt instruments and (iii) cash flows resulting from changes in applicable interest rates, commodity prices or exchange rates.

We recognize financial instruments as assets and liabilities on our Unaudited Condensed Consolidated Balance Sheets based on fair value. Fair value is generally defined as the amount at which a financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation techniques. We must use considerable judgment, however, in interpreting market data and developing these estimates. Accordingly, our fair value estimates are not necessarily indicative of the amounts that we could realize upon disposition of these instruments. The use of different market assumptions and/or estimation techniques could have a material effect on our estimates of fair value.

Changes in fair value of financial instrument contracts are recognized in earnings in the current period unless specific hedge accounting criteria are met. If the financial instrument meets the criteria of a fair value hedge, gains and losses incurred on the instrument will be recorded in earnings to offset corresponding losses and gains on the hedged item. If the financial instrument meets the criteria of a cash flow hedge, gains and losses incurred on the instrument are recorded in accumulated other comprehensive income. Gains and losses on cash flow hedges are reclassified from accumulated other comprehensive income to earnings when the forecasted transaction occurs or, as appropriate, over the economic life of the hedged item. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

To qualify for hedge accounting, the item to be hedged must expose us to risk and the related hedging instrument must reduce the exposure and meet the formal hedging requirements of SFAS 133, Accounting for Derivative Instruments and Hedging Activities (as amended and interpreted). We formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at its inception and thereafter on a quarterly basis. Any hedge ineffectiveness is immediately recognized in earnings.

We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific hedging criteria. When this occurs, we may enter into a new financial instrument to reestablish the hedge to which the closed instrument relates.

Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed interest rate borrowings under various debt agreements. We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt.

Fair Value Hedges – Interest Rate Swaps. As summarized in the following table, we had five interest rate swap agreements outstanding at September 30, 2008 that were accounted for as fair value hedges.

Hedged Fixed Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Value
Senior Notes C, 6.375% fixed rate, due Feb. 2013	1	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 5.02%	$100.0 million
Senior Notes G, 5.60% fixed rate, due Oct. 2014	4	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 3.63%	$400.0 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

The aggregate fair value of the five interest rate swaps at September 30, 2008 was an asset of $13.2 million, with an offsetting increase in the fair value of the underlying debt. There were eleven interest rate swaps outstanding at December 31, 2007 having an aggregate fair value of $14.8 million (an asset). Interest expense for the three months ended September 30, 2008 and 2007 includes a $1.8 million benefit and a $2.3 million loss, respectively, from interest rate swap agreements. For the nine months ended September 30, 2008 and 2007, interest expense reflects a benefit of $3.2 million and a loss of $6.9 million, respectively, from interest rate swap agreements.

The following table summarizes the termination of our interest rate swaps during 2008 (dollars in millions):

	Notional Value	Cash Gains (1)
Interest rate swap portfolio, December 31, 2007	$ 1,050.0	$ --
First quarter of 2008 terminations	(200.0)	6.3
Second quarter of 2008 terminations	(250.0)	12.0
Third quarter of 2008 terminations (2)	(100.0)	--
Interest rate swap portfolio, September 30, 2008	$ 500.0	$ 18.3

(1) Cash gains resulting from the termination, or monetization, of interest rate swaps will be amortized to earnings as a reduction to interest expense over the remaining life of the underlying debt.
(2) In early October 2008, one counterparty filed for bankruptcy. At September 30, 2008, the fair value of this interest rate swap was $3.4 million and this amount has been fully reserved. Hedge accounting for this swap has been discontinued.

Cash Flow Hedges – Interest Rate Swaps. Duncan Energy Partners had three floating-to-fixed interest rate swap agreements outstanding at September 30, 2008 that were accounted for as cash flow hedges.

Hedged Variable Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Variable to Fixed Rate (1)	Notional Value
Duncan Energy Partners' Revolver, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	3.77% to 4.62%	$175.0 million

(1) Amounts receivable from or payable to the swap counterparties are settled every three months (the "settlement period").

We recognized losses of $0.8 million and $1.6 million from these swap agreements during the three and nine months ended September 30, 2008, respectively. The aggregate fair values of these interest rate swaps at September 30, 2008 and December 31, 2007 were liabilities of $4.3 million and $3.8 million, respectively. As cash flow hedges, any increase or decrease in fair value of the financial instrument (to the extent effective) would be recorded as other comprehensive income and amortized into earnings based on the settlement period being hedged. Over the next twelve months, we expect to reclassify $1.4 million of losses to earnings as an increase in interest expense.

Cash Flow Hedges – Treasury Locks. We occasionally use treasury lock financial instruments to hedge the underlying U.S. treasury rates related to our anticipated issuances of debt. Cash gains or losses on the termination, or monetization, of such instruments are amortized to earnings using the effective interest method over the estimated term of the underlying fixed-rate debt. Each of our treasury lock transactions were designated as a cash flow hedge. The following table summarizes changes in our treasury lock portfolio since December 31, 2007 (dollars in millions).

	Notional Value	Cash Losses (1)
Treasury lock portfolio, December 31, 2007	$ 600.0	$ --
First quarter of 2008 terminations	(350.0)	27.7
Second quarter of 2008 terminations	(250.0)	12.7
Treasury lock portfolio, September 30, 2008	$ --	$ 40.4

(1) Cash losses are included in net interest rate financial instrument losses in the Unaudited Condensed Statements of Consolidated Comprehensive Income.

We expect to reclassify $1.8 million of cumulative net gains from the monetization of treasury lock financial instruments to earnings (as a decrease in interest expense) over the next twelve months. This includes financial instruments that were settled in years prior to 2008.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and certain petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risks associated with such products, we may enter into commodity financial instruments.

The primary purpose of our commodity risk management activities is to reduce our exposure to price risks associated with (i) natural gas purchases, (ii) the value of NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas, NGLs or certain petrochemical products. From time to time, we inject natural gas into storage and may utilize hedging instruments to lock in the value of our inventory positions. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

We have segregated our commodity financial instruments portfolio between those financial instruments utilized in connection with our natural gas marketing activities and those used in connection with our NGL and petrochemical operations.

Natural gas marketing activities. At September 30, 2008 and December 31, 2007, the aggregate fair values of those financial instruments utilized in connection with our natural gas marketing activities was an asset of $0.8 million and a liability of $0.3 million, respectively. Our natural gas marketing business and its related use of financial instruments has increased since December 31, 2007. For additional information regarding our natural gas marketing activities, see Note 12. We currently utilize mark-to-market accounting for substantially all of the financial instruments utilized in connection with our natural gas marketing activities. The following table presents gains and losses recognized in earnings from this portion of the commodity financial instruments portfolio for the periods indicated (dollars in millions):

Three months ended September 30, 2008	Gains	$ 13.2
Three months ended September 30, 2007	Losses	$ (0.6)

Nine months ended September 30, 2008	Gains	$	7.8
Nine months ended September 30, 2007	Losses	$	(0.1)

NGL and petrochemical operations. At September 30, 2008 and December 31, 2007, the aggregate fair values of financial instruments utilized in connection with our NGL and petrochemical operations were liabilities of $116.6 million and $19.0 million, respectively. The change in fair value between December 31, 2007 and September 30, 2008 is primarily due to a decrease in the price of natural gas and an increase in volumes hedged. Almost all of the financial instruments within this portion of the commodity financial instruments portfolio are accounted for as cash flow hedges, with a small number accounted for using mark-to-market accounting.

EPO has employed a program to economically hedge a portion of earnings from its natural gas processing business (a component of its NGL Pipelines & Services business segment). This program consists of (i) the forward sale of a portion of EPO's expected equity NGL production volumes at fixed prices through 2009 and (ii) the purchase (using commodity financial instruments) of the amount of natural gas expected to be consumed as plant thermal reduction ("PTR") in the production of such equity NGL volumes. The objective of this strategy is to hedge a level of gross margins (i.e., NGL sales revenues less actual costs for PTR and the gain or loss on the PTR hedge) associated with the forward sales contracts by fixing the cost of natural gas used for PTR, through the use of commodity financial instruments. At September 30, 2008, this hedging program had hedged future gross margins before plant operating expenses of $588.8 million for 28.8 million barrels of forecasted NGL forward sales transactions extending through 2009.

NGL forward sales contracts are not accounted for as financial instruments under SFAS 133; therefore, changes in the aggregate economic value of these sales contracts are not reflected in earnings and comprehensive income until the volumes are delivered to customers. On the other hand, the commodity financial instruments used to purchase the related quantities of PTR (i.e., "PTR hedges") are accounted for as cash flow hedges; therefore, changes in the aggregate fair value of the PTR hedges are presented in other comprehensive income.

Prior to actual settlement, if the market price of natural gas is less than the price stipulated in a PTR hedge, we recognize an unrealized loss in other comprehensive income for the excess of the natural gas price stated in the PTR hedge over the market price. To the extent that we realize such financial losses upon settlement of the instrument, the losses are added to the actual cost we have to pay for PTR (which would then be based on the lower market price). The end result of this relationship – financial gain/loss on the PTR hedges plus the market price of actual natural gas purchases at the time of consumption – is that our total cost of natural gas used for PTR approximates the amount we originally hedged under this program The converse is true if the price of natural gas decreases. During the third quarter of 2008, the price of natural gas decreased approximately 45% from June 30, 2008. As a result, we recognized unrealized losses in other comprehensive income with respect to the PTR hedges of $258.4 million during the third quarter of 2008. For the nine months ended September 30, 2008, we recognized unrealized losses in other comprehensive income of $126.0 million with respect to the PTR hedging program. Once the forecasted NGL forward sales transactions occur, any realized gains and losses on the cash flow hedges would be reclassified into earnings at that time.

The following table presents gains and losses recognized in earnings from this portion of the commodity financial instruments portfolio for the periods indicated (dollars in millions):

Three months ended September 30, 2008 (1)	Losses	$	(7.2)
Three months ended September 30, 2007	Losses	$	(10.1)
Nine months ended September 30, 2008 (2)	Gains	$	1.7
Nine months ended September 30, 2007	Losses	$	(11.9)

(1) Includes ineffectiveness of $5.6 million (an expense).

(2) Includes ineffectiveness of $2.8 million (an expense).

A significant number of the financial instruments in this portfolio hedge the purchase of physical natural gas. If natural gas prices fall below the price stipulated in such financial instruments, we recognize a liability for the difference; however, if prices partially or fully recover, this liability would be reduced or eliminated, as appropriate. Our restricted cash balance at September 30, 2008 was $183.2 million in order to meet commodity exchange deposit requirements and the negative change in the fair value of our commodity positions.

Foreign Currency Hedging Program

We are exposed to foreign currency exchange rate risk primarily through our Canadian NGL marketing subsidiary. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Canadian dollar. We attempt to hedge this risk using foreign exchange purchase contracts to fix the exchange rate. Mark-to-market accounting is utilized for these contracts, which typically have a duration of one month. For the nine months ended September 30, 2008, we recorded minimal gains from these financial instruments. No such amounts were recorded in the third quarter of 2008.

Adoption of SFAS 157 - Fair Value Measurements

On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. We will adopt the provisions of SFAS 157 that apply to nonfinancial assets and liabilities on January 1, 2009. SFAS 157 defines fair value 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. These assumptions include 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.

SFAS 157 established a three-tier hierarchy 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 characteristics of fair value amounts classified within each level of the SFAS 157 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 in sufficient frequency so as to provide pricing information on an ongoing basis (e.g., the NYSE or NYMEX). Level 1 primarily consists of financial assets and liabilities such as exchange-traded financial instruments, publicly-traded equity securities and U.S. government treasury securities.

§ 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, time value of money, volatility factors for stocks and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are (i) 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). Level 2 includes non-exchange-traded instruments such as over-the-counter forward contracts, options and repurchase agreements.

§

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 the reporting entity's own 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 in the circumstances, which might include the reporting entity's internally-developed data. The reporting entity must not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Level 3 inputs are typically used in connection with internally developed valuation methodologies where management makes its best estimate of an instrument's fair value. Level 3 generally includes specialized or unique financial instruments that are tailored to meet a customer's specific needs.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities measured on a recurring basis at September 30, 2008. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels. At September 30, 2008 there were no Level 1 financial assets or liabilities.

	Level 2	Level 3	Total
Financial assets:			
Commodity financial instruments	$ 15,320	$ 18,445	$ 33,765
Interest rate financial instruments	13,151	--	13,151
Total	$ 28,471	$ 18,445	$ 46,916
Financial liabilities:			
Commodity financial instruments	$ 149,577	$ --	$ 149,577
Interest rate financial instruments	4,301	--	4,301
Total	$ 153,878	$ --	$ 153,878

Fair values associated with our interest rate, commodity and foreign currency financial instrument portfolios were developed using available market information and appropriate valuation techniques in accordance with SFAS 157.

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

Balance, January 1, 2008	$ (4,660)
Total gains (losses) included in:	
Net income (1)	(2,254)
Other comprehensive income	2,419
Purchases, issuances, settlements	1,861
Balance, March 31, 2008	(2,634)
Total gains (losses) included in:	
Net income (1)	322
Other comprehensive income	(2,428)
Purchases, issuances, settlements	71
Balance, June 30, 2008	(4,669)
Total gains (losses) included in:	
Net income (1)	(2,190)
Other comprehensive loss	23,114
Purchases, issuances, settlements	2,190
Balance, September 30, 2008	$ 18,445

(1) Net income includes commodity financial instrument losses of $2.2 million and $4.1 million, respectively, recorded in revenue for the three and nine months ended September 30, 2008. There were no unrealized gains included in these amounts.

Note 5. Inventories

Our inventory amounts were as follows at the dates indicated:

	September 30, 2008	December 31, 2007
Working inventory (1)	$ 602,909	$ 342,589
Forward-sales inventory (2)	50,874	11,693
Total inventory	$ 653,783	$ 354,282

(1) Working inventory is comprised of inventories of natural gas, NGLs and certain petrochemical products that are either available-for-sale or used in the provision for services.
(2) Forward sales inventory consists of segregated NGL and natural gas volumes dedicated to the fulfillment of forward-sales contracts.

Our inventory values reflect payments for product purchases, freight charges associated with such purchase volumes, terminal and storage fees, vessel inspection costs, demurrage charges and other related costs. We value our inventories at the lower of average cost or market.

Operating costs and expenses, as presented on our Unaudited Condensed Statements of Consolidated Operations, include cost of sales amounts related to the sale of inventories. Our cost of sales amounts were $5.47 billion and $–––3.53 billion for the three months ended September 30, 2008 and 2007, respectively. For the nine months ended September 30, 2008 and 2007, our cost of sales were $15.88 billion and $9.89 billion, respectively.

Due to fluctuating commodity prices in the NGL, natural gas and petrochemical industry, we recognize lower of cost or market ("LCM") adjustments when the carrying value of our inventories exceed their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized. For the three months ended September 30, 2008 and 2007, we recognized LCM adjustments of approximately $36.4 million and $0.2 million, respectively. We recognized LCM adjustments of $41.3 million and $13.3 million for the nine months ended September 30, 2008 and 2007, respectively.

Note 6. Property, Plant and Equipment

Our property, plant and equipment values and related accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	September 30, 2008	December 31, 2007
Plants and pipelines (1)	3-35(5)	$ 12,019,063	$ 10,884,819
Underground and other storage facilities (2)	5-35(6)	784,808	720,795
Platforms and facilities (3)	20-31	634,809	637,812
Transportation equipment (4)	3-10	35,865	32,627
Land		50,560	48,172
Construction in progress		1,417,947	1,173,988
Total		14,943,052	13,498,213
Less accumulated depreciation		2,249,433	1,910,949
Property, plant and equipment, net		$ 12,693,619	$ 11,587,264

(1) Plants and pipelines include processing plants; NGL, petrochemical, oil and natural gas 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; storage tanks; water wells; and related assets.
(3) Platforms and facilities include offshore platforms and related facilities and other associated assets.
(4) Transportation equipment includes vehicles and similar assets used in our operations.
(5) In general, the estimated useful lives of major components of this category are as follows: processing plants, 20-35 years; pipelines, 18-35 years (with some equipment at 5 years); terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings, 20-35 years; and laboratory and shop equipment, 5-35 years.
(6) In general, the estimated useful lives of major components of this category are as follows: underground storage facilities, 20-35 years (with some components at 5 years); storage tanks, 10-35 years; and water wells, 25-35 years (with some components at 5 years).

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

	For the Three Months Ended September 30, 2008	For the Three Months Ended September 30, 2007	For the Nine Months Ended September 30, 2008	For the Nine Months Ended September 30, 2007
Depreciation expense (1)	$ 115,517	$ 108,692	$ 339,332	$ 302,758
Capitalized interest (2)	$ 17,284	$ 18,656	$ 53,019	$ 59,795

(1) Depreciation expense is a component of costs and expenses as presented in 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.

We reviewed assumptions underlying the estimated remaining useful lives of certain of our assets during the first quarter of 2008. As a result of our review, effective January 1, 2008, we revised the remaining useful lives of these assets, most notably the assets that constitute our Texas Intrastate System. This revision increased the remaining useful life of such assets to incorporate recent data showing that proved natural gas reserves supporting throughput and processing volumes for these assets have changed since our original determination made in September 2004. These revisions will prospectively reduce our depreciation expense on assets having carrying values totaling $2.72 billion as of January 1, 2008. On average, we extended the life of these assets by 3.1 years. As a result of this change in estimate, depreciation expense included in operating income and net income for the three and nine months ended September 30, 2008 decreased by approximately $5.0 million and $15.0 million, respectively, which increased our earnings per unit by $0.01 and $0.03, respectively, from what it would have been absent the change.

Asset retirement obligations

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of a tangible long-lived asset that results from its acquisition, construction, development or normal operation or a combination of these factors. The following table summarizes amounts recognized in connection with AROs since December 31, 2007:

ARO liability balance, December 31, 2007	$ 40,614
Liabilities incurred	810
Liabilities settled	(7,154)
Revisions in estimated cash flows	2,411
Accretion expense	1,660
ARO liability balance, September 30, 2008	$ 38,341

Property, plant and equipment at September 30, 2008 and December 31, 2007 includes $8.8 million and $10.6 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

Note 7. Investments in and Advances to Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for using the equity method of accounting. Our investments in and advances to unconsolidated affiliates are grouped according to the business segment to which they relate. See Note 12 for a general discussion of our business segments. The following table presents our investments in and advances to unconsolidated affiliates at the dates indicated.

	Ownership Percentage at September 30, 2008	September 30, 2008	December 31, 2007
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C. ("VESCO")	13.1%	$ 38,542	$ 40,129
K/D/S Promix, L.L.C. ("Promix")	50.0%	47,291	51,537
Baton Rouge Fractionators LLC ("BRF")	32.2%	25,410	25,423
Onshore Natural Gas Pipelines & Services:			
Jonah Gas Gathering Company ("Jonah")	19.4%	278,736	235,837
Evangeline (2)	49.5%	4,494	3,490
White River Hub, LLC ("White River Hub") (1)	50.0%	19,654	--
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36.0%	59,364	58,423
Cameron Highway Oil Pipeline Company ("Cameron Highway")	50.0%	260,713	256,588
Deepwater Gateway, L.L.C. ("Deepwater Gateway")	50.0%	109,263	111,221
Neptune Pipeline Company, L.L.C. ("Neptune")	25.7%	52,278	55,468

Nemo Gathering Company, LLC ("Nemo")	33.9%	784	2,888
Texas Offshore Port System ("TOPS")	33.3%	2,355	--
Petrochemical Services:			
Baton Rouge Propylene Concentrator LLC ("BRPC")	30.0%	14,255	13,282
La Porte (3)	50.0%	4,054	4,053
Total		$ 917,193	$ 858,339

(1) In February 2008, we acquired a 50.0% ownership interest in White River Hub.
(2) Refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.
(3) Refers to our ownership interests in La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively.

On occasion, the price we pay to acquire a non-controlling ownership interest in a company exceeds the underlying book value of the net assets we acquire. Such excess cost amounts are included within the carrying values of our investments in and advances to unconsolidated affiliates. At September 30, 2008 and December 31, 2007, our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway and Jonah included excess cost amounts totaling $44.1 million and $43.8 million, respectively.

These amounts are attributable to the excess of the fair value of each entity's tangible assets over their respective book carrying values at the time we acquired an interest in each entity. Amortization of such excess cost amounts was $0.5 million during each of the three months ended September 30, 2008 and 2007. For each of the nine months ended September 30, 2008 and 2007, amortization of such amounts was $1.5 million.

The following table presents our equity in earnings of unconsolidated affiliates by business segment for the periods indicated:

	For the Three Months Ended September 30, 2008	For the Three Months Ended September 30, 2007	For the Nine Months Ended September 30, 2008	For the Nine Months Ended September 30, 2007
NGL Pipelines & Services	$ 3,009	$ 2,684	$ 2,288	$ 4,364
Onshore Natural Gas Pipelines & Services	5,598	2,351	16,883	4,592
Offshore Pipelines & Services	5,987	8,557	27,914	3,786
Petrochemical Services	282	368	952	1,186
Total	$ 14,876	$ 13,960	$ 48,037	$ 13,928

On a quarterly basis, we monitor the underlying business fundamentals of our investments in unconsolidated affiliates and test such investments for impairment when impairment indicators are present. As a result of our reviews for the third quarter of 2008, no impairment charges were required. We have the intent and ability to hold these investments, which are integral to our operations.

Summarized Financial Information of Unconsolidated Affiliates

The following tables present unaudited income statement data for our current unconsolidated affiliates, aggregated by business segment, for the periods indicated (on a 100% basis).

	Summarized Income Statement Information for the Three Months Ended					
	September 30, 2008			September 30, 2007		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
NGL Pipelines & Services	$ 75,108	$ 9,742	$ 6,788	$ 49,579	$ 15,435	$ 16,118
Onshore Natural Gas Pipelines & Services	188,887	28,953	27,911	126,042	24,659	23,447
Offshore Pipelines & Services	31,926	12,812	11,976	39,331	21,363	19,974
Petrochemical Services	5,596	1,105	1,111	4,894	1,480	1,492

	Summarized Income Statement Information for the Nine Months Ended					
	September 30, 2008			September 30, 2007		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
NGL Pipelines & Services	$ 217,822	$ 17,749	$ 15,049	$ 150,367	$ 17,916	$ 19,873
Onshore Natural Gas Pipelines & Services	492,455	88,677	85,295	360,072	71,472	67,862
Offshore Pipelines & Services	115,018	62,363	57,202	116,957	65,227	34,204
Petrochemical Services	16,592	3,891	3,907	15,416	4,770	4,832

White River Hub Joint Venture

In February 2008, we formed a joint venture, White River Hub, with a wholly-owned subsidiary of Questar Corporation to design, construct, own and operate a natural gas hub located in the vicinity of Meeker, Colorado. White River Hub will construct a FERC-regulated interstate natural gas transmission system for the purpose of providing natural gas transportation and hub services to its customers. The newly constructed natural gas hub will connect six interstate natural gas pipelines in northwest Colorado and have a capacity in excess of 2.0 billion cubic feet per day ("Bcf/d"). This project is expected to be completed during the fourth quarter of 2008 and our share of the estimated construction costs is $22.1 million.

Texas Offshore Port System Joint Venture

In August 2008, we, together with TEPPCO and Oiltanking Holding Americas, Inc. (“Oiltanking”), announced the formation of a joint venture to design, construct, operate and own a Texas offshore crude oil port and related pipeline and storage infrastructure that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. Demand for such projects is being driven by planned and expected refinery expansions along the Gulf Coast, expected increases in shipping traffic and operating limitations of regional ship channels.

The joint venture’s primary project, referred to as “TOPS,” includes (i) an offshore port (which will be located approximately 36 miles from Freeport, Texas), (ii) an onshore storage facility with approximately 3.9 million barrels of crude oil storage capacity, and (iii) an 85-mile crude oil pipeline system having a transportation capacity of up to 1.8 million barrels per day, that will extend from the offshore port to a Texas City, Texas storage facility. TOPS is expected to begin service as early as the fourth quarter of 2010. The joint venture’s second and complementary project, referred to as the Port Arthur Crude Oil Express (or “PACE”) will transport crude oil from Texas City, including crude oil from TOPS, and will consist of a 75-mile pipeline and 1.2 million barrels of crude oil storage capacity in the Port Arthur, Texas area. PACE is expected to begin service as early as the third quarter of 2010. Development of the TOPS and PACE projects is supported by long-term contracts with affiliates of Motiva Enterprises LLC and Exxon Mobil Corporation, which have committed a combined 725,000 barrels per day of crude oil to the projects.

We, TEPPCO and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such capital expenditures occurring in 2009 and 2010. We and TEPPCO have each guaranteed up to approximately $700.0 million of the capital contribution obligations of our respective subsidiary partners in the joint venture. As of September 30, 2008, our investment in TOPS was $2.4 million.

Note 8. Business Combinations

Acquisition of Remaining Interest in Dixie

In August 2008, we acquired the remaining 25.8% ownership interest in Dixie for $57.1 million. As a result of this transaction, we own 100% of Dixie, which owns a 1,300-mile pipeline system that delivers NGLs (primarily propane and other chemical feedstocks) to customers along the U.S. Gulf Coast and southeastern United States.

Purchase Price Allocations

We accounted for business combinations completed during the nine months ended September 30, 2008 using the purchase method of accounting and, accordingly, such costs have been allocated to assets acquired and liabilities assumed based on estimated preliminary fair values. Such preliminary values have been developed using recognized business valuation techniques and are subject to change pending a final valuation analysis. We expect to finalize the purchase price allocations for these transactions during 2008.

	Dixie	South Monco (1)	Total
Assets acquired in business combination:			
Current assets	$ --	$ 35	$ 35
Property, plant and equipment, net	24,114	(12,781)	11,333
Intangible assets	--	12,747	12,747
Total assets acquired	24,114	1	24,115
Liabilities assumed in business combination:			
Minority interest	7,631	--	7,631
Total liabilities assumed	7,631	--	7,631
Total assets acquired plus liabilities assumed	31,745	1	31,746
Total cash used for business combinations	57,089	1	57,090
Goodwill	$ 25,344	$ --	$ 25,344

(1) Represents non-cash reclassification adjustments to December 2007 preliminary fair value estimates for assets acquired in the South Monco natural gas pipeline acquisition.

Note 9. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	September 30, 2008			December 31, 2007		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services	$ 523,401	$ (174,863)	$ 348,538	$ 520,025	$ (146,954)	$ 373,071
Onshore Natural Gas Pipelines & Services	476,298	(133,962)	342,336	463,551	(109,399)	354,152
Offshore Pipelines & Services	207,012	(86,797)	120,215	207,012	(73,954)	133,058
Petrochemical Services	67,906	(12,682)	55,224	67,906	(11,187)	56,719
Total	$ 1,274,617	$ (408,304)	$ 866,313	$ 1,258,494	$ (341,494)	$ 917,000

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
NGL Pipelines & Services	$ 9,203	$ 8,869	$ 27,908	$ 26,912
Onshore Natural Gas Pipelines & Services	8,014	7,946	24,564	24,154

Offshore Pipelines & Services	4,135	4,745	12,843	14,733
Petrochemical Services	499	499	1,495	1,495
Total	$ 21,851	$ 22,059	$ 66,810	$ 67,294

For the remainder of 2008, amortization expense associated with our intangible assets is currently estimated at $21.5 million.

Goodwill

The following table summarizes our goodwill amounts by segment at the dates indicated:

	September 30, 2008	December 31, 2007
NGL Pipelines & Services (1)	$ 179,050	$ 153,706
Onshore Natural Gas Pipelines & Services	282,121	282,121
Offshore Pipelines & Services	82,135	82,135
Petrochemical Services	73,690	73,690
Total	$ 616,996	$ 591,652

(1) See Note 8 for information regarding our recent acquisition of the remaining ownership interests in Dixie, which resulted in additional goodwill of $25.3 million.

Note 10. Debt Obligations

Our consolidated debt obligations consisted of the following at the dates indicated:

	September 30, 2008	December 31, 2007
EPO senior debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due November 2012	$ 1,150,701	$ 725,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed-rate, due February 2013	350,000	350,000
Senior Notes D, 6.875% fixed-rate, due March 2033	500,000	500,000
Senior Notes F, 4.625% fixed-rate, due October 2009	500,000	500,000
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000	650,000
Senior Notes H, 6.65% fixed-rate, due October 2034	350,000	350,000
Senior Notes I, 5.00% fixed-rate, due March 2015	250,000	250,000
Senior Notes J, 5.75% fixed-rate, due March 2035	250,000	250,000
Senior Notes K, 4.950% fixed-rate, due June 2010	500,000	500,000
Senior Notes L, 6.30% fixed-rate, due September 2017	800,000	800,000
Senior Notes M, 5.65% fixed-rate, due April 2013	400,000	--
Senior Notes N, 6.50% fixed-rate, due January 2019	700,000	--
Petal GO Zone Bonds, variable rate, due August 2037	57,500	57,500
Duncan Energy Partners' debt obligation:		
$300 Million Revolving Credit Facility, variable rate, due February 2011	212,000	200,000
Dixie Revolving Credit Facility, variable rate, due June 2010	10,000	10,000
Total principal amount of senior debt obligations	7,184,201	5,646,500
EPO Junior Subordinated Notes A, fixed/variable rates, due August 2066	550,000	550,000
EPO Junior Subordinated Notes B, fixed/variable rates, due January 2068	700,000	700,000
Total principal amount of senior and junior debt obligations	8,434,201	6,896,500
Other, non-principal amounts:		
Change in fair value of debt-related financial instruments (see Note 4)	20,096	14,839

Unamortized discounts, net of premiums	(7,405)	(5,194)
Unamortized deferred net gains related to terminated interest rate swaps (see Note 4)	11,303	--
Total other, non-principal amounts	23,994	9,645
Long-term debt	$ 8,458,195	$ 6,906,145
Standby letters of credit outstanding	$ 61,100	$ 1,100

Enterprise Products Partners L.P. acts as guarantor of the consolidated debt obligations of EPO with the exception of Dixie's revolving credit facility and Duncan Energy Partners' revolving credit facility. 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.

We consolidate the debt of Dixie and Duncan Energy Partners; however, neither Enterprise Products Partners L.P. nor EPO has the obligation to make interest or debt payments with respect to such obligations.

With respect to debt agreements existing at September 30, 2008, there have been no significant changes in the terms of our consolidated debt obligations since December 31, 2007.

Letters of credit. During the third quarter of 2008, a $60.0 million letter of credit was issued under EPO's Multi-Year Revolving Credit Facility to support our NYMEX margin requirements for natural gas financial instruments that are part of an economic hedge related to our natural gas processing business. In October 2008, EPO entered into a $100.0 million letter of credit facility. EPO issued a $70.0 million letter of credit under this new facility that replaced the letter of credit issued under its Multi-Year Revolving Credit Facility which was outstanding at September 30, 2008.

Senior Notes M and N. In April 2008, EPO sold $400.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes M") and $700.0 million in principal amount of 10-year senior unsecured notes ("Senior Notes N") under its universal registration statement. Senior Notes M were issued at 99.906% of their principal amount, have a fixed interest rate of 5.65% and mature in April 2013. Senior Notes N were issued at 99.866% of their principal amount, have a fixed interest rate of 6.50% and mature in January 2019.

Senior Notes M pay interest semi-annually in arrears on April 1 and October 1 of each year. Senior Notes N pay interest semi-annually in arrears on January 31 and July 31 of each year. Net proceeds from the issuance of Senior Notes M and N were used to temporarily reduce indebtedness outstanding under the EPO Multi-Year Revolving Credit Facility.

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

Covenants

We are in compliance with the covenants of our consolidated debt agreements at September 30, 2008 and December 31, 2007.

Information regarding variable interest rates paid

The following table presents the weighted-average interest rate paid on our consolidated variable-rate debt obligations during the nine months ended September 30, 2008.

	Weighted-average interest rate paid
EPO's Multi-Year Revolving Credit Facility	3.62%
Duncan Energy Partners' Revolving Credit Facility	4.15%
Dixie Revolving Credit Facility	3.25%
Petal GO Zone Bonds	2.27%

Consolidated debt maturity table

The following table presents the scheduled maturities of principal amounts of our consolidated debt obligations for the next five years and in total thereafter.

2008	$ --
2009	500,000
2010	564,000
2011	662,000
2012	1,150,701
Thereafter	5,557,500
Total scheduled principal payments	$ 8,434,201

Debt Obligations of Unconsolidated Affiliates

We have two unconsolidated affiliates with long-term debt obligations. The following table shows (i) our ownership interest in each entity at September 30, 2008, (ii) total debt of each unconsolidated affiliate at September 30, 2008 (on a 100% basis to the affiliate) and (iii) the corresponding scheduled maturities of such debt.

	Our Ownership Interest	Total	Scheduled Maturities of Debt 2008	2009	2010	2011	2012	After 2012
Poseidon	36.0%	$ 109,000	$ --	$ --	$ --	$ 109,000	$ --	$ --
Evangeline	49.5%	20,650	5,000	5,000	3,150	7,500	--	--
Total		$ 129,650	$ 5,000	$ 5,000	$ 3,150	$ 116,500	$ --	$ --

The credit agreements of our unconsolidated affiliates contain various affirmative and negative covenants, including financial covenants. These businesses were in compliance with such covenants at September 30, 2008. The credit agreements of our unconsolidated affiliates restrict their ability to pay cash dividends if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend is scheduled to be paid.

There have been no significant changes in the terms of the debt obligations of our unconsolidated affiliates since those reported in our Annual Report on Form 10-K for the year ended December 31, 2007.

Note 11. Partners' Equity and Distributions

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Fifth Amended and Restated Agreement of Limited Partnership (together with all amendments thereto, the "Partnership Agreement"). We are managed by our general partner, EPGP.

In accordance with the Partnership Agreement, capital accounts are maintained for our general partner and limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the equity accounts reflected under GAAP in our condensed consolidated financial statements.

Our Partnership Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that our limited partners and general partner will receive. The Partnership Agreement also contains provisions for the allocation of net earnings and losses to our limited partners and general partner. For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interests. Normal income and loss allocations according to percentage interests are done only after giving effect to priority earnings allocations in an amount equal to incentive cash distributions allocated to our general partner.

Equity Offerings and Registration Statements

In general, the Partnership Agreement authorizes us to issue an unlimited number of additional limited partner interests and other equity securities for such consideration and on such terms and conditions as may be established by EPGP in its sole discretion (subject, under certain circumstances, to the approval of our unitholders).

We have a universal shelf registration statement on file with the SEC registering the issuance of an unlimited amount of equity and debt securities. In April 2008, EPO sold $1.10 billion in principal amount of senior notes under our universal shelf registration statement. For additional information regarding this debt offering, see Note 10.

We also have on file with the SEC a registration statement authorizing the issuance of up to 25,000,000 common units in connection with our distribution reinvestment plan ("DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units of our partnership. An aggregate of 1,895,776 of our common units were issued in connection with the DRIP and the employee unit purchase plan ("EUPP") during the nine months ended September 30, 2008. The issuance of these units generated $56.5 million in net proceeds that we used for general partnership purposes. In November 2008, affiliates of EPCO, including Enterprise GP Holdings, expect to reinvest $67.0 million of their distributions through the DRIP.

The following table reflects the number of common units issued and the net proceeds received from other common unit offerings completed during the nine months ended September 30, 2008:

		Net Proceeds from Sale of Common Units		
	Number of Common Units Issued	Contributed by Limited Partners	Contributed by General Partner	Total Net Proceeds
February DRIP and EUPP	587,610	$ 17,651	$ 360	$ 18,011
May DRIP and EUPP	631,950	19,025	389	19,414
August DRIP and EUPP	676,216	18,687	381	19,068
Total 2008	1,895,776	$ 55,363	$ 1,130	$ 56,493

Summary of Changes in Outstanding Units

The following table summarizes changes in our outstanding units since December 31, 2007:

	Common Units	Restricted Common Units	Treasury Units
Balance, December 31, 2007	433,608,763	1,688,540	--
Common units issued in connection with DRIP and EUPP	1,895,776	--	--
Common units issued in connection with unit-based awards	21,905	--	--
Restricted units issued	--	750,900	--
Conversion of restricted units to common units	115,150	(115,150)	--
Acquisition of treasury units	(30,918)	--	30,918
Cancellation of treasury units	--	--	(30,918)
Forfeiture of restricted units	--	(84,677)	--
Balance, September 30, 2008	435,610,676	2,239,613	--

During the nine months ended September 30, 2008, 115,150 restricted unit awards vested and were converted to common units. Of this amount, 30,918 were sold back to us by employees to cover related withholding tax requirements. The total cost of these treasury units was approximately $795 thousand, of which $779 thousand was allocated to limited partners and the remainder to our general partner. Immediately upon acquisition, we cancelled such treasury units.

Summary of Changes in Limited Partners' Equity

The following table details the changes in limited partners' equity since December 31, 2007:

	Common Units	Restricted Common Units	Total
Balance, December 31, 2007	$ 5,976,947	$ 15,948	$ 5,992,895
Net income	617,761	2,733	620,494
Operating leases paid by EPCO	1,541	7	1,548
Cash distributions to partners	(661,137)	(2,809)	(663,946)
Unit option reimbursements to EPCO	(550)	--	(550)
Non-cash distributions	(5,006)	--	(5,006)
Acquisition of treasury units, limited partner share	--	(779)	(779)
Net proceeds from issuance of common units	55,363	--	55,363
Proceeds from exercise of unit options	680	--	680
Amortization of unit-based awards	4,862	8,769	13,631
Balance, September 30, 2008	$ 5,990,461	$ 23,869	$ 6,014,330

Distributions to Partners

The percentage interest of EPGP in our quarterly cash distributions is increased after certain specified target levels of quarterly distribution rates are met. At current distribution rates, we are in the highest tier of such incentive targets. EPGP's quarterly incentive distribution thresholds are as follows:

- 2% of quarterly cash distributions up to $0.253 per unit;
- 15% of quarterly cash distributions from $0.253 per unit up to $0.3085 per unit; and
- 25% of quarterly cash distributions that exceed $0.3085 per unit.

We paid incentive distributions of $32.0 million and $27.4 million to EPGP during the three months ended September 30, 2008 and 2007, respectively. During the nine months ended September 30, 2008 and 2007, we paid incentive distributions of $92.8 million and $79.0 million, respectively, to EPGP.

We paid aggregate distributions to our unitholders and general partner of $770.3 million during the nine months ended September 30, 2008. These distributions pertained to the nine month period ended June 30, 2008 (i.e., the fourth quarter of 2007, and first and second quarters of 2008). On November 12, 2008, we will pay a quarterly cash distribution of $0.5225 per unit with respect to the third quarter of 2008, to unitholders of record at the close of business on October 31, 2008.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) primarily includes the effective portion of the gain or loss on financial instruments designated and qualified as a cash flow hedge, foreign currency adjustments and Dixie's minimum pension liability adjustments. Amounts accumulated in other comprehensive income (loss) from cash flow hedges are reclassified into earnings in the same period(s) in which the hedged forecasted transactions (such as a forecasted forward sale of NGLs) affect earnings. If it becomes probable that the forecasted transaction will not occur, the net gain or loss in accumulated other comprehensive income (loss) must be immediately reclassified.

The following table presents the components of accumulated other comprehensive income (loss) at the dates indicated:

	September 30, 2008	December 31, 2007
Commodity financial instruments – cash flow hedges (1)	$ (129,913)	$ (21,619)
Interest rate financial instruments – cash flow hedges (1)	9,714	34,980
Foreign currency cash flow hedges (1)	--	1,308
Foreign currency translation adjustment (2)	1,652	1,200
Pension and postretirement benefit plans (3)	324	588
Total accumulated other comprehensive income (loss)	$ (118,223)	$ 16,457

(1) See Note 4 for additional information regarding financial instruments. The negative change in fair value of our commodity financial instruments between December 31, 2007 and September 30, 2008 is primarily due to a significant decrease in natural gas prices during the third quarter of 2008.
(2) Relates to transactions of our Canadian NGL marketing subsidiary.
(3) See Note 2 for additional information regarding Dixie's pension and postretirement benefit plans.

Note 12. Business Segments

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

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 senior 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 consolidated operating income before: (i) depreciation, amortization and accretion expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses from asset sales and related transactions; and (iv) general and administrative costs. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of changes in accounting principle. 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 intersegment and intrasegment transactions.

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of intercompany (both intersegment and intrasegment) transactions.

We include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers and/or suppliers. This method of operation enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our integrated midstream energy asset system (including the midstream energy assets of our equity method investees) provides services to producers and consumers of natural gas, NGLs, crude oil and certain petrochemicals. In general, hydrocarbons enter our asset system in a number of ways, such as an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an onshore natural gas gathering pipeline, an NGL fractionator, an NGL storage facility, or an NGL transportation or distribution pipeline.

Many of our equity investees are included within our integrated midstream asset system. For example, we have ownership interests in several offshore natural gas and crude oil pipelines. Other examples include our use of the Promix NGL fractionator to process mixed NGLs extracted by our gas plants. The fractionated NGLs we receive from Promix can then be sold in our NGL marketing activities. Given the integral nature of our equity method investees to our operations, we believe the presentation of earnings from such investees as a component of gross operating margin and operating income is meaningful and appropriate.

Historically, substantially all of our consolidated revenues were earned in the United States and derived from a wide customer base. The majority of our plant-based operations are located in Texas, Louisiana, Mississippi, New Mexico, Colorado and Wyoming. Our natural gas, NGL and crude oil pipelines are located in a number of regions of the United States including (i) the Gulf of Mexico offshore Texas and Louisiana; (ii) the south and southeastern United States (primarily in Texas, Louisiana, Mississippi and Alabama); and (iii) certain regions of the central and western United States, including the Rocky Mountains. Our marketing activities are headquartered in Houston, Texas and serve customers in a number of regions of the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are assigned to each segment on the basis of each asset's or investment's principal operations. The principal reconciling difference between consolidated property, plant and equipment and the total value of segment assets is construction-in-progress. Segment assets represent the net book carrying value of facilities and other assets that contribute to gross operating margin of that particular segment. Since assets under construction generally do not contribute to segment gross operating margin, such assets are excluded from segment asset totals until they are placed in service. Consolidated intangible assets and goodwill are assigned to each segment based on the classification of the assets to which they relate.

We consolidate the financial statements of Duncan Energy Partners with those of our own. As a result, our consolidated gross operating margin amounts include 100% of the gross operating margin amounts of Duncan Energy Partners.

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

		For the Three Months Ended September 30, 2008	2007	For the Nine Months Ended September 30, 2008	2007
Revenues (1)		$ 6,297,902	$ 4,111,996	$ 18,322,052	$ 11,647,656
Less:	Operating costs and expenses (1)	(5,971,942)	(3,896,411)	(17,243,070)	(10,981,562)
Add:	Equity in earnings of unconsolidated affiliates (1)	14,876	13,960	48,037	13,928
	Depreciation, amortization and accretion in operating costs and expenses (2)	138,417	133,869	408,601	374,522
		526	526	1,579	1,579

Operating lease expense paid by EPCO (2)				
Loss (gain) from asset sales and related transactions in operating costs and expenses (2)	(857)	(219)	(1,699)	5,445
Total segment gross operating margin	$ 478,922	$ 363,721	$ 1,535,500	$ 1,061,568

(1) These amounts are taken from our Unaudited Condensed Statements of Consolidated Operations.
(2) These non-cash expenses are taken from the operating activities section of our Unaudited Condensed Statements of Consolidated Cash Flows.

A reconciliation of our total segment gross operating margin to operating income and income before provision for income taxes and minority interest follows:

	For the Three Months Ended September 30, 2008	2007	For the Nine Months Ended September 30, 2008	2007
Total segment gross operating margin	$ 478,922	$ 363,721	$ 1,535,500	$ 1,061,568
Adjustments to reconcile total segment gross operating margin				
to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(138,417)	(133,869)	(408,601)	(374,522)
Operating lease expense paid by EPCO	(526)	(526)	(1,579)	(1,579)
Gain (loss) from asset sales and related transactions in operating				
costs and expenses	857	219	1,699	(5,445)
General and administrative costs	(21,720)	(18,715)	(66,901)	(66,706)
Operating income	319,116	210,830	1,060,118	613,316
Other expense, net	(101,479)	(83,369)	(287,672)	(213,327)
Income before provision for income taxes and minority interest	$ 217,637	$ 127,461	$ 772,446	$ 399,989

The following table summarizes the contribution to consolidated revenues from the sale of NGL, natural gas and petrochemical products for the periods indicated:

	For the Three Months Ended September 30, 2008	2007	For the Nine Months Ended September 30, 2008	2007
NGL Pipelines & Services:				
Sale of NGL products	$ 4,271,467	$ 2,837,465	$ 12,550,220	$ 7,952,147
Percent of consolidated revenues	68%	69%	68%	68%
Onshore Natural Gas Pipelines & Services:				
Sale of natural gas	851,748	406,482	2,407,930	1,190,235
Percent of consolidated revenues	14%	10%	13%	10%
Petrochemical Services:				
Sale of petrochemical products	708,745	444,670	1,928,840	1,268,731
Percent of consolidated revenues	11%	11%	11%	11%

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

	Reportable Segments					
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Offshore Pipelines & Services	Petrochemical Services	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:						
Three months ended September 30, 2008	$ 4,288,205	$ 823,245	$ 60,194	$ 826,099	$ --	$ 5,997,743
Three months ended September 30, 2007	2,873,937	428,807	54,444	575,969	--	3,933,157
Nine months ended September 30, 2008	12,544,242	2,456,275	197,326	2,300,602	--	17,498,445
Nine months ended September 30, 2007	8,261,659	1,304,239	142,557	1,559,887	--	11,268,342
Revenues (losses) from related parties:						
Three months ended September 30, 2008	140,839	154,566	4,754	--	--	300,159
Three months ended September 30, 2007	93,204	86,704	(1,069)	--	--	178,839
Nine months ended September 30, 2008	501,129	314,665	7,813	--	--	823,607
Nine months ended September 30, 2007	169,262	209,807	236	9	--	379,314
Intersegment and intrasegment revenues:						
Three months ended September 30, 2008	2,313,647	293,227	377	216,643	(2,823,894)	--
Three months ended September 30, 2007	1,265,697	57,635	484	132,844	(1,456,660)	--
Nine months ended September 30, 2008	6,431,479	635,992	1,109	529,821	(7,598,401)	--
Nine months ended September 30, 2007	3,540,347	119,121	1,531	360,885	(4,021,884)	--
Total revenues:						
Three months ended September 30, 2008	6,742,691	1,271,038	65,325	1,042,742	(2,823,894)	6,297,902
Three months ended September 30, 2007	4,232,838	573,146	53,859	708,813	(1,456,660)	4,111,996
Nine months ended September 30, 2008	19,476,850	3,406,932	206,248	2,830,423	(7,598,401)	18,322,052
Nine months ended September 30, 2007	11,971,268	1,633,167	144,324	1,920,781	(4,021,884)	11,647,656

Equity in earnings of unconsolidated affiliates:						
Three months ended September 30, 2008	3,009	5,598	5,987	282	--	14,876
Three months ended September 30, 2007	2,684	2,351	8,557	368	--	13,960
Nine months ended September 30, 2008	2,288	16,883	27,914	952	--	48,037
Nine months ended September 30, 2007	4,364	4,592	3,786	1,186	--	13,928
Gross operating margin by individual business segment and in total:						
Three months ended September 30, 2008	336,054	88,160	17,465	37,243	--	478,922
Three months ended September 30, 2007	190,209	75,424	46,676	51,412	--	363,721
Nine months ended September 30, 2008	943,445	321,237	134,353	136,465	--	1,535,500
Nine months ended September 30, 2007	589,708	235,102	97,429	139,329	--	1,061,568
Segment assets:						
At September 30, 2008	5,248,670	3,922,181	1,407,855	696,966	1,417,947	12,693,619
At December 31, 2007	4,570,555	3,702,297	1,452,568	687,856	1,173,988	11,587,264
Investments in and advances to unconsolidated affiliates (see Note 7):						
At September 30, 2008	111,243	302,884	484,757	18,309	--	917,193
At December 31, 2007	117,089	239,327	484,588	17,335	--	858,339
Intangible assets, net (see Note 9):						
At September 30, 2008	348,538	342,336	120,215	55,224	--	866,313
At December 31, 2007	373,071	354,152	133,058	56,719	--	917,000
Goodwill (see Note 9):						
At September 30, 2008	179,050	282,121	82,135	73,690	--	616,996
At December 31, 2007	153,706	282,121	82,135	73,690	--	591,652

Our natural gas marketing business, which is included in our Onshore Natural Gas Pipelines & Services segment, has increased significantly during 2008. These marketing activities have four primary objectives: (i) to mitigate risk; (ii) maximize the use of our natural gas assets; (iii) to provide real-time market intelligence; and (iv) to link our noncontiguous natural gas assets together to enhance the profitability of such operations. To achieve these objectives, our natural gas marketing activities transact with various parties to provide transportation, balancing, storage, supply and sales services. The majority of our natural gas marketing activities are focused on the Gulf Coast and Rocky Mountain regions.

Our natural gas marketing business acquires a significant portion of the natural gas it sells from our processing plants and attracts additional supplies from third parties at pipeline interconnects to facilitate incremental throughput on our natural gas transportation pipelines. This purchased gas is then sold to industrial consumers, utilities and power plants at prices that include a transportation fee. In addition, sales are made with third party marketing companies at industry hub locations in order to balance our supply/demand portfolio. Our purchase and sale transactions are typically based on published daily or monthly index prices. We utilize financial instruments to hedge various transactions within our natural gas marketing business (see Note 4).

We use third party transportation and storage capacity to link together our noncontiguous natural gas assets. Our natural gas marketing business contracts with third party transportation and storage providers to provide services on both a firm and interruptible basis. This strategy allows us to compliment and strengthen our portfolio of natural gas assets.

Note 13. Related Party Transactions

The following table summarizes our revenue and expense transactions with related parties for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Revenues from consolidated operations:				
EPCO and affiliates	$ 47,215	$ 12,673	$ 91,922	$ 42,778
Energy Transfer Equity and subsidiaries	99,583	78,957	412,975	121,521
Unconsolidated affiliates	153,361	87,209	318,710	215,015
Total	$ 300,159	$ 178,839	$ 823,607	$ 379,314
Operating costs and expenses:				
EPCO and affiliates	$ 87,991	$ 72,296	$ 274,406	$ 219,879
Energy Transfer Equity and subsidiaries	56,528	2,614	134,447	8,385
Unconsolidated affiliates	20,688	6,414	68,214	22,628
Total	$ 165,207	$ 81,324	$ 477,067	$ 250,892
General and administrative costs:				
EPCO and affiliates	$ 13,403	$ 11,504	$ 44,631	$ 45,292
Unconsolidated affiliates	(37)	--	(37)	--
Total	$ 13,366	$ 11,504	$ 44,594	$ 45,292
Other expense:				
EPCO and affiliates	$ --	$ --	$ (274)	$ 170

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 part of our consolidated group of companies:

§ EPCO and its private company subsidiaries;

§ EPGP, our sole general partner;

§ Enterprise GP Holdings, which owns and controls our general partner;

§ TEPPCO, which is owned and controlled by Enterprise GP Holdings; and

§ the Employee Partnerships (see Note 3).

We also have an ongoing relationship with Duncan Energy Partners, the financial statements of which are consolidated with those of our own. Our transactions with Duncan Energy Partners are eliminated in consolidation. A description of our relationship with Duncan Energy Partners is presented within this Note 13.

EPCO is a private company controlled by Dan L. Duncan, who is also a Director and Chairman of EPGP, our general partner. At September 30, 2008, EPCO and its affiliates beneficially owned 149,433,410 (or 34.1%) of our outstanding common units, which include 13,454,498 of our common units owned by Enterprise GP Holdings. In addition, at September 30, 2008, EPCO and its affiliates beneficially owned 77.8% of the limited partner interests of Enterprise GP Holdings and 100% of its general partner, EPE Holdings. Enterprise GP Holdings owns all of the membership interests of EPGP. The principal business activity of EPGP is to act as our managing partner. The executive officers and certain of the directors of EPGP and EPE Holdings are employees of EPCO.

As our general partner, EPGP received cash distributions of $106.4 million and $91.6 million from us during the nine months ended September 30, 2008 and 2007, respectively. These amounts include incentive distributions of $92.8 million and $79.0 million for the nine months ended September 30, 2008 and 2007, respectively.

We and EPGP are both separate legal entities apart from each other and apart from EPCO, Enterprise GP Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Enterprise GP Holdings and their respective other affiliates. EPCO and its private company subsidiaries depend on the cash distributions they receive from us, Enterprise GP Holdings and other investments to fund their other operations and to meet their debt obligations. EPCO and its private company affiliates received directly from us $300.2 million and $260.7 million in cash distributions during the nine months ended September 30, 2008 and 2007, respectively.

The ownership interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. In addition, substantially all of the ownership interests in us that are owned or controlled by EPCO and its affiliates, other than those interests owned by Enterprise GP Holdings, Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of a private company affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, TEPPCO and us.

We have entered into an agreement with an affiliate of EPCO to provide trucking services to us for the transportation of NGLs and other products. We also lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates.

EPCO Administrative Services Agreement

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. We, Duncan Energy Partners, Enterprise GP Holdings, TEPPCO and our respective general partners are parties to the ASA. The ACG Committees of each general partner have approved the ASA.

Under the ASA, we reimburse EPCO for all costs and expenses it incurs in providing management, administrative and operating services for us, including compensation of employees (i.e., salaries, medical benefits and retirement benefits). 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 stand-alone 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 stand-alone basis. The ASA also addresses potential conflicts in business opportunities that may arise among us, Enterprise GP Holdings, Duncan Energy Partners and other affiliates of EPCO.

Relationship with TEPPCO

TEPPCO became a related party to us in February 2005 when its general partner was acquired by private company affiliates of EPCO. Our relationship with TEPPCO was further reinforced by the acquisition of TEPPCO's general partner by Enterprise GP Holdings in May 2007. Enterprise GP Holdings also owns our general partner.

We received $47.2 million and $12.7 million from TEPPCO during the three months ended September 30, 2008 and 2007, respectively, from the sale of hydrocarbon products. We received $91.9 million and $42.8 million from TEPPCO during the nine months ended September 30, 2008 and 2007, respectively, from the sale of hydrocarbon products. We paid TEPPCO $5.9 million and $4.5 million for NGL pipeline transportation and storage services during the three months ended September 30, 2008 and 2007, respectively. We paid TEPPCO $21.9 million and $13.8 million for NGL pipeline transportation and storage services during the nine months ended September 30, 2008 and 2007, respectively.

In August 2006, we formed a joint venture with TEPPCO involving Jonah, which owns the Jonah Gas Gathering System located in the Greater Green River Basin of southwestern Wyoming. The Jonah Gas Gathering System gathers and transports natural gas produced from the Jonah and Pinedale fields to regional natural gas processing plants and major interstate pipelines that deliver natural gas to end-user markets. Currently, the gathering capacity of this system is 2.4 Bcf/d. We own an approximate 19.4% interest in Jonah and TEPPCO owns the remaining 80.6% interest. We account for our investment in the Jonah joint venture using the equity method of accounting.

During the first quarter of 2008, Jonah initiated a separate project to increase gathering capacity on that portion of its system that serves the Pinedale production field. This new project is expected to increase overall capacity of the Jonah Gas Gathering System by an additional 0.2 Bcf/d. The total anticipated cost of this new project is $125.0 million, of which we will be responsible for our share of the construction costs.

In August 2008, we, together with TEPPCO and Oiltanking, announced the formation of a joint venture to design, construct, operate and own a Texas offshore crude oil port and pipeline system to facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. See Note 7 for additional information regarding the Texas Offshore Port System joint venture.

Relationship with Duncan Energy Partners

On February 5, 2007, Duncan Energy Partners completed its initial public offering of 14,950,000 common units. At September 30, 2008, Enterprise Products Partners beneficially owned 5,351,571 of Duncan Energy Partners' common units. We also own the 2% general partner interest in Duncan Energy

Partners. EPO directs the business operations of Duncan Energy Partners through its ownership and control of the general partner of Duncan Energy Partners. For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own.

As a result of contributions EPO made at the time of Duncan Energy Partners' initial public offering in February 2007, Duncan Energy Partners owns 66% of the equity interests in the following entities and EPO owns the remaining 34% of the equity interests:

§ Mont Belvieu Caverns, LLC ("Mont Belvieu Caverns"),

§ Acadian Gas, LLC ("Acadian Gas"),

§ Sabine Propylene Pipeline L.P. ("Sabine Propylene"),

§ Enterprise Lou-Tex Propylene Pipeline L.P. ("Lou-Tex Propylene"), and

§ South Texas NGL Pipelines, LLC ("South Texas NGL").

We have significant involvement with all of the subsidiaries of Duncan Energy Partners, including the following types of transactions:

§ We utilize storage services provided by Mont Belvieu Caverns to support our Mont Belvieu fractionation and other businesses;

§ We buy natural gas from and sell natural gas to Acadian Gas in connection with its and our normal business activities; and

§ We are currently the sole shipper on the DEP South Texas NGL Pipeline System.

EPO may contribute or sell other equity interests in its subsidiaries, or other of its or its subsidiaries' assets, to Duncan Energy Partners. EPO has no obligation or commitment to make such contributions or sales to Duncan Energy Partners.

Effective February 1, 2007, EPO is allocated all operational measurement gains and losses relating to Mont Belvieu Caverns' underground storage activities. Operational measurement gains and losses are created when product is moved between storage wells and are attributable to pipeline and well connection measurement variances. As a result, EPO is required each period to contribute cash to Mont Belvieu Caverns for net operational measurement losses and is entitled to receive distributions from Mont Belvieu Caverns for net operational measurement gains.   Mont Belvieu Caverns recorded operational measurement gains of $1.1 million and losses of $3.8 million during the three and nine months ended September 30, 2008, respectively. For the three and eight months ended September 30, 2007, Mont Belvieu Caverns recorded operational measurement losses of $0.9 million and gains of $3.2 million, respectively. Operational measurement gains and losses are a component of gross operating margin for the NGL Pipelines & Services business segment; however, the related cash distributions from and contributions to Mont Belvieu Caverns are eliminated in the preparation of our consolidated financial statements.

Omnibus Agreement. In February 2007, EPO entered into an Omnibus Agreement with Duncan Energy Partners that governs the following matters:

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indemnification by EPO of certain environmental liabilities, tax liabilities and right-of-way defects with respect to assets EPO contributed to Duncan Energy Partners in February 2007;

§ reimbursement by EPO of certain capital expenditures incurred by South Texas NGL and Mont Belvieu Caverns with respect to projects under construction at the time of Duncan Energy Partners' initial public offering;

§ a right of first refusal to EPO in Duncan Energy Partners' current and future subsidiaries and a right of first refusal on the material assets of such subsidiaries, other than sales of inventory and other assets in the ordinary course of business; and

§ a preemptive right with respect to equity securities issued by certain of Duncan Energy Partners' subsidiaries, other than as consideration in an acquisition or in connection with a loan or debt financing.

Neither EPO nor any of its affiliates are restricted under the Omnibus Agreement from competing against Duncan Energy Partners. As provided for in the EPCO ASA, EPO and its affiliates may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer Duncan Energy Partners the opportunity to acquire or construct such assets.

As noted previously, EPO indemnified Duncan Energy Partners for certain environmental liabilities, tax liabilities and right-of-way defects associated with the assets EPO contributed to Duncan Energy Partners in February 2007. These indemnifications terminate on February 5, 2010. There is an aggregate cap of $15.0 million on the amount of indemnity coverage and Duncan Energy Partners is not entitled to indemnification until the aggregate amount of claims it incurs exceeds $250 thousand. Environmental liabilities resulting from a change of law after February 5, 2007 are excluded from the indemnity. Duncan Energy Partners made no claims to EPO during the three and nine months ended September 30, 2008 in connection with these indemnity provisions.

Under the Omnibus Agreement, EPO agreed to make additional cash contributions to South Texas NGL and Mont Belvieu Caverns to fund 100% of project costs in excess of (i) the $28.6 million of estimated costs to complete the Phase II expansion of the DEP South Texas NGL Pipeline System and (ii) the $14.1 million of estimated costs for additional Mont Belvieu brine production capacity and above-ground storage reservoir projects. These projects were in progress at the time of Duncan Energy Partners' initial public offering. EPO made cash contributions of $32.5 million under the Omnibus Agreement to the subsidiaries of Duncan Energy Partners during the nine months ended September 30, 2008. This amount was primarily contributed to South Texas NGL to fund costs of its Phase II pipeline project. We expect EPO to make contributions of approximately $2.1 million during the remainder of 2008 in satisfaction of its project funding obligations under the Omnibus Agreement.

EPO will not receive an increased allocation of earnings or cash flows as a result of these contributions to South Texas NGL and Mont Belvieu Caverns. EPO's payments under the Omnibus Agreement are accounted for as additional investments by EPO in the underlying companies and are subsequently eliminated in the preparation of our consolidated financial statements.

Mont Belvieu Caverns' LLC Agreement. The Mont Belvieu Caverns' LLC Agreement (the "Caverns LLC Agreement") states that if Duncan Energy Partners elects to not participate in certain projects of Mont Belvieu Caverns, then EPO is responsible for funding 100% of such projects. To the extent such non-participated projects generate identifiable incremental cash flows for Mont Belvieu Caverns in the future, the earnings and cash flows of Mont Belvieu Caverns will be adjusted to allocate such incremental amounts to EPO by special allocation or otherwise. Under the terms of the Caverns LLC Agreement, Duncan Energy Partners may elect to acquire a 66% share of these projects from EPO within 90 days of such projects being placed in-service. In November 2008, the Caverns LLC Agreement was amended to provide that EPO would prospectively receive a special allocation of 100% of the depreciation related to projects that it has fully funded.

EPO made cash contributions of $86.4 million under the Caverns LLC Agreement during the nine months ended September 30, 2008. These expenditures are associated with storage-related projects sponsored by EPO's NGL marketing activities and represent 100% of the costs of such projects to date. EPO expects that its NGL marketing activities will benefit from these projects. At present, Mont Belvieu Caverns is not expected to generate any identifiable incremental cash flows in connection with these projects; thus, the sharing ratio for Mont Belvieu Caverns is not expected to change from the current ratio of 66% for Duncan Energy Partners and 34% for EPO. However, as noted above, beginning in November 2008, EPO will receive a special allocation of depreciation related to these projects. We expect EPO to make $37.5 million of contributions to Mont Belvieu Caverns in connection with these construction projects during the remainder of 2008 through the first quarter of 2009. The constructed assets are the property of Mont Belvieu Caverns.

EPO's payments under the Caverns LLC Agreement are accounted for as additional investments by EPO in Mont Belvieu Caverns and are subsequently eliminated in the preparation of our consolidated financial statements.

Relationship with Energy Transfer Equity

Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity and its general partner in May 2007. As a result, Energy Transfer Equity and its consolidated subsidiaries became related parties to our consolidated businesses.

For the three and nine months ended September 30, 2008, we recorded $99.6 million and $413.0 million of revenues, respectively, from Energy Transfer Partners, L.P. ("ETP"), primarily from our NGL marketing activities. For the three and five months ended September 30, 2007, we recorded $79.0 million and $ 121.5 million, respectively, of revenues from ETP. We incurred $56.5 million and $134.4 million in operating costs and expenses for the three and nine months ended September 30, 2008, respectively, that were paid to ETP. For the three and five months ended September 30, 2007, we incurred $2.6 million and $8.4 million, respectively, in operating costs and expenses. We have a long-term revenue generating contract with Titan Energy Partners, L.P. ("Titan"), a consolidated subsidiary of ETP. Titan purchases substantially all of its propane requirements from us. We and Energy Transfer Company ("ETC OLP") transport natural gas on each other's systems and share operating expenses on certain pipelines. ETC OLP also sells natural gas to us.

Relationships with Unconsolidated Affiliates

Our significant related party revenue and expense transactions with unconsolidated affiliates consist of the sale of natural gas to Evangeline and the purchase of NGL storage, transportation and fractionation services from Promix. In addition, we sell natural gas to Promix and process natural gas at VESCO. For additional information regarding our unconsolidated affiliates, see Note 7.

See "Relationship with TEPPCO" within this Note 13 for a description of ongoing transactions involving our Jonah and TOPS joint ventures with TEPPCO.

Note 14. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the weighted-average number of distribution-bearing units outstanding during a period. Diluted earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the sum of (i) the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit); (ii) the weighted-average number of performance-based phantom units outstanding during a period; and (iii) 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, restricted units, phantom 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 value during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

The amount of net income or loss allocated to limited partner interests is net of our general partner's share of such earnings. The following table presents the allocation of net income to EPGP for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Net income	$ 203,081	$ 117,606	$ 725,960	$ 371,805
Less incentive earnings allocations to EPGP	(32,035)	(27,394)	(92,803)	(78,964)
Net income available after incentive earnings allocation	171,046	90,212	633,157	292,841
Multiplied by EPGP ownership interest	2.0%	2.0%	2.0%	2.0%
Standard earnings allocation to EPGP	$ 3,421	$ 1,804	$ 12,663	$ 5,857
Incentive earnings allocation to EPGP	$ 32,035	$ 27,394	$ 92,803	$ 78,964
Standard earnings allocation to EPGP	3,421	1,804	12,663	5,857
Net income available to EPGP	$ 35,456	$ 29,198	$ 105,466	$ 84,821

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,	
	2008	2007	2008	2007
Net income	$ 203,081	$ 117,606	$ 725,960	$ 371,805
Net income available to EPGP	(35,456)	(29,198)	(105,466)	(84,821)
Net income available to limited partners	$ 167,625	$ 88,408	$ 620,494	$ 286,984
BASIC EARNINGS PER UNIT				
Numerator				
Income before EPGP earnings allocation	$ 203,081	$ 117,606	$ 725,960	$ 371,805
Net income available to EPGP	(35,456)	(29,198)	(105,466)	(84,821)
Net income available to limited partners	$ 167,625	$ 88,408	$ 620,494	$ 286,984
Denominator				
Common units	435,313	432,805	434,629	432,221
Time-vested restricted units	2,261	1,645	1,941	1,364
Total	437,574	434,450	436,570	433,585
Basic earnings per unit				
Income before EPGP earnings allocation	$ 0.46	$ 0.27	$ 1.66	$ 0.86
Net income available to EPGP	(0.08)	(0.07)	(0.24)	(0.20)
Net income available to limited partners	$ 0.38	$ 0.20	$ 1.42	$ 0.66
DILUTED EARNINGS PER UNIT				
Numerator				
Income before EPGP earnings allocation	$ 203,081	$ 117,606	$ 725,960	$ 371,805
Net income available to EPGP	(35,456)	(29,198)	(105,466)	(84,821)
Net income available to limited partners	$ 167,625	$ 88,408	$ 620,494	$ 286,984
Denominator				
Common units	435,313	432,805	434,629	432,221
Time-vested restricted units	2,261	1,645	1,941	1,364
Performance-based restricted units	3	9	7	9
Incremental option units	201	354	287	480
Total	437,778	434,813	436,864	434,074

Diluted earnings per unit								
Income before EPGP earnings allocation	$	0.46	$	0.27	$	1.66	$	0.86
Net income available to EPGP		(0.08)		(0.07)		(0.24)		(0.20)
Net income available to limited partners	$	0.38	$	0.20	$	1.42	$	0.66

Note 15. Commitments and Contingencies

Litigation

On occasion, we or our unconsolidated affiliates are named as a defendant in litigation relating to our normal business activities, including regulatory and environmental matters. Although we are insured against various business risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings as a result of our ordinary business activities. We are unaware of any significant litigation, pending or threatened, that could have a significant adverse effect on our financial position, results of operations or cash flows.

On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of New Castle County in the State of Delaware, in his individual capacity, as a putative class action on behalf of other unitholders of TEPPCO, and derivatively on behalf of TEPPCO, concerning, among other things, certain transactions involving TEPPCO and us or our affiliates. Mr. Brinkerhoff filed an amended complaint on July 12, 2007. The complaint names as defendants (i) TEPPCO, certain of its current and former directors, and certain of its affiliates; (ii) us and certain of our affiliates; (iii) EPCO; and (iv) Dan L. Duncan.

The amended complaint alleges, among other things, that the defendants caused TEPPCO to enter into certain transactions that were unfair to TEPPCO or otherwise unfairly favored Enterprise Products Partners or its affiliates over TEPPCO. These transactions are alleged to include: (i) the joint venture to further expand the Jonah system entered into by TEPPCO and Enterprise Products Partners in August 2006; (ii) the sale by TEPPCO of its Pioneer natural gas processing plant to Enterprise Products Partners in March 2006; and (iii) certain amendments to TEPPCO's partnership agreement, including a reduction in the maximum tier of TEPPCO's incentive distribution rights in exchange for TEPPCO common units. The amended complaint seeks (i) rescission of the amendments to TEPPCO's partnership agreement; (ii) damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the amended complaint; and (iii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts. We believe this lawsuit is without merit and intend to vigorously defend against it. See Note 13 for additional information regarding our relationship with TEPPCO.

On February 14, 2007, EPO received a letter from the Environment and Natural Resources Division ("ENRD") of the U.S. Department of Justice ("DOJ") related to an ammonia release in Kingman County, Kansas on October 27, 2004 from a pressurized anhydrous ammonia pipeline owned by a third party, Magellan Ammonia Pipeline, L.P. ("Magellan") and a previous release of ammonia on September 27, 2004 from the same pipeline. EPO was the operator of this pipeline until July 1, 2008. The ENRD has indicated that it may pursue civil damages against EPO and Magellan as a result of these incidents. Based on this correspondence from the ENRD, the statutory maximum amount of civil fines that could be assessed against EPO and Magellan is up to $17.4 million in the aggregate. EPO is cooperating with the DOJ and is hopeful that an expeditious resolution of this civil matter acceptable to all parties will be reached in the near future. Magellan has agreed to indemnify EPO for the civil matter. At this time, we do not believe that a final resolution of the civil claims by the ENRD will have a material impact on our consolidated financial position, results of operations or cash flows.

On October 25, 2006, a rupture in the Magellan Ammonia Pipeline resulted in the release of ammonia near Clay Center, Kansas. The pipeline has been repaired and environmental remediation tasks related to this incident have been completed. At this time, we do not believe that this incident will have a material impact on our consolidated financial position, results of operations or cash flows.

Several lawsuits have been filed by municipalities and other water suppliers against a number of manufacturers of reformulated gasoline containing methyl tertiary butyl ether. In general, such suits have not named manufacturers of this product as defendants, and there have been no such lawsuits filed against our subsidiary that owns an octane-additive production facility. It is possible, however, that former manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits.

The Attorney General of Colorado on behalf of the Colorado Department of Public Health and Environment filed suit against us and others on April 15, 2008 in connection with the construction of a pipeline near Parachute, Colorado. The State sought a temporary restraining order and an injunction to halt construction activities since it alleged that the defendants failed to install measures to minimize damage to the environment and to follow requirements for the pipeline's stormwater permit and appropriate stormwater plan. The State's complaint also seeks penalties for the above alleged failures. Defendants and the State agreed to certain stipulations that, among other things, require us to install specified environmental protection measures in the disturbed pipeline right-of-way to comply with regulations. We have complied with the stipulations and the State has dismissed the portions of the complaint seeking the temporary restraining order and injunction. The State has not yet assessed penalties and we are unable to predict the amount of penalties that may be assessed. At this time, we do not believe that this incident will have a material impact on our consolidated financial position, results of operations or cash flows.

Contractual Obligations

Operating Lease Obligations. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Our significant lease agreements involve (i) the lease of underground caverns for the storage of natural gas and NGLs, (ii) leased office space with affiliates of EPCO, (iii) a railcar unloading terminal in Mont Belvieu, Texas and (iv) land held pursuant to right-of-way agreements. In general, our material lease agreements have original terms that range from two to 28 years and include renewal options that could extend the agreements for up to an additional 20 years. Lease expense is charged to operating costs and expenses on a straight-line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred.

Lease and rental expense was $8.5 million and $9.0 million during the three months ended September 30, 2008 and 2007, respectively. For the nine months ended September 30, 2008 and 2007, lease and rental expense was $26.9 million and $28.9 million, respectively. There have been no material changes in our operating lease commitments since December 31, 2007.

Scheduled Maturities of Long-Term Debt. With the exception of the issuance of Senior Notes M and N by EPO in April 2008 and routine fluctuations in the balance of our consolidated revolving credit facilities, there have been no significant changes in our consolidated scheduled maturities of long-term debt since those reported in our Annual Report on Form 10-K for the year ended December 31, 2007. See Note 10 for additional information regarding the issuance of senior notes by EPO.

Purchase Obligations. There have been no material changes in our consolidated purchase obligations since December 31, 2007, except for commitments associated with two long-term natural gas purchase agreements and certain pipeline capacity reservation agreements that we executed in 2008 to support our natural gas marketing activities. The following table presents our estimated purchase commitments (in terms of volumes and cost) under these new agreements for the periods indicated:

		Payment or Settlement due by Period			
	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Product purchase commitments:					
Estimated payment obligations:					
Natural gas	$ 5,707,213	$ 261,703	$ 985,430	$ 1,232,670	$ 3,227,410
Underlying volume commitment:					
	927,765	45,360	158,775	199,505	524,125

Natural gas (in billion British thermal units)										
Service payment commitments										
for pipeline capacity reservation	$	157,633	$	2,730	$	27,414	$	30,074	$	97,415

Estimated future payment obligations for natural gas shown in the preceding table are based on the contractual price under each contract for purchases made at September 30, 2008 applied to all future volume commitments. Actual future payment obligations under these natural gas purchase agreements will vary depending on market prices at the time of delivery.

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of September 30, 2008, claims against us totaled approximately $3.0 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated. However, in our opinion, the likelihood of a material adverse outcome related to such disputes is remote. Accordingly, accruals for loss contingencies related to these matters, if any, that might result from the resolution of such disputes have not been reflected in our consolidated financial statements.

Note 16. Significant Risks and Uncertainties – Weather-Related Risks

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which are customary and sufficient for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance will not cover every type of interruption that might occur. If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient to reimburse us for our repair costs or lost income. Any event that interrupts the revenues generated by our consolidated operations, or which causes us to make significant 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 windstorm events such as hurricanes and tropical storms, EPCO's deductible for onshore physical damage is $10.0 million per storm. For offshore assets, the windstorm deductible is $10.0 million per storm plus a one-time $15.0 million aggregate deductible per policy period. For non-windstorm events, EPCO's deductible for onshore and offshore physical damage is $5.0 million per occurrence. In meeting the deductible amounts, property damage costs are aggregated for EPCO and its affiliates, including us. Accordingly, our exposure with respect to the deductibles may be equal to or less than the stated amounts depending on whether other EPCO or affiliate assets are also affected by an event.

To qualify for business interruption coverage in connection with a windstorm event, covered assets must be out-of-service in excess of 60 days for onshore assets and 75 days for offshore assets. To qualify for business interruption coverage in connection with a non-windstorm event, covered onshore and offshore assets must be out-of-service in excess of 60 days.

Hurricanes Gustav and Ike

In the third quarter of 2008, our onshore and offshore facilities located along the Gulf Coast of Texas and Louisiana were adversely impacted by Hurricanes Gustav and Ike. The disruptions in natural gas, NGL and crude oil production caused by these storms resulted in decreased volumes for some of our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which, in turn, caused a decrease in gross operating margin from these operations. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, we expensed a combined $46.0 million of repair costs for property damage in connection with these two storms. We expect to file property damage insurance claims to the extent repair costs exceed this amount. Due to the recent nature of these storms, we are still evaluating the total cost of repairs and the potential for business interruption claims on certain assets.

Pre-2008 Hurricanes (Katrina, Rita, et al)

The following table summarizes the proceeds we received from business interruption and property damage insurance claims with respect to certain named storms for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Business interruption proceeds:				
Hurricane Ivan	$ --	$ --	$ --	$ 377
Hurricane Katrina	--	1,301	501	14,500
Hurricane Rita	--	743	662	9,000
Other	--	--	--	996
Total proceeds	--	2,044	1,163	24,873
Property damage proceeds:				
Hurricane Ivan	--	--	--	1,273
Hurricane Katrina	2,495	--	9,404	6,563
Hurricane Rita	--	--	2,678	--
Other	--	--	--	184
Total proceeds	2,495	--	12,082	8,020
Total	$ 2,495	$ 2,044	$ 13,245	$ 32,893

At September 30, 2008, we have $30.8 million of estimated property damage claims outstanding related to these storms that we believe are probable of collection through 2009. To the extent we estimate the dollar value of such damages, please be aware that a change in our estimates may occur as additional information becomes available.

Note 17. Supplemental Cash Flow Information

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 production well tie-ins. We received $21.2 million and $52.5 million as contributions in aid of our construction costs during the nine months ended September 30, 2008 and 2007, respectively.

We determine net cash flows provided by operating activities using the indirect method, which adjusts net income for items that did not affect cash. Under GAAP, we use the accrual basis of accounting to determine net income. This basis of accounting requires that we record revenue when earned and expenses when incurred. Earned revenues may include credit sales that have not been collected in cash and expenses incurred that may not have been paid in cash. The extent to which changes in operating accounts influence net cash flows provided by operating activities generally depends on the following:

§ The timing of cash receipts from revenue transactions and cash payments for expense transactions near the end of each reporting period. For example, if significant cash receipts are posted on the last day of the current reporting period, but subsequent payments on expense invoices are made on the first day of the next reporting period, net cash flows provided by operating activities will reflect an increase in the current reporting period that will be reduced as payments are made in the next period. We employ prudent cash management practices and monitor our daily cash requirements to meet our ongoing liquidity needs.

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If commodity or other prices increase between reporting periods, changes in accounts receivable and accounts payable and accrued expenses may appear larger than in previous periods; however, overall levels of receivables and payables may still reflect normal ranges. From a receivables standpoint, we monitor the amount of credit extended to customers.

§ Additions to inventory for forward sales transactions or other reasons or increased expenditures for prepaid items would be reflected as a use of cash and reduce overall cash provided by operating activities in a given reporting period. As these assets are charged to expense in subsequent periods, the expense amount is reflected as a positive change in operating accounts; however, there is no impact on operating cash flows.

In addition to the adjustments noted above, non-cash charges in the income statement are added back to net income and non-cash credits are deducted to compute net cash flows provided by operating activities. Examples of non-cash charges include depreciation and amortization.

The net effect of changes in operating assets and liabilities is as follows for the periods indicated:

	For the Nine Months Ended September 30, 2008	2007
Decrease (increase) in:		
Accounts and notes receivable	$ 84,900	$ (281,949)
Inventories	(299,124)	(170,610)
Prepaid and other current assets	(43,928)	(41,171)
Other assets	24,236	4,719
Increase (decrease) in:		
Accounts payable	(5,951)	61,106
Accrued product payable	14,192	354,508
Accrued expenses	27,177	152,534
Accrued interest	(29,009)	10,020
Other current liabilities	7,691	26,110
Other long-term liabilities	(8,581)	(4,995)
Net effect of changes in operating accounts	$ (228,397)	$ 110,272

Note 18. Condensed Financial Information of EPO

EPO conducts substantially all of our business. Currently, we have no independent operations and no material assets outside those of EPO. EPO consolidates the financial statements of Duncan Energy Partners with those of its own.

Enterprise Products Partners L.P. guarantees the debt obligations of EPO, with the exception of the Dixie revolving credit facility and the Duncan Energy Partners' revolving credit facility. 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. See Note 10 for additional information regarding our consolidated debt obligations.

The reconciling items between our consolidated financial statements and those of EPO are insignificant. The following table presents condensed consolidated statements of operations data for EPO for the periods indicated:

	For the Three Months Ended September 30, 2008	2007	For the Nine Months Ended September 30, 2008	2007
Revenues	$ 6,297,902	$ 4,111,996	$ 18,322,052	$ 11,647,656
Costs and expenses	5,993,391	3,917,172	17,308,464	11,046,151
Equity in earnings of unconsolidated affiliates	14,876	13,960	48,037	13,928
Operating income	319,387	208,784	1,061,625	615,433
Other expense, net	(101,481)	(84,001)	(287,679)	(215,088)

Income before provision for income taxes and minority interest	217,906	124,783	773,946	400,345
Provision for income taxes	(6,609)	(2,072)	(17,193)	(9,006)
Income before minority interest	211,297	122,711	756,753	391,339
Minority interest	(7,998)	(7,804)	(29,454)	(19,325)
Net income	$ 203,299	$ 114,907	$ 727,299	$ 372,014

The following table presents condensed consolidated balance sheet data for EPO at the dates indicated:

	September 30, 2008	December 31, 2007
ASSETS		
Current assets	$ 2,993,491	$ 2,545,297
Property, plant and equipment, net	12,693,619	11,587,264
Investments in and advances to unconsolidated affiliates, net	917,193	858,339
Intangible assets, net	866,313	917,000
Goodwill	616,996	591,652
Deferred tax asset	2,320	3,113
Other assets	69,067	112,345
Total	$ 18,158,999	$ 16,615,010
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities	$ 3,170,816	$ 3,044,002
Long-term debt	8,458,195	6,906,145
Other long-term liabilities	89,263	95,112
Minority interest	422,499	439,854
Members' equity	6,018,226	6,129,897
Total	$ 18,158,999	$ 16,615,010
Total EPO debt obligations guaranteed by Enterprise Products Partners L.P.	$ 8,212,201	$ 6,686,500

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

For the three and nine months ended September 30, 2008 and 2007.

The following information should be read in conjunction with our Unaudited Condensed Consolidated Financial Statements and our accompanying notes included under Item 1 of this Quarterly Report on Form 10-Q and with the information contained within our Annual Report on Form 10-K for the year ended December 31, 2007. Our discussion and analysis includes the following:

§ Cautionary Note Regarding Forward-Looking Statements.

§ Significant Relationships Referenced in this Discussion and Analysis.

§ Overview of Business.

§ Recent Developments – Discusses significant developments since December 31, 2007.

§ Results of Operations – Discusses material period-to-period variances in our Unaudited Condensed Statements of Consolidated Operations.

§ Liquidity and Capital Resources – Addresses available sources of liquidity and capital resources and includes a discussion of our capital spending program.

§ Overview of Critical Accounting Policies and Estimates.

§ Other Items – Includes information related to contractual obligations, off-balance sheet arrangements, related party transactions, recent accounting pronouncements and similar disclosures.

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

Our financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP").

Cautionary Note Regarding Forward-Looking Statements

This discussion contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "forecast," "intend," "could," "should," "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 such 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. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Part I, Item 1A, “Risk Factors,” included in our Annual Report on Form 10-K for 2007. 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.

Significant Relationships Referenced in this Discussion and Analysis

Unless the context requires otherwise, references to "we," "us," "our" 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 Products Partners.

References to "Duncan Energy Partners" mean Duncan Energy Partners L.P., which is a consolidated subsidiary of EPO. Duncan Energy Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "DEP." References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

References to "EPGP" mean Enterprise Products GP, LLC, which is our general partner.

References to "Enterprise GP Holdings" mean Enterprise GP Holdings L.P., a publicly traded affiliate, the units of which are listed on the NYSE under the ticker symbol "EPE." Enterprise GP Holdings owns EPGP. References to "EPE Holdings" mean EPE Holdings, LLC, which is the general partner of Enterprise GP Holdings.

References to "TEPPCO" mean TEPPCO Partners, L.P., a publicly traded affiliate, the common units of which are listed on the NYSE under the ticker symbol "TPP." References to "TEPPCO GP" refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by Enterprise GP Holdings.

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"). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." The general partner of Energy Transfer Equity is LE GP, LLC ("LE GP"). On May 7, 2007, Enterprise GP Holdings acquired non-controlling interests in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

References to "Employee Partnerships" mean EPE Unit L.P. ("EPE Unit I"), EPE Unit II, L.P. ("EPE Unit II"), EPE Unit III, L.P. ("EPE Unit III") and Enterprise Unit L.P. ("Enterprise Unit"), collectively, which are private company affiliates of EPCO, Inc.

References to "EPCO" mean EPCO, Inc. and its wholly-owned private company affiliates, which are related parties to all of the foregoing named entities.

Overview of Business

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids ("NGLs"), crude oil and certain petrochemicals. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the NYSE under the ticker symbol "EPD."

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

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consumers and international markets. We have four reportable business segments: NGL Pipelines & Services; Onshore Natural Gas Pipelines & Services; Offshore Pipelines & Services; and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We conduct substantially all of our business through EPO. We are owned 98% by our limited partners and 2% by our general partner, EPGP. EPGP is owned 100% by Enterprise GP Holdings. We, EPO, Duncan Energy Partners, DEP GP, EPGP, Enterprise GP Holdings, EPE Holdings, TEPPCO and TEPPCO GP are affiliates and under the common control of Dan L. Duncan, the Group Co-Chairman and the controlling shareholder of EPCO.

Recent Developments

The following information highlights our significant developments since January 1, 2008 through the date of this filing.

Texas Offshore Port System Joint Venture

In August 2008, we, together with TEPPCO and Oiltanking Holding Americas, Inc. (“Oiltanking”), announced the formation of a joint venture to design, construct, operate and own a Texas offshore crude oil port and related pipeline and storage infrastructure that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. Demand for such projects is being driven by planned and expected refinery expansions along the Gulf Coast, expected increases in shipping traffic and operating limitations of regional ship channels.

The joint venture’s primary project, referred to as “TOPS,” includes (i) an offshore port (which will be located approximately 36 miles from Freeport, Texas), (ii) an onshore storage facility with approximately 3.9 million barrels of crude oil storage capacity, and (iii) an 85-mile crude oil pipeline system having a transportation capacity of up to 1.8 million barrels per day, that will extend from the offshore port to a Texas City, Texas storage facility. TOPS is expected to begin service as early as the fourth quarter of 2010. The joint venture’s second and complementary project, referred to as the Port Arthur Crude Oil Express (or “PACE”) will transport crude oil from Texas City, including crude oil from TOPS, and will consist of a 75-mile pipeline and 1.2 million barrels of crude oil storage capacity in the Port Arthur, Texas area. PACE is expected to begin service as early as the third quarter of 2010. Development of the TOPS and PACE projects is supported by long-term contracts with affiliates of Motiva Enterprises LLC and Exxon Mobil Corporation, which have committed a combined 725,000 barrels per day of crude oil to the projects.

We, TEPPCO and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such capital expenditures occurring in 2009 and 2010. We and TEPPCO have each guaranteed up to approximately $700.0 million of the capital contribution obligations of our respective subsidiary partners in the joint venture. As of September 30, 2008, our investment in TOPS was $2.4 million.

Acquisition of Remaining Interest in Dixie

In August 2008, we acquired the remaining 25.8% ownership interest in Dixie Pipeline Company (“Dixie”) for $57.1 million. As a result of this transaction, we own 100% of Dixie, which owns a 1,300-mile pipeline system that delivers NGLs (primarily propane and other chemical feedstocks) to customers along the U.S. Gulf Coast and southeastern United States.

Reorganization of Commercial Management Team

In July 2008, Mr. A. J. Teague, Executive Vice President, was elected as a Director to the boards of both our general partner and that of Duncan Energy Partners and as Chief Commercial Officer responsible for managing all of the commercial activities of the two partnerships. In connection with Mr. Teague's appointment as Chief Commercial Officer, certain members of our senior management team were realigned to report to Mr. Teague. Mr. Teague will continue to report to Michael A. Creel, President and Chief Executive Officer of Enterprise Products Partners.

Independence Trail and Hub Resume Operations

In April 2008, production at the Independence Hub natural gas platform was shut-in due to a leak in the flex-joint assembly where the Independence Trail export pipeline connects to the platform. In July 2008, repairs were completed and the Independence Hub platform and Trail pipeline returned to operation. Our Independence Trail export pipeline recorded $17.0 million of expense associated with the flex-joint repairs. We have submitted a claim with our insurance carriers regarding the flex-joint repair costs. To the extent that we receive cash proceeds from this claim in the future, such amounts would be recorded as income in the period of receipt.

EPO Issues $1.10 Billion of Senior Notes

In April 2008, EPO sold $400.0 million in principal amount of 5.65% fixed-rate, unsecured senior notes due April 2013 ("Senior Notes M") and $700.0 million in principal amount of 6.50% fixed-rate, unsecured senior notes due January 2019 ("Senior Notes N"). Net proceeds from this offering were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility. For additional information regarding this issuance of debt, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.

Duncan Energy Partners' Shelf Registration Statement

In March 2008, Duncan Energy Partners filed a universal shelf registration statement with the U.S. Securities and Exchange Commission ("SEC") that authorized its issuance of up to $1.00 billion in debt and equity securities. Duncan Energy Partners has not issued any securities under this registration statement through November 3, 2008.

Our Pioneer Cryogenic Natural Gas Processing Facility Commences Operations

In February 2008, we commenced operations at our recently completed Pioneer cryogenic natural gas processing facility. Located near the Opal Hub in southwestern Wyoming, this new facility is designed to process up to 750 MMcf/d of natural gas and extract as much as 30 MBPD of NGLs. We intend to maintain the operational capability of our Pioneer silica gel natural gas processing plant, which is located adjacent to the Pioneer cryogenic plant, as a back-up to provide producers with additional assurance of our processing capability at the complex. NGLs extracted at our Pioneer complex are transported on our Mid-America Pipeline System and ultimately to our Hobbs and Mont Belvieu NGL fractionators.

In late March 2008, operations at our Pioneer cryogenic natural gas processing facility were temporarily suspended following a release of natural gas and subsequent fire. No injuries resulted from the incident, which was restricted to a small area within the plant. The facility resumed operations in April 2008.

Results of Operations

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

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 senior 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 as an alternative to GAAP operating income.

We define total segment gross operating margin as consolidated operating income before (i) depreciation, amortization and accretion expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses from asset sales and related transactions; and (iv) general and administrative costs. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of changes in accounting principle. 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 intersegment and intrasegment transactions. Intercompany accounts and transactions are eliminated in consolidation.

We include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers and/or suppliers. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our consolidated gross operating margin amounts include the gross operating margin amounts of Duncan Energy Partners on a 100% basis. Volumetric data associated with the operations of Duncan Energy Partners are also included on a 100% basis in our consolidated statistical data.

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.

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Selected Price and Volumetric Data

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

	Natural Gas, $/MMBtu (1)	Crude Oil, $/barrel (2)	Ethane, $/gallon (1)	Propane, $/gallon (1)	Normal Butane, $/gallon (1)	Isobutane, $/gallon (1)	Natural Gasoline, $/gallon (1)	Polymer Grade Propylene, $/pound (1)	Refinery Grade Propylene, $/pound (1)
2007									
1st Quarter	$6.77	$58.02	$0.59	$0.97	$1.13	$1.22	$1.37	$0.45	$0.40
2nd Quarter	$7.55	$64.97	$0.72	$1.13	$1.33	$1.45	$1.65	$0.51	$0.46
3rd Quarter	$6.16	$75.48	$0.82	$1.23	$1.44	$1.49	$1.68	$0.52	$0.46
4th Quarter	$6.97	$90.75	$1.04	$1.51	$1.79	$1.80	$2.01	$0.59	$0.54
2007 Averages	$6.86	$72.30	$0.79	$1.21	$1.42	$1.49	$1.68	$0.52	$0.47
2008									
1st Quarter	$8.03	$97.91	$1.01	$1.47	$1.80	$1.87	$2.12	$0.61	$0.54
2nd Quarter	$10.94	$123.88	$1.05	$1.70	$2.05	$2.08	$2.64	$0.70	$0.67
3rd Quarter	$10.25	$118.01	$1.09	$1.68	$1.97	$1.99	$2.52	$0.78	$0.66
2008 Averages	$9.74	$113.27	$1.05	$1.62	$1.94	$1.98	$2.43	$0.70	$0.62

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including Oil Price Information Service (“OPIS”) and Chemical Market Associates, Inc. (“CMAI”). Natural gas price is representative of Henry-Hub I-FERC. NGL prices are representative of Mont Belvieu Non-TET pricing. Refinery grade propylene represents a weighted-average of CMAI spot prices. Polymer-grade propylene represents average CMAI contract pricing.
(2) Crude oil price is representative of an index price for West Texas Intermediate.

The following table presents our significant average throughput, production and processing volumetric data. 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 include volumes for newly constructed assets since the dates such assets were placed into service and for recently purchased assets since the date of acquisition.

	For the Three Months Ended September 30, 2008	For the Three Months Ended September 30, 2007	For the Nine Months Ended September 30, 2008	For the Nine Months Ended September 30, 2007
NGL Pipelines & Services, net:				
NGL transportation volumes (MBPD)	1,758	1,575	1,788	1,626
NGL fractionation volumes (MBPD)	413	371	424	379
Equity NGL production (MBPD)	109	64	108	67
Fee-based natural gas processing (MMcf/d)	2,064	2,269	2,469	2,358
Onshore Natural Gas Pipelines & Services, net:				

Natural gas transportation volumes (BBtus/d)	7,562	6,597	7,309	6,576
Offshore Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	1,244	1,271	1,449	1,407
Crude oil transportation volumes (MBPD)	147	163	190	164
Platform gas processing (MMcf/d)	583	246	588	265
Platform oil processing (MBPD)	14	24	19	24
Petrochemical Services, net:				
Butane isomerization volumes (MBPD)	71	96	85	93
Propylene fractionation volumes (MBPD)	58	68	59	69
Octane additive production volumes (MBPD)	8	11	9	9
Petrochemical transportation volumes (MBPD)	95	108	110	104
Total, net:				
NGL, crude oil and petrochemical transportation volumes (MBPD)	2,000	1,846	2,088	1,894
Natural gas transportation volumes (BBtus/d)	8,806	7,868	8,758	7,983
Equivalent transportation volumes (MBPD) (1)	4,317	3,917	4,393	3,995

(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 indicated (dollars in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Revenues	$ 6,297,902	$ 4,111,996	$ 18,322,052	$ 11,647,656
Operating costs and expenses	5,971,942	3,896,411	17,243,070	10,981,562
General and administrative costs	21,720	18,715	66,901	66,706
Equity in earnings of unconsolidated affiliates	14,876	13,960	48,037	13,928
Operating income	319,116	210,830	1,060,118	613,316
Interest expense	102,657	85,075	290,412	219,708
Net income	203,081	117,606	725,960	371,805

Our gross operating margin by segment and in total is as follows for the periods indicated (dollars in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Gross operating margin by segment:				
NGL Pipelines & Services	$ 336,054	$ 190,209	$ 943,445	$ 589,708
Onshore Natural Gas Pipelines & Services	88,160	75,424	321,237	235,102
Offshore Pipelines & Services	17,465	46,676	134,353	97,429
Petrochemical Services	37,243	51,412	136,465	139,329
Total segment gross operating margin	$ 478,922	$ 363,721	$ 1,535,500	$ 1,061,568

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before provision for income taxes and minority interest, see “Other Items – Non-GAAP reconciliations” included within this Item 2.

The following table summarizes the contribution to consolidated revenues from the sale of NGL, natural gas and petrochemical products during the periods indicated (dollars in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
NGL Pipelines & Services:				
Sale of NGL products	$ 4,271,467	$ 2,837,465	$ 12,550,220	$ 7,952,147
Percent of consolidated revenues	68%	69%	68%	68%
Onshore Natural Gas Pipelines & Services:				
Sale of natural gas	851,748	406,482	2,407,930	1,190,235
Percent of consolidated revenues	14%	10%	13%	10%
Petrochemical Services:				
Sale of petrochemical products	708,745	444,670	1,928,840	1,268,731
Percent of consolidated revenues	11%	11%	11%	11%

As noted in the following section, changes in our revenues and costs and expenses period-to-period are explained in part by changes in energy commodity prices.

Comparison of Three Months Ended September 30, 2008 with
Three Months Ended September 30, 2007

Revenues for the third quarter of 2008 were $6.30 billion compared to $4.11 billion for the third quarter of 2007. The $2.19 billion quarter-to-quarter increase in consolidated revenues is primarily due to higher energy commodity sales volumes and prices during the third quarter of 2008 relative to the third quarter of 2007. These factors accounted for $1.89 billion of the quarter-to-quarter increase in consolidated revenues associated with our NGL, natural gas and petrochemical marketing activities. Consolidated revenues increased $270.1 million quarter-to-quarter due to the addition of revenues from newly constructed assets, principally our Meeker and Pioneer natural gas processing plants.

Operating costs and expenses were $5.97 billion for the third quarter of 2008 versus $3.90 billion for the third quarter of 2007. The $2.07 billion quarter-to-quarter increase in consolidated operating costs and expenses is primarily due to higher cost of sales associated with our marketing activities. The cost of sales of our marketing activities increased $1.61 billion quarter-to-quarter primarily due to higher energy commodity sales volumes and prices. Likewise, the operating costs and expenses of our natural gas processing plants increased $294.5 million quarter-to-quarter primarily due to higher energy commodity prices. Consolidated operating costs and expenses attributable to newly constructed assets increased $92.6 million quarter-to-quarter. General and administrative costs increased $3.0 million quarter-to-quarter.

Changes in our revenues and costs and expenses quarter-to-quarter are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.68 per gallon during the third quarter of 2008 versus $1.21 per gallon during the third quarter of 2007. 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) averaged $10.25 per MMBtu during the third quarter of 2008 versus $6.16 per MMBtu during the third quarter of 2007. See the table on page 55 for additional historical energy commodity pricing information.

Equity earnings from our unconsolidated affiliates were $14.9 million for the third quarter of 2008 compared to $14.0 million for the third quarter of 2007. Equity earnings from our investment in Jonah Gas Gathering Company ("Jonah") increased $2.9 million quarter-to-quarter. Equity earnings from our investment in Cameron Highway Oil Pipeline Company ("Cameron Highway") increased $1.9 million quarter-to-quarter due to higher transportation volumes. Collectively, equity earnings from our investments in Poseidon Oil Pipeline Company, L.L.C ("Poseidon") and Deepwater Gateway, L.L.C. ("Deepwater Gateway") decreased $4.1 million quarter-to-quarter as a result of downtime and upstream supply interruptions caused by Hurricanes Gustav and Ike during the third quarter of 2008.

Operating income for the third quarter of 2008 was $319.1 million compared to $210.8 million for the third quarter of 2007. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $108.3 million increase in operating income quarter-to-quarter.

Interest expense increased to $102.7 million for the third quarter of 2008 from $85.1 million for the third quarter of 2007. The $17.6 million quarter-to-quarter increase in interest expense is primarily due to our issuance of Senior Notes M and N in the second quarter of 2008 and Senior Notes L in the third quarter of 2007. Average debt principal outstanding during the third quarter of 2008 was $8.14 billion compared to $6.55 billion during the third quarter of 2007. Provision for income taxes increased $4.5 million quarter-to-quarter primarily due to higher expenses associated with the Texas Margin Tax.

As a result of items noted in the previous paragraphs, our consolidated net income increased $85.5 million quarter-to-quarter to $203.1 million for the third quarter of 2008 compared to $117.6 million for the third quarter of 2007.

In general, Hurricanes Gustav and Ike had an adverse effect across our operations in the Gulf of Mexico and along the U.S. Gulf Coast during the third quarter of 2008. Storm-related disruptions in natural gas, NGL and crude oil production in these regions resulted in reduced volumes available to our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which in turn caused a decrease in gross operating margin for certain operations. In addition, property damage caused by Hurricanes Gustav and Ike resulted in lower revenues due to facility downtime as well as higher operating costs and expenses at certain of our plants and pipelines. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, gross operating margin for the third quarter of 2008 includes $46.0 million of repair expenses for property damage sustained by our assets as a result of the hurricanes.

We estimate that gross operating margin was reduced by $43.0 million during the third quarter of 2008 due to the effects of Hurricanes Gustav and Ike as a result of supply interruptions and facility downtime. We currently estimate the effects of lost business attributable to Hurricanes Gustav and Ike to reduce gross operating margin for the fourth quarter of 2008 by $25.0 million to $35.0 million prior to any future recoveries under business interruption insurance. For more information regarding our insurance program and claims related to these storms, see "Other Items – Weather-related Risks" included within this Item 2.

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 $336.1 million for the third quarter of 2008 compared to $190.2 million for the third quarter of 2007. The $145.9 million quarter-to-quarter increase in segment gross operating margin is due to strong natural gas processing margins and NGL demand for petrochemical production as well as an increase in equity NGL production attributable to our Meeker and Pioneer natural gas processing facilities. The third quarter of 2007 includes $1.8 million of proceeds from business interruption insurance claims compared to none for the third quarter of 2008. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $237.6 million for the third quarter of 2008 compared to $96.1 million for the third quarter of 2007. Equity NGL production increased to 109 MBPD during the third quarter of 2008 from 64 MBPD during the third quarter of 2007. The $141.5 million quarter-to-quarter increase in gross operating margin is largely due to contributions from our Meeker and Pioneer cryogenic natural gas processing facilities, which commenced commercial operations during October 2007 and February 2008, respectively. These facilities contributed $97.8 million of the quarter-to-quarter increase in gross operating margin and produced 55 MBPD of equity NGLs during the third quarter of 2008. Gross operating margin from our NGL marketing activities increased $45.5 million quarter-to-quarter primarily due to higher NGL sales margins and volumes. Equity NGL production at the Meeker and Pioneer facilities contributed to the increase in NGL marketing sales volumes.

Collectively, gross operating margin from the remainder of this business decreased $1.8 million quarter-to-quarter. Higher natural gas processing margins in South Texas during the third quarter of 2008 relative to the third quarter of 2007 were more than offset by lower gross operating margin from our facilities in Southern Louisiana. Our natural gas processing plants in Louisiana were negatively affected by downtime and upstream supply interruptions as a result of Hurricanes Gustav and Ike in the third quarter of 2008. In addition, results for our natural gas processing plants in Southern Louisiana include $7.5 million of hurricane-related property damage repair expenses in the third quarter of 2008.

Gross operating margin from our NGL pipelines and related storage business was $72.5 million for the third quarter of 2008 compared to $71.2 million for the third quarter of 2007. Total NGL transportation volumes increased to 1,758 MBPD during the third quarter of 2008 from 1,575 MBPD during the third quarter of 2007. The $1.3 million quarter-to-quarter increase in gross operating margin from this business is primarily due to improved results from our Mid-America and Seminole Pipeline Systems and our NGL storage facility in Mont Belvieu, Texas. Gross operating margin from our Mid-America and Seminole Pipeline Systems increased $6.1 million quarter-to-quarter due to higher transportation volumes and an increase in the system-wide tariff. These pipeline systems contributed 138 MBPD of the quarter-to-quarter increase in NGL transportation volumes. Gross operating margin from our Mont Belvieu NGL storage facility increased $4.3 million as a result of higher revenues during the third quarter of 2008 relative to the third quarter of 2007.

Gross operating margin from the remainder of our NGL pipeline and storage assets decreased $9.1 million quarter-to-quarter attributable to (i) higher maintenance expenses on our Dixie Pipeline System and our NGL Export facility, (ii) higher pipeline integrity expenses on our Dixie Pipeline System and (iii) downtime and reduced volumes as a result of Hurricanes Gustav and Ike during the third quarter of 2008.

Gross operating margin from our Dixie Pipeline System and NGL Export facility decreased $4.0 million and $2.2 million quarter-to-quarter, respectively. In addition, results for our NGL pipelines and related storage business include $1.9 million of hurricane-related property damage repair expenses in the third quarter of 2008.

Gross operating margin from our NGL fractionation business was $25.9 million for the third quarter of 2008 compared to $21.1 million for the third quarter of 2007. Fractionation volumes increased from 371 MBPD during the third quarter of 2007 to 413 MBPD during the third quarter of 2008. The $4.8 million quarter-to-quarter increase in gross operating margin and 42 MBPD increase in fractionation volumes is largely attributable to our Hobbs fractionator, which became operational in August 2007. Gross operating margin from our Hobbs fractionator increased $9.3 million quarter-to-quarter on a 52 MBPD increase in NGL fractionation volumes. Collectively, gross operating margin from our other NGL fractionators decreased $4.5 million quarter-to-quarter primarily due to downtime and lower volumes at our Norco, Mont Belvieu and Baton Rouge fractionators as well as a combined $0.5 million of hurricane- related property damage repair expenses in the third quarter of 2008.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $88.2 million for the third quarter of 2008 compared to $75.4 million for the third quarter of 2007. Our onshore natural gas transportation volumes were 7,562 BBtus/d during the third quarter of 2008 compared to 6,597 BBtus/d during the third quarter of 2007. Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business was $77.4 million in the third quarter of 2008 compared to $67.8 million in the third quarter of 2007. The $9.6 million quarter-to-quarter increase in gross operating margin from this business is largely due to improved results from our San Juan Gathering System. Gross operating margin on our San Juan Gathering System increased $16.7 million quarter-to-quarter due to higher revenues from transportation fees indexed to natural gas prices and condensate sales. Collectively, gross operating margin from the remainder of our natural gas pipelines increased $10.5 million quarter-to-quarter primarily due to (i) higher transportation volumes and fees on our Texas Intrastate System, (ii) an increase in volumes on our Piceance Creek Gathering System and (iii) increased equity earnings from our investment in Jonah. Results from our natural gas pipelines were partially offset by a $17.6 million quarter-to-quarter decrease in gross operating margin associated with our natural gas marketing activities primarily due to non-cash mark-to-market related charges that are expected to be recouped in cash in future periods extending through 2009.

Gross operating margin from our natural gas storage business was $10.7 million in the third quarter of 2008 compared to $7.6 million in the third quarter of 2007. The $3.1 million quarter-to-quarter increase in gross operating margin is primarily due to increased storage activity at our Petal natural gas storage facility. We placed an additional natural gas storage cavern having 4.2 Bcf of subscribed capacity in operation at the Petal facility during the third quarter of 2008. In addition, results from our Wilson natural gas storage facility in Texas improved quarter-to-quarter as we continue the progress of restoring commercial operations at this facility. Our Wilson facility has been under repairs during most of 2007 and 2008.

Offshore Pipelines & Services. Gross operating margin from this business segment was $17.5 million for the third quarter of 2008 compared to $46.7 million for the third quarter of 2007. The third quarter of 2007 includes $0.2 million of proceeds from business interruption insurance claims compared to none for the third quarter of 2008. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our offshore platform services business was $34.5 million for the third quarter of 2008 compared to $28.8 million for the third quarter of 2007. The $5.7 million quarter-to-quarter increase in gross operating margin from this business is largely due to contributions from our Independence Hub platform. Gross operating margin from our Independence Hub platform increased $11.1 million quarter-to-quarter due to an increase in processing revenues. Collectively, gross operating margin from our other platforms and related assets decreased $5.4 million quarter-to-quarter primarily due to lower demand fees and a decline in volumes on our Falcon platform as well as lower volumes at all of our

platforms due to hurricane-related disruptions in the third quarter of 2008. This includes $2.7 million of property damage repair expenses in the third quarter of 2008.

Gross operating margin from our offshore crude oil pipeline business was $5.7 million for the third quarter of 2008 compared to $8.9 million for the third quarter of 2007. Offshore crude oil transportation volumes decreased to 147 MBPD during the third quarter of 2008 from 163 MBPD during the third quarter of 2007. The $3.2 million quarter-to-quarter decrease in gross operating margin and 16 MBPD decrease in volumes from this business are primarily due to downtime and upstream volume disruptions as a result of Hurricanes Gustav and Ike in the third quarter of 2008. The quarter-to-quarter decrease in gross operating margin also reflects $0.7 million of hurricane-related property damage repair expenses in the third quarter of 2008.

Gross operating margin from our offshore natural gas pipeline business was a loss of $22.8 million for the third quarter of 2008 compared to $8.8 million of earnings for the third quarter of 2007. Our offshore natural gas transportation volumes were 1,244 BBtus/d during the third quarter of 2008 compared to 1,271 BBtus/d during the third quarter of 2007. The $31.6 million quarter-to-quarter decrease in gross operating margin from this business is primarily due to downtime, reduced volumes and property damage resulting from Hurricanes Gustav and Ike. Results for the third quarter of 2008 from this business include $32.1 million of hurricane-related property damage repair expenses. The effects of Hurricanes Gustav and Ike on this business were partially offset by a $10.1 million increase in gross operating margin from our Independence Trail Pipeline. The Independence Trail Pipeline benefited from a 499 BBtus/d quarter-to-quarter increase in transportation volumes.

Petrochemical Services. Gross operating margin from this business segment was $37.2 million for the third quarter of 2008 compared to $51.4 million for the third quarter of 2007. Gross operating margin from our propylene fractionation and pipeline business was $31.0 million for the third quarter of 2008 compared to $14.0 million for the third quarter of 2007. The $17.0 million quarter-to-quarter increase in gross operating margin is largely due to higher propylene sales margins during the third quarter of 2008 relative to the third quarter of 2007. Results for our propylene fractionation and related pipeline business for the third quarter of 2008 include $0.4 million of hurricane-related property damage repair expenses.

Gross operating margin from our octane enhancement business was a loss of $12.9 million for the third quarter of 2008 compared to $8.9 million of earnings for the third quarter of 2007. The $21.8 million quarter-to-quarter decrease in gross operating margin from this business is primarily due to downtime, reduced volumes and higher operating expenses as a result of operational issues during the third quarter of 2008 and the effects of Hurricane Ike. Gross operating margin from our butane isomerization business was $19.1 million for the third quarter of 2008 compared to $28.5 million for the third quarter of 2007. The $9.4 million quarter-to-quarter decrease in gross operating margin from this business is primarily due to reduced demand for isobutane from our octane enhancement facility due to operational issues in the third quarter of 2008 and downtime related to Hurricane Ike.

Comparison of Nine Months Ended September 30, 2008 with
Nine Months Ended September 30, 2007

Revenues for the first nine months of 2008 were $18.32 billion compared to $11.65 billion for the first nine months of 2007. The $6.67 billion period-to-period increase in consolidated revenues is primarily due to higher energy commodity sales volumes and prices during the first nine months of 2008 relative to the first nine months of 2007. These factors accounted for $5.88 billion of the period-to-period increase in consolidated revenues associated with our NGL, natural gas and petrochemical marketing activities. Consolidated revenues increased $684.7 million period-to-period due to the addition of revenues from newly constructed assets, principally our Meeker and Pioneer natural gas processing plants and our Independence Hub and Trail projects.

Operating costs and expenses were $17.24 billion for the first nine months of 2008 compared to $10.98 billion for the first nine months of 2007. The $6.26 billion period-to-period increase in consolidated operating costs and expenses is primarily due to higher costs of sales associated with our marketing activities. The cost of sales of our natural gas, NGL and petrochemical products increased $5.10 billion period-to-period primarily due to higher energy commodity sales volumes and prices. Operating costs and expenses associated with our natural gas processing plants increased $736.8 million period-to-period as a result of higher energy commodity prices and processing volumes during the first nine months of 2008 compared to the first nine months of 2007. Consolidated operating costs and expenses attributable to newly constructed assets increased $345.1 million period-to-period.

Changes in our revenues and 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 $1.62 per gallon for the nine months ended September 30, 2008 versus $1.09 per gallon during the nine months ended September 30, 2007. The Henry Hub market price for natural gas averaged $9.74 per MMBtu for the first nine months of 2008 versus $6.83 per MMBtu during the first nine months of 2007. For additional historical energy commodity pricing information, please see the table on page 55.

Equity earnings from our unconsolidated affiliates were $48.0 million for the first nine months of 2008 compared to $13.9 million for the first nine months of 2007, a period-to-period increase of $34.1 million. Equity earnings from our investment in Cameron Highway increased $26.3 million period-to-period due to higher transportation volumes and lower interest expense. On a 100% basis, Cameron Highway had crude oil transportation volumes of 171 MBPD during the first nine months of 2008 compared to 84 MBPD during the first nine months of 2007. Equity earnings from our investment in Jonah increased $11.7 million period-to-period. We earned a fixed 19.4% interest in Jonah during the third quarter of 2007 upon completion of certain achievements with respect to the Phase V Expansion of the Jonah Gathering System. Equity earnings from our investment in Nemo Gathering Company, LLC ("Nemo") increased $5.7 million period-to-period due to the recognition of a non-cash impairment charge in the second quarter of 2007. Collectively, equity earnings from our other investments decreased $9.6 million period-to-period due to higher repair and maintenance expenses during the first nine months of 2008 relative to the first nine months of 2007 as well as the effects of downtime and reduced volumes attributable to Hurricanes Gustav and Ike.

Operating income for the first nine months of 2008 was $1.06 billion compared to $613.3 million for the first nine months of 2007. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $446.8 million increase in operating income period-to-period.

Interest expense increased to $290.4 million for the first nine months of 2008 from $219.7 million for the first nine months of 2007. The $70.7 million period-to-period increase in interest expense is attributable to a higher average balance of debt principal outstanding. Our average debt principal outstanding was $7.65 billion for the first nine months of 2008 compared to $5.95 billion for the first nine months of 2007. We issued Senior Notes L in the third quarter of 2007, Senior Notes M and N in the second quarter of 2008 and Junior Subordinated Notes B in the third quarter of 2007.

Provision for income taxes increased $8.2 million period-to-period primarily due to the recognition of a $4.4 million benefit with respect to the Texas Margin Tax in the second quarter of 2007 and higher expenses associated with the Texas Margin Tax during the first nine months of 2008. The benefit was associated with a reorganization of certain of our entities from partnerships to limited liability companies effective September 30, 2007. Minority interest expense increased $10.1 million period-to-period attributable to the public unitholders of Duncan Energy Partners and third-party ownership interests in the Independence Hub platform.

As a result of the items noted in previous paragraphs, our consolidated net income increased $354.2 million to $726.0 million for the nine months ended September 30, 2008 compared to $371.8 million for the first nine months of 2007.

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

NGL Pipelines & Services. Gross operating margin from this business segment was $943.4 million for the first nine months of 2008 compared to $589.7 million for the first nine months of 2007, a period-to-period increase of $353.7 million. The first nine months of 2008 include $1.1 million of proceeds from business interruption insurance claims compared to $23.4 million of proceeds during the first nine months of 2007. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $611.8 million for the first nine months of 2008 compared to $283.5 million for the first nine months of 2007. The $328.3 million period-to-period increase in gross operating margin is largely due to higher natural gas processing margins and volumes and increased equity NGL production during the first nine months of 2008 relative to the first nine months of 2007. Total fee-based processing volumes increased to 2.5 Bcf/d during the first nine months of 2008 from 2.4 Bcf/d during the first nine months of 2007. Likewise, equity NGL production increased to 108 MBPD during the first nine months of 2008 from 67 MBPD during the first nine months of 2007.

Collectively, gross operating margin from our Meeker and Pioneer facilities increased $203.3 million period-to-period on a 47 MBPD increase in equity NGL production. Gross operating margin from our NGL marketing activities increased $70.3 million period-to-period primarily due to higher NGL sales margins and volumes. This business also benefited from improved natural gas processing margins in South Texas and the Permian Basin during the first nine months of 2008 relative to the first nine months of 2007. Gross operating margin from our South Texas processing plants and Chaco facility experienced a period-to-period increase of $41.3 million and $23.0 million, respectively. Collectively, gross operating margin from the remainder of our natural gas processing facilities decreased $9.7 million period-to-period primarily due to downtime, reduced volumes and property damage repair expenses affecting our Southern Louisiana natural gas processing plants as a result of Hurricanes Gustav and Ike.

Gross operating margin from our NGL pipelines and related storage business was $252.8 million for the first nine months of 2008 compared to $215.5 million for the first nine months of 2007. Total NGL transportation volumes increased to 1,788 MBPD during the first nine months of 2008 from 1,626 MBPD during the first nine months of 2007. The $37.3 million period-to-period increase in gross operating margin and 162 MBPD increase in transportation volumes from this business is primarily due to higher NGL transportation volumes and a system-wide tariff increase on our Mid-America Pipeline System.

Gross operating margin from our NGL fractionation business was $77.7 million for the first nine months of 2008 compared to $67.3 million for the first nine months of 2007. Fractionation volumes were 424 MBPD during the first nine months of 2008 compared to 379 MBPD during the first nine months of 2007. The $10.4 million period-to-period increase in gross operating margin and 45 MBPD increase in fractionation volumes is primarily due to contributions from our Hobbs fractionator. Gross operating margin from our Hobbs fractionator increased $23.1 million period-to-period on a 53 MBPD increase in NGL fractionation volumes. Collectively, gross operating margin from our other NGL fractionators decreased $12.7 million period-to-period primarily due to lower volumes at our Mont Belvieu and Norco fractionators. Our Mont Belvieu fractionator experienced downtime during the first quarter of 2008 for scheduled maintenance activities. Also, our Mont Belvieu and Norco fractionators experienced downtime and reduced volumes in the third quarter of 2008 due to the effects of Hurricanes Gustav and Ike.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $321.2 million for the first nine months of 2008 compared to $235.1 million for the first nine months of 2007. Our onshore natural gas transportation volumes were 7,309 BBtus/d during the first nine months of 2008 compared to 6,576 BBtus/d during the first nine months of 2007. Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business was $292.2 million for the first nine months of 2008 compared to $216.2 million for the first nine months of 2007. Collectively, gross operating margin from our natural gas pipelines increased $93.1 million period-to-period primarily due to (i) higher revenues from our San Juan Gathering System, (ii) higher transportation activity on our Texas Intrastate System, (iii) higher natural gas sales margins on our Acadian Gas System and (iv) increased equity earnings from our investment in Jonah.

Gross operating margin from our natural gas storage business was $29.0 million for the first nine months of 2008 compared to $18.9 million for the first nine months of 2007. The $10.1 million period-to-period increase in gross operating margin is primarily due to increased storage activity at our Petal natural gas storage facility and improved results at our Wilson facility. We placed additional natural gas storage caverns in operation during the third quarters of 2007 and 2008 at the Petal facility, which provided an additional 1.6 Bcf and 4.2 Bcf of subscribed capacity, respectively.

Gross operating margin from our natural gas marketing activities decreased $17.1 million period-to-period primarily due to non-cash mark-to-market related charges that are expected to be recouped in cash in future periods extending through 2009. Our natural gas marketing business has increased significantly during 2008. These marketing activities have four primary objectives: (i) to mitigate risk; (ii) maximize the use of our natural gas assets; (iii) to provide real-time market intelligence; and (iv) to link our noncontiguous natural gas assets together to enhance the profitability of such operations. To achieve these objectives, our natural gas marketing activities transact with various parties to provide transportation, balancing, storage, supply and sales services. The majority of our natural gas marketing activities are focused on the Gulf Coast and Rocky Mountain regions.

Our natural gas marketing business acquires a significant portion of the natural gas it sells from our processing plants and attracts additional supplies from third parties at pipeline interconnects to facilitate incremental throughput on our natural gas transportation pipelines. This purchased gas is then sold to industrial consumers, utilities and power plants at prices that include a transportation fee. In addition, sales are made with third party marketing companies at industry hub locations in order to balance our supply/demand portfolio. Our purchase and sale transactions are typically based on published daily or monthly index prices. We utilize financial instruments to hedge various transactions within our natural gas marketing business.

We use third party transportation and storage capacity to link together our non-contiguous natural gas assets. Our natural gas marketing business contracts with third party transportation and storage providers to provide services on both a firm and interruptible basis. This strategy allows us to compliment and strengthen our portfolio of natural gas assets.

Offshore Pipelines & Services. Gross operating margin from this business segment was $134.4 million for the first nine months of 2008 compared to $97.4 million for the first nine months of 2007. The $37.0 million period-to-period increase in segment gross operating margin is primarily due to contributions from our Independence Hub and Trail project and improved results from our Cameron Highway Oil Pipeline. Results from this business segment for the first nine months of 2008 were negatively impacted by (i) downtime and $17.0 million of repair expenses associated with a leak on the Independence Trail pipeline and (ii) the effects of Hurricanes Gustav and Ike including downtime, reduced volumes and $35.5 million of property damage repair expenses. The first nine months of 2008 include $0.2 million of proceeds from business interruption insurance claims compared to $1.5 million of proceeds during the first nine months of 2007. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance.

Gross operating margin from our offshore platform services business was $109.7 million for the first nine months of 2008 compared to $69.5 million for the first nine months of 2007. The $40.2 million period-to-period increase in gross operating margin is primarily due to our completion of the Independence Hub platform in March 2007. Gross operating margin increased period-to-period despite the platform being shut-in for 66 days during the second quarter of 2008 due to a leak on the Independence Trail export pipeline. While the Independence Hub platform did not earn volumetric fees during the period of suspended operations, the platform continued to earn its fixed demand revenues of approximately $5.0 million per month. Our net platform natural gas processing volumes increased to 588 MMcf/d during the first nine months of 2008 compared to 265 MMcf/d during the first nine months of 2007.

Gross operating margin from our offshore crude oil pipeline business was $32.7 million for the first nine months of 2008 versus $11.9 million for the first nine months of 2007. The $20.8 million period-to-period increase in gross operating margin is primarily due to increased equity earnings from Cameron Highway, which benefited from higher crude oil transportation volumes and lower interest expense in the first nine months of 2008 relative to the first nine months of 2007. Crude oil transportation volumes on the Cameron Highway Oil Pipeline System netted to our ownership interest were 85 MBPD in the first nine months of 2008 compared to 42 MBPD in the first nine months of 2007. Total offshore crude oil transportation volumes were 190 MBPD during the first nine months of 2008 versus 164 MBPD during the first nine months of 2007.

Gross operating margin from our offshore natural gas pipeline business was a loss of $8.3 million for the first nine months of 2008 compared to $14.6 million of earnings for the first nine months of 2007. Offshore natural gas transportation volumes were 1,449 BBtus/d during the first nine months of 2008 versus 1,407 BBtus/d during the first nine months of 2007. Gross operating margin from our Independence Trail pipeline, which first received production in July 2007, increased $24.1 million period-to-period on a 460 BBtus/d increase in transportation volumes. Collectively, gross operating margin from our other offshore natural gas pipelines decreased $47.0 million period-to-period primarily due to the effects of Hurricanes Gustav and Ike.

Petrochemical Services. Gross operating margin from this business segment was $136.5 million for the first nine months of 2008 compared to $139.3 million for the first nine months of 2007. Gross operating margin from our propylene fractionation business was $64.3 million for the first nine months of 2008 versus $45.6 million for the first nine months of 2007. The $18.7 million period-to-period increase in gross operating margin is largely due to higher propylene sales margins.

Gross operating margin from our butane isomerization business was $77.9 million for the first nine months of 2008 compared to $71.7 million for the first nine months of 2007. The $6.2 million period-to-period increase in gross operating margin is primarily due to strong demand for high-purity isobutane and higher NGL prices, which resulted in higher by-product sales revenues during the first nine months of 2008 relative to the first nine months of 2007. Butane isomerization volumes decreased to 85 MBPD during the first nine months of 2008 compared to 93 MBPD for the first nine months of 2007 due to production interruptions resulting from Hurricane Ike and operational issues at our octane enhancement facility during the third quarter of 2008.

Gross operating margin from our octane enhancement business was a loss of $5.7 million for the first nine months of 2008 compared to $22.1 million of earnings for the first nine months of 2007. The $27.8 million period-to-period decrease in gross operating margin is primarily due to downtime, reduced volumes and higher operating expenses as a result of operational issues during the third quarter of 2008 and the effects of Hurricane Ike.

Liquidity and Capital Resources

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business acquisitions and distributions to partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and short-term revolving credit arrangements. Capital expenditures for long-term needs resulting from business expansion projects and acquisitions are expected to be funded by a variety of sources (either separately or in combination) including net cash flows provided by operating activities, borrowings under credit facilities, the issuance of additional equity and debt securities and proceeds from divestitures of ownership interests in assets to affiliates or third parties. 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.

At September 30, 2008, we had $55.4 million of unrestricted cash on hand and approximately $539.3 million of available credit under EPO's Multi-Year Revolving Credit Facility. We had approximately $8.43 billion in principal outstanding under consolidated debt agreements at September 30,

2008. In total, our consolidated liquidity at September 30, 2008 was approximately $730.0 million, which includes the available borrowing capacity of our consolidated subsidiaries such as Duncan Energy Partners.

Recent volatility in global capital markets has resulted in a significant increase in the costs of incremental debt and equity capital and has reduced the availability of debt and equity capital. We expect that the current cost of capital may trend lower in the coming months as coordinated government-led funding programs are implemented worldwide. As the capital markets begin to stabilize and recover, we believe that we will have sufficient access to debt and equity capital to support our operating and investing activities. Costs of such capital, however, may remain significantly higher for an extended period of time. Our disciplined approach to funding capital spending and other partnership needs, combined with sufficient trade credit to operate our businesses efficiently, available borrowing capacity under our consolidated credit facilities and retained distributable cash flow, should provide us with a foundation to meet our anticipated liquidity and capital resource requirements.

For information regarding our risks in connection with the global financial crisis, see "The global financial crisis may have impacts on our business and financial condition that we currently cannot predict," under Item 1A of Part II of this quarterly report on Form 10-Q.

For additional information regarding our growth strategy, see "Capital Spending" included within this Item 2.

Registration Statements

We may issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. We have a universal shelf registration statement on file with the SEC registering the issuance of an unlimited amount of equity and debt securities. In April 2008, EPO issued $1.10 billion in principal amount of fixed-rate, unsecured senior notes under this registration statement. Net proceeds from these senior note offerings were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility.

We also have on file with the SEC a registration statement authorizing the issuance of up to 25,000,000 common units in connection with our distribution reinvestment program ("DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units of our partnership. An aggregate of 1,895,776 of our common units were issued in connection with the DRIP and a related plan during the nine months ended September 30, 2008. The issuance of these units generated $56.5 million in net proceeds that we used for general partnership purposes. In November 2008, affiliates of EPCO expect to reinvest $67.0 million in connection with the DRIP.

In March 2008, Duncan Energy Partners filed a universal shelf registration statement with the SEC that authorized its issuance of up to $1.00 billion in debt and equity securities. Duncan Energy Partners has not issued any securities under this registration statement through November 3, 2008.

Letter of Credit Facility

During the third quarter of 2008, a $60.0 million letter of credit was issued under EPO's Multi-Year Revolving Credit Facility to support our NYMEX margin requirements for natural gas financial instruments that are part of an economic hedge related to our natural gas processing business. In October 2008, EPO entered into a $100.0 million letter of credit facility. EPO issued a $70.0 million letter of credit under this new facility that replaced the letter of credit issued under its Multi-Year Revolving Credit Facility which was outstanding at September 30, 2008.

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Credit Ratings of EPO

At November 3, 2008, the investment grade credit ratings of EPO's senior unsecured debt securities were Baa3 by Moody's Investor Services and BBB- by Fitch Ratings and Standard and Poor's. Such ratings reflect only the view of the rating agency and should not be interpreted as a recommendation to buy, sell or hold our securities. These ratings may be revised or withdrawn at any time by the agencies at their discretion.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated (dollars in thousands). For information regarding the individual components of our cash flow amounts, see our Unaudited Condensed Statements of Consolidated Cash Flows included under Item 1 of this Quarterly Report.

	For the Nine Months Ended September 30,	
	2008	2007
Net cash flows provided by operating activities	$ 973,044	$ 937,835
Cash used in investing activities	1,709,203	2,039,495
Cash provided by financing activities	751,820	1,122,575

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

We use the indirect method to compute net cash flows provided by operating activities. See Note 17 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for information regarding this method of presentation.

Cash used in investing activities primarily represents expenditures for additions to property, plant and equipment, business combinations and investments in unconsolidated affiliates. Cash provided by financing activities generally consists of borrowings and repayments of debt, distributions to partners and proceeds from the issuance of equity securities. Amounts presented in our Unaudited Condensed Statements of Consolidated Cash Flows for borrowings and repayments under debt agreements are influenced by the magnitude of cash receipts and payments under our revolving credit facilities.

The following information highlights the significant period-to-period variances in our cash flow amounts:

Comparison of Nine Months Ended September 30, 2008 with
Nine Months Ended September 30, 2007

Operating Activities. Net cash flows provided by operating activities were $973.0 million for the nine months ended September 30, 2008 compared to $937.8 million for the nine months ended September 30, 2007. This $35.2 million increase in net cash flows provided by operating activities was primarily due to the following:

§ Net cash flows from consolidated operations (excluding cash payments for interest) increased $130.6 million period-to-period. This improvement in operating cash flow is generally due to an increase in gross operating margin between periods (see "Results of Operations" included within this Item 2) adjusted for the timing of related cash receipts and disbursements.

§ Cash payments for interest increased $112.9 million period-to-period primarily due to increased borrowings to finance our capital spending program and for general partnership purposes.

§ Increased distributions received from unconsolidated affiliates of $17.5 million for the nine months ended September 30, 2008 compared to the nine months ended September 30, 2007 due primarily to improved operations and earnings at Jonah Gas Gathering Company ("Jonah").

Investing Activities. Cash used in investing activities was $1.71 billion for the nine months ended September 30, 2008 compared to $2.04 billion for the nine months ended September 30, 2007. This $330.3 million decrease in cash used in investing activities was primarily due to the following:

§ Capital spending for property, plant and equipment, net of contributions in aid of construction, decreased $167.6 million period-to-period. For additional information related to our capital spending program, see "Capital Spending" included within this Item 2.

§ Cash outlays for investments in unconsolidated affiliates decreased by $257.1 million period-to-period. During the second quarter of 2007, we contributed $216.5 million to an unconsolidated affiliate, Cameron Highway. In return, Cameron Highway used these funds, along with an equal contribution from our 50% joint venture partner in Cameron Highway, to repay $430.0 million in outstanding debt. In addition, cash contributions to Jonah decreased $50.0 million period-to-period as a result of the timing of construction expenditures related to the Jonah Phase V expansion, which was completed in June 2008. Also, in the second quarter of 2008 we acquired a 50% interest in White River Hub, LLC ("White River Hub") and have contributed cash of $10.0 million since its acquisition.

§ A $32.7 million increase in restricted cash (a cash outflow) due to margin requirements related to financial instruments held in 2008 and proceeds held in connection with the Petal GO Zone bonds in 2007.

§ An increase of $56.3 million in cash used for business combinations primarily relating to the acquisition of the remaining interest in Dixie in August 2008.

Financing Activities. Cash provided by financing activities was $751.8 million for the nine months ended September 30, 2008 compared to $1.12 billion for the nine months ended September 30, 2007. This $370.8 million decrease in cash provided by financing activities was primarily due to the following:

§ Net borrowings under our consolidated debt agreements were $1.54 billion during the nine months ended September 30, 2008 compared to $1.47 billion during the nine months ended September 30, 2007. The $69.4 million increase was attributable to increased period-to-period borrowings to fund general partnership purposes.

§ Cash distributions to our partners and minority interests increased $77.8 million period-to-period primarily due to an increase in our common units outstanding and quarterly distribution rates, and an increase in the quarterly distribution rates of Duncan Energy Partners.

§ Contributions from minority interests decreased $302.9 million period-to-period due to the initial public offering of Duncan Energy Partners in February 2007, which generated proceeds of approximately $291.0 million.

§ The early termination and settlement of interest rate hedging financial instruments during the first nine months of 2008 resulted in net cash payments of $22.1 million compared to net cash receipts of $48.9 million during the same period in 2007, causing a $71.0 million decrease in financing cash flows between periods.

Capital Spending

An integral part of our business strategy involves expansion through business combinations, growth capital projects 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 such as the Piceance Basin of western Colorado, the Greater Green River Basin in Wyoming, the Barnett Shale in North Texas and the deepwater Gulf of Mexico.

Management continues to analyze potential acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In past years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We forecast that this trend will continue, and expect independent oil and natural gas companies to consider similar divestitures.

The following table summarizes our capital spending by activity on a cash basis for the periods indicated (dollars in thousands):

	For the Nine Months Ended September 30, 2008	2007
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	$ 1,464,439	$ 1,631,993
Capital spending for business combinations	57,090	785
Capital spending for acquisition of intangible assets (1)	5,126	--
Capital spending for investments in unconsolidated affiliates (2)	35,307	318,491
Total capital spending	$ 1,561,962	$ 1,951,269

(1) Represents the acquisition of permits for our Mont Belvieu storage facility.
(2) Capital spending for the nine months ended September 30, 2007 includes $216.5 million in cash contributions to Cameron Highway to fund our share of the repayment of its debt obligations.

Based on information currently available, we estimate our consolidated capital spending for property, plant and equipment for the remainder of 2008 (i.e., the fourth quarter) will approximate $555.2 million, which includes estimated expenditures of $494.6 million for growth capital projects and $60.6 million for sustaining capital expenditures.

Our forecast of consolidated capital expenditures is based on our current announced strategic operating and growth plans, which are dependent upon our ability to generate the required funds from either operating cash flows or from other means, including borrowings under debt agreements, issuance of equity and potential divestitures of certain assets to third and/or related parties. Our forecast of capital expenditures may change due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast may change as a result of decisions made by management at a later date, which may include acquisitions or decisions to take on additional partners.

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

At September 30, 2008, we had approximately $541.2 million in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction of our Barnett Shale natural gas pipeline project and Meeker natural gas processing plant expansion.

Spending Update Regarding Significant Ongoing Announced Growth Capital Projects

The following table summarizes information regarding selected significant announced growth capital projects (dollars in millions). Actual costs noted for each project reflects our share of cash expenditures as of September 30, 2008, excluding capitalized interest. The forecast amount noted for each project also reflects our share of project expenditures, excluding estimated capitalized interest.

Project Name	Estimated Date of Completion	Actual Costs	Current Forecast Total Cost
Mont Belvieu Storage Well Optimization Projects	Fourth Quarter 2008	$ 197.9	$ 235.4
Meeker II natural gas processing plant	Fourth Quarter 2008	372.2	451.8
ExxonMobil Conditioning & Treating Facility – Piceance Basin	Fourth Quarter 2008	164.5	184.6
Sherman Extension Pipeline (Barnett Shale)	2009	309.8	489.3
Shenzi Oil Pipeline	2009	121.4	160.1
Marathon Piceance Basin pipeline projects	2009	26.5	154.3
Trinity River Basin Extension	2009	--	232.6
Expansion of Wilson natural gas storage facility	2010	47.0	105.7
Texas Offshore Port System (TOPS and PACE)	2010	0.2	617.4

Pipeline Integrity Costs

Our NGL, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the U.S. Department of Transportation, through its Office of Pipeline Safety. The following table summarizes our pipeline integrity costs, net of indemnity payments received from El Paso, for the periods indicated (dollars in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Expensed	$ 14,556	$ 11,315	$ 38,396	$ 34,987
Capitalized	16,159	15,679	38,934	41,543
Total	$ 30,715	$ 26,994	$ 77,330	$ 76,530

We expect our cash outlay for the pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $34.7 million for the remainder of 2008. This amount includes $2.7 million attributable to pipeline integrity projects of Duncan Energy Partners.

Overview of Critical Accounting Policies and Estimates

A summary of the significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is included in our Annual Report on Form 10-K for the year ended December 31, 2007. Certain of these accounting policies require the use of estimates. As more fully described therein, the following estimates, in our opinion, are subjective in nature, require the exercise of 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 use of estimates for revenues and expenses; reserves for environmental matters; and natural gas imbalances. These estimates are based on our current knowledge and understanding and may change as a result of actions we may 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 financial position, results of operations and cash flows.

On a quarterly basis, we monitor the underlying business fundamentals of our investments in unconsolidated affiliates and test such investments for impairment when impairment indicators are present. As a result of our reviews for the third quarter of 2008, no impairment charges were required. We have the intent and ability to hold these investments, which are integral to our operations.

Other Items

Contractual Obligations

The following information summarizes significant changes in our contractual obligations since those presented in our Annual Report on Form 10-K at December 31, 2007 (dollars in thousands).

		Payment or Settlement due by Period			
Contractual Obligations	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Scheduled maturities of long-term debt (1)	$ 8,434,201	$ --	$ 1,726,000	$ 1,900,701	$ 4,807,500
Estimated cash payments for interest (2)	$ 9,212,927	$ 488,865	$ 867,389	$ 723,280	$ 7,133,393
Purchase obligations:					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas (3)	$ 5,707,213	$ 261,703	$ 985,430	$ 1,232,670	$ 3,227,410
Underlying volume commitment:					
Natural gas (in BBtus) (3)	927,765	45,360	158,775	199,505	524,125
Service payment commitments for pipeline capacity reservation (4)	$ 157,633	$ 2,730	$ 27,414	$ 30,074	$ 97,415

(1) Represents scheduled maturities of consolidated debt obligations at September 30, 2008. For additional information regarding or consolidated debt obligations, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.
(2) Our estimated cash payments for interest are based on the principle amount of consolidated debt obligations outstanding at September 30, 2008. With respect to variable-rate debt, we applied the weighted-average interest rates paid during the nine months ended September 30, 2008. With respect to fixed-rate debt, we applied the stated coupon rate of each debt instrument. Our estimate of cash payments for interest gives effect to interest rate swap agreements in place at September 30, 2008. In addition, our estimated cash payments are significantly influenced by the long-term maturities of our $550.0 million Junior Notes A (due August 2066) and $700.0 million Junior Notes B (due January 2068). Our estimated cash payments for interest assume that such subordinated debt obligations are not called prior to maturity.
(3) Reflects commitments associated with new natural gas purchase agreements executed during the second and third quarters of 2008 in connection with our natural gas marketing activities.
(4) Reflects commitments associated with a pipeline capacity reservation agreement executed during the third quarter of 2008 in connection with our natural gas marketing activities.

Off-Balance Sheet Arrangements

There have been no significant changes with regards to our off-balance sheet arrangements since those reported in our Annual Report on Form 10-K for the year ended December 31, 2007.

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Summary of Related Party Transactions

The following table summarizes our revenue and expense transactions with related parties for the periods indicated (dollars in thousands).

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Revenues from consolidated operations:				
EPCO and affiliates	$ 47,215	$ 12,673	$ 91,922	$ 42,778
Energy Transfer Equity and subsidiaries	99,583	78,957	412,975	121,521
Unconsolidated affiliates	153,361	87,209	318,710	215,015
Total	$ 300,159	$ 178,839	$ 823,607	$ 379,314
Operating costs and expenses:				
EPCO and affiliates	$ 87,991	$ 72,296	$ 274,406	$ 219,879
Energy Transfer Equity and subsidiaries	56,528	2,614	134,447	8,385
Unconsolidated affiliates	20,688	6,414	68,214	22,628
Total	$ 165,207	$ 81,324	$ 477,067	$ 250,892
General and administrative costs:				
EPCO and affiliates	$ 13,403	$ 11,504	$ 44,631	$ 45,292
Unconsolidated affiliates	(37)	--	(37)	--
Total	$ 13,366	$ 11,504	$ 44,594	$ 45,292
Other expense:				
EPCO and affiliates	$ --	$ --	$ (274)	$ 170

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.

We have an extensive and ongoing relationship with EPCO and its affiliates, including TEPPCO. Our revenues from EPCO and affiliates are primarily associated with sales of NGL products. Our expenses with EPCO and affiliates are primarily due to (i) reimbursements we pay EPCO in connection with an administrative services agreement (the "ASA") and (ii) purchases of NGL products.

TEPPCO became a related party to us in February 2005 when its general partner was acquired by private company affiliates of EPCO. Our relationship with TEPPCO was further strengthened by the acquisition of TEPPCO's general partner by Enterprise GP Holdings in May 2007. Enterprise GP Holdings also owns our general partner. TEPPCO is also a joint venture partner with us in Jonah Gas Gathering Company and the Texas Offshore Port System.

On February 5, 2007, our consolidated subsidiary, Duncan Energy Partners, completed an initial public offering of its units, which generated net proceeds of approximately $291.0 million. Duncan Energy Partners was formed in September 2006 to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO.

Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity and its general partner in May 2007. As a result, Energy Transfer Equity and its consolidated subsidiaries became related parties to our consolidated businesses.

Many of our unconsolidated affiliates perform supporting or complementary roles to our consolidated business operations. The majority of our revenues from unconsolidated affiliates are earned from our sale of natural gas to Evangeline. The majority of our expenses with unconsolidated affiliates pertain to (i) our purchase of natural gas from Jonah and (ii) NGL transportation, storage and fractionation services we receive from K/D/S Promix, L.L.C.

Non-GAAP reconciliations

A reconciliation of our measurement of total non-GAAP gross operating margin to GAAP operating income and income before provision for income taxes and minority interest follows (dollars in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Total segment gross operating margin	$ 478,922	$ 363,721	$ 1,535,500	$ 1,061,568
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(138,417)	(133,869)	(408,601)	(374,522)
Operating lease expense paid by EPCO	(526)	(526)	(1,579)	(1,579)
Loss (gain) from asset sales and related transactions in operating costs and expenses	857	219	1,699	(5,445)
General and administrative costs	(21,720)	(18,715)	(66,901)	(66,706)
Operating income	319,116	210,830	1,060,118	613,316
Other expense, net	(101,479)	(83,369)	(287,672)	(213,327)
Income before provision for income taxes and minority interest	$ 217,637	$ 127,461	$ 772,446	$ 399,989

EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railcars for $1 per year (the “retained leases”). These subleases are part of the ASA that we executed with EPCO in connection with our formation in 1998. EPCO holds this equipment pursuant to operating leases for which it has retained the corresponding cash lease payment obligation. We record the full value of such lease payments made by EPCO as a non-cash related party operating expense, with the offset to partners’ equity recorded as a general contribution to our partnership. Apart from the partnership interests we granted to EPCO at our formation, EPCO does not receive any additional ownership rights as a result of its contribution to us of the retained leases.

For the three and nine months ended September 30, 2008, we recorded $0.5 million and $1.6 million, respectively, of retained lease expense. We have exercised our election under the retained leases to purchase a cogeneration unit in December 2008 for $2.3 million. Should we decide to exercise the purchase option associated with the remaining agreement, we would pay the original lessor $3.1 million in June 2016.

Recent Accounting Pronouncements

On January 1, 2008, we adopted the provisions of Statement of Financial Accounting Standards (“SFAS”) 157, Fair Value Measurements, which apply to financial assets and liabilities. SFAS 157 defines fair value 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. See Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for information regarding fair value disclosures pertaining to our financial assets and liabilities.

For information regarding accounting developments during the first nine months of 2008 that will affect our future financial statements, see Note 2 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.

Weather-related Risks

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which are customary and sufficient for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance will not cover every type of interruption that might occur. If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient to reimburse us for our repair costs or lost income. Any event that interrupts the revenues generated by our consolidated operations, or which causes us to make significant 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 windstorm events such as hurricanes and tropical storms, EPCO's deductible for onshore physical damage is $10.0 million per storm. For offshore assets, the windstorm deductible is $10.0 million per storm plus a one-time $15.0 million aggregate deductible per policy period. For non-windstorm events, EPCO's deductible for onshore and offshore physical damage is $5.0 million per occurrence. In meeting the deductible amounts, property damage costs are aggregated for EPCO and its affiliates, including us. Accordingly, our exposure with respect to the deductibles may be equal to or less than the stated amounts depending on whether other EPCO or affiliate assets are also affected by an event.

To qualify for business interruption coverage in connection with a windstorm event, covered assets must be out-of-service in excess of 60 days for onshore assets and 75 days for offshore assets. To qualify for business interruption coverage in connection with a non-windstorm event, covered onshore and offshore assets must be out-of-service in excess of 60 days.

Hurricanes Gustav and Ike

In the third quarter of 2008, our onshore and offshore facilities located along the Gulf Coast of Texas and Louisiana were adversely impacted by Hurricanes Gustav and Ike. The disruptions in natural gas, NGL and crude oil production caused by these storms resulted in decreased volumes for some of our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which, in turn, caused a decrease in gross operating margin from these operations. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, we expensed a combined $46.0 million of repair costs for property damage in connection with these two storms. We expect to file property damage insurance claims to the extent repair costs exceed this amount. Due to the recent nature of these storms, we are still evaluating the total cost of repairs and the potential for business interruption claims on certain assets.

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 in connection with Hurricanes Katrina and Rita.

Item 3. Quantitative and Qualitative Disclosures about Market Risk.

We are exposed to financial market risks, including changes in commodity prices, interest rates and foreign exchange rates. We may use financial instruments (e.g., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the types of risks we attempt to hedge are those related to (i) the variability of future earnings, (ii) fair values of certain debt instruments and (iii) cash flows resulting from changes in applicable interest rates, commodity prices or exchange rates.

We recognize financial instruments as assets and liabilities on our Unaudited Condensed Consolidated Balance Sheets based on fair value. Fair value is generally defined as the amount at which a financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation techniques. We must use considerable judgment, however, in interpreting market data and developing these estimates. Accordingly, our fair value estimates are not necessarily indicative of the amounts that we could realize upon disposition of these instruments.

The use of different market assumptions and/or estimation techniques could have a material effect on our estimates of fair value.

Changes in fair value of financial instrument contracts are recognized in earnings in the current period unless specific hedge accounting criteria are met. If the financial instrument meets the criteria of a fair value hedge, gains and losses incurred on the instrument will be recorded in earnings to offset corresponding losses and gains on the hedged item. If the financial instrument meets the criteria of a cash flow hedge, gains and losses incurred on the instrument are recorded in accumulated other comprehensive income. Gains and losses on cash flow hedges are reclassified from accumulated other comprehensive income to earnings when the forecasted transaction occurs or, as appropriate, over the economic life of the hedged item. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

To qualify for hedge accounting, the item to be hedged must expose us to risk and the related hedging instrument must reduce the exposure and meet the formal hedging requirements of SFAS 133, Accounting for Derivative Instruments and Hedging Activities (as amended and interpreted). We formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at its inception and thereafter on a quarterly basis. Any hedge ineffectiveness is immediately recognized in earnings.

We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific hedging criteria. When this occurs, we may enter into a new financial instrument to reestablish the hedge to which the closed instrument relates.

Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed interest rate borrowings under various debt agreements. We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt.

Fair Value Hedges – Interest Rate Swaps

As summarized in the following table, we had five interest rate swap agreements outstanding at September 30, 2008 that were accounted for as fair value hedges.

Hedged Fixed Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Value
Senior Notes C, 6.375% fixed rate, due Feb. 2013	1	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 5.02%	$100.0 million
Senior Notes G, 5.60% fixed rate, due Oct. 2014	4	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 3.63%	$400.0 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

The aggregate fair value of the five interest rate swaps at September 30, 2008 was an asset of $13.2 million, with an offsetting increase in the fair value of the underlying debt. There were eleven interest rate swaps outstanding at December 31, 2007 having an aggregate fair value of $14.8 million (an asset). Interest expense for the three months ended September 30, 2008 and 2007 includes a $1.8 million benefit and a $2.3 million loss, respectively, from interest rate swap agreements. For the nine months ended September 30, 2008 and 2007, interest expense reflects a benefit of $3.2 million and a loss of $6.9 million, respectively, from interest rate swap agreements.

The following table summarizes the termination of our interest rate swaps during 2008 (dollars in millions):

	Notional Value	Cash Gains (1)
Interest rate swap portfolio, December 31, 2007	$ 1,050.0	$ --
First quarter of 2008 terminations	(200.0)	6.3
Second quarter of 2008 terminations	(250.0)	12.0
Third quarter of 2008 terminations (2)	(100.0)	--
Interest rate swap portfolio, September 30, 2008	$ 500.0	$ 18.3

(1) Cash gains resulting from the termination, or monetization, of interest rate swaps will be amortized to earnings as a reduction to interest expense over the remaining life of the underlying debt.
(2) In early October 2008, one counterparty filed for bankruptcy. At September 30, 2008, the fair value of this interest rate swap was $3.4 million and this amount has been fully reserved. Hedge accounting for this swap has been discontinued.

The following table shows the effect of hypothetical price movements on the estimated fair value of our interest rate swap portfolio and the related change in fair value ("FV") of the underlying debt at the dates indicated (dollars in millions). Income is not affected by changes in the fair value of these swaps; however, these swaps effectively convert the hedged portion of fixed-rate debt to variable-rate debt. As a result, interest expense (and related cash outlays for debt service) will increase or decrease with the change in the periodic "reset" rate associated with the respective swap. Typically, the reset rate is an agreed upon index rate published for the first day of the six-month interest calculation period.

		Portfolio Fair Value at	
Scenario	Resulting Classification	September 30, 2008	October 21, 2008
FV assuming no change in underlying interest rates	Asset	$ 13.2	$ 20.1
FV assuming 10% increase in underlying interest rates	Asset	3.0	11.2
FV assuming 10% decrease in underlying interest rates	Asset	23.3	28.9

Cash Flow Hedges – Interest Rate Swaps

Duncan Energy Partners had three floating-to-fixed interest rate swap agreements outstanding at September, 2008 that were accounted for as cash flow hedges.

Hedged Variable Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Variable to Fixed Rate (1)	Notional Value
Duncan Energy Partners' Revolver, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	3.77% to 4.62%	$175.0 million

(1) Amounts receivable from or payable to the swap counterparties are settled every three months (the "settlement period").

We recognized losses of $0.8 million and $1.6 million from these swap agreements during the three and nine months ended September 30, 2008, respectively. The aggregate fair values of these interest rate swaps at September 30, 2008 and December 31, 2007 were liabilities of $4.3 million and $3.8 million, respectively. As cash flow hedges, any increase or decrease in fair value of the financial instrument (to the extent effective) would be recorded as other comprehensive income and amortized into earnings based on the settlement period being hedged. Over the next twelve months, we expect to reclassify $1.4 million of losses to earnings as an increase in interest expense.

The following table shows the effect of hypothetical price movements on the estimated fair value of Duncan Energy Partners' interest rate swap portfolio (dollars in millions).

		Portfolio Fair Value at	
Scenario	Resulting Classification	September 30, 2008	October 21, 2008
FV assuming no change in underlying interest rates	Liability	$ (4.3)	$ (6.3)
FV assuming 10% increase in underlying interest rates	Liability	(3.3)	(5.5)
FV assuming 10% decrease in underlying interest rates	Liability	(5.3)	(7.1)

Cash Flow Hedges – Treasury Locks

We occasionally use treasury lock financial instruments to hedge the underlying U.S. treasury rates related to our anticipated issuances of debt. Cash gains or losses on the termination, or monetization, of such instruments are amortized to earnings using the effective interest method over the estimated term of the underlying fixed-rate debt. Each of our treasury lock transactions were designated as a cash flow hedge. The following table summarizes changes in our treasury lock portfolio since December 31, 2007 (dollars in millions).

	Notional Value	Cash Losses (1)
Treasury lock portfolio, December 31, 2007	$ 600.0	$ --
First quarter of 2008 terminations	(350.0)	27.7
Second quarter of 2008 terminations	(250.0)	12.7
Treasury lock portfolio, September 30, 2008	$ --	$ 40.4

(1) Cash losses are included in net interest rate financial instrument losses in the Unaudited Condensed Statements of Consolidated Comprehensive Income.

We expect to reclassify $1.8 million of cumulative net gains from the monetization of treasury lock financial instruments to earnings (as a decrease in interest expense) over the next twelve months. This includes financial instruments that were settled in years prior to 2008.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and certain petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risks associated with such products, we may enter into commodity financial instruments.

The primary purpose of our commodity risk management activities is to reduce our exposure to price risks associated with (i) natural gas purchases, (ii) the value of NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas, NGLs or certain petrochemical products. From time to time, we inject natural gas into storage and may utilize hedging instruments to lock in the value of our inventory positions. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

We assess the risk of our commodity financial instrument portfolio using a sensitivity analysis model. The sensitivity analysis applied to the portfolio measures the potential income or loss (i.e., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at the date indicated within the following table.

We have segregated our commodity financial instruments portfolio between those financial instruments utilized in connection with our natural gas marketing activities and those used in connection with our NGL and petrochemical operations.

Natural gas marketing activities. At September 30, 2008 and December 31, 2007, the aggregate fair values of those financial instruments utilized in connection with our natural gas marketing activities was an asset of $0.8 million and a liability of $0.3 million, respectively. Our natural gas marketing business and its related use of financial instruments has increased since December 31, 2007. We currently utilize mark-to-market accounting for substantially all of the financial instruments utilized in connection with our natural gas marketing activities. The following table presents gains and losses recognized in earnings from this portion of the commodity financial instruments portfolio for the periods indicated (dollars in millions):

Three months ended September 30, 2008	Gains	$	13.2
Three months ended September 30, 2007	Losses	$	(0.6)
Nine months ended September 30, 2008	Gains	$	7.8
Nine months ended September 30, 2007	Losses	$	(0.1)

The following table shows the effect of hypothetical price movements on the estimated fair value of this component of the overall portfolio at the dates presented (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at September 30, 2008	Portfolio Fair Value at October 21, 2008
FV assuming no change in underlying commodity prices	Asset (Liability)	$ 0.8	$ (0.5)
FV assuming 10% increase in underlying commodity prices	(Liability)	(3.8)	(7.8)
FV assuming 10% decrease in underlying commodity prices	Asset	6.0	6.9

The change in fair value of the instruments between September 30, 2008 and October 21, 2008 is primarily due to a decrease in natural gas prices.

NGL and petrochemical operations. At September 30, 2008 and December 31, 2007, the aggregate fair values of financial instruments utilized in connection with our NGL and petrochemical operations were liabilities of $116.6 million and $19.0 million, respectively. The change in fair value between December 31, 2007 and September 30, 2008 is primarily due to a decrease in the price of natural gas and an increase in volumes hedged. Almost all of the financial instruments within this portion of the commodity financial instruments portfolio are accounted for as cash flow hedges, with a small number accounted for using mark-to-market accounting.

EPO has employed a program to economically hedge a portion of earnings from its natural gas processing business (a component of its NGL Pipelines & Services business segment). This program consists of (i) the forward sale of a portion of EPO's expected equity NGL production volumes at fixed prices through 2009 and (ii) the purchase (using commodity financial instruments) of the amount of natural gas expected to be consumed as plant thermal reduction ("PTR") in the production of such equity NGL volumes. The objective of this strategy is to hedge a level of gross margins (i.e., NGL sales revenues less actual costs for PTR and the gain or loss on the PTR hedge) associated with the forward sales contracts by fixing the cost of natural gas used for PTR, through the use of commodity financial instruments. At September 30, 2008, this hedging program had hedged future gross margins before plant operating expenses of $588.8 million for 28.8 million barrels of forecasted NGL forward sales transactions extending through 2009.

NGL forward sales contracts are not accounted for as financial instruments under SFAS 133; therefore, changes in the aggregate economic value of these sales contracts are not reflected in earnings and comprehensive income until the volumes are delivered to customers. On the other hand, the commodity financial instruments used to purchase the related quantities of PTR (i.e., "PTR hedges") are accounted for as cash flow hedges; therefore, changes in the aggregate fair value of the PTR hedges are presented in other comprehensive income.

Prior to actual settlement, if the market price of natural gas is less than the price stipulated in a PTR hedge, we recognize an unrealized loss in other comprehensive income for the excess of the natural gas price stated in the PTR hedge over the market price. To the extent that we realize such financial losses upon settlement of the instrument, the losses are added to the actual cost we have to pay for PTR (which would then be based on the lower market price). The end result of this relationship – financial gain/loss on the PTR hedges plus the market price of actual natural gas purchases at the time of consumption – is that our total cost of natural gas used for PTR approximates the amount we originally hedged under this program The converse is true if the price of natural gas decreases. During the third quarter of 2008, the price of natural gas decreased approximately 45% from June 30, 2008. As a result, we recognized unrealized losses in other comprehensive income with respect to the PTR hedges of $258.4 million during the third quarter of 2008. For the nine months ended September 30, 2008, we recognized unrealized losses in other comprehensive income of $126.0 million with respect to the PTR hedging program. Once the forecasted NGL forward sales transactions occur, any realized gains and losses on the cash flow hedges would be reclassified into earnings at that time.

At November 1, 2008, this program had hedged future gross margins before plant operating expenses of $550.0 million for 27.3 million barrels of forecasted NGL forward sales transactions extending through 2009. The aggregate fair value of the PTR cash flow hedges at this date was a liability of $155.3 million.

The following table presents gains and losses recognized in earnings from this portion of the commodity financial instruments portfolio for the periods indicated (dollars in millions):

Three months ended September 30, 2008 (1)	Losses	$	(7.2)
Three months ended September 30, 2007	Losses	$	(10.1)
Nine months ended September 30, 2008 (2)	Gains	$	1.7
Nine months ended September 30, 2007	Losses	$	(11.9)

(1) Includes ineffectiveness of $5.6 million (an expense).
(2) Includes ineffectiveness of $2.8 million (an expense).

The following table shows the effect of hypothetical price movements on the estimated fair value of this component of the overall portfolio at the dates presented (dollars in millions):

		Portfolio Fair Value at	
Scenario	Resulting Classification	September 30, 2008	October 21, 2008
FV assuming no change in underlying commodity prices	(Liability)	$ (116.6)	$ (107.4)
FV assuming 10% increase in underlying commodity prices	(Liability)	(97.3)	(86.0)
FV assuming 10% decrease in underlying commodity prices	(Liability)	(136.0)	(128.8)

The change in fair value of the NGL and petrochemical portfolio between September 30, 2008 and October 21, 2008 is primarily due to a decrease in natural gas prices. A significant number of the financial instruments in this portfolio hedge the purchase of physical natural gas. If natural gas prices fall below the price stipulated in such financial instruments, we recognize a liability for the difference; however, if prices partially or fully recover, this liability would be reduced or eliminated, as appropriate.

Foreign Currency Hedging Program

We are exposed to foreign currency exchange rate risk primarily through our Canadian NGL marketing subsidiary. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Canadian dollar. We attempt to hedge this risk using foreign exchange purchase contracts to fix the exchange rate. Mark-to-market accounting is utilized for these contracts, which typically have a duration of one month. For the nine months ended September 30, 2008, we recorded minimal gains from these financial instruments. No such amounts were recorded in the third quarter of 2008.

Fair Value Information

On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. SFAS 157 defines fair value 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. See Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for information regarding fair value disclosures pertaining to our financial assets and liabilities.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) primarily includes the effective portion of the gain or loss on financial instruments designated and qualified as a cash flow hedge, foreign currency adjustments and Dixie's minimum pension liability adjustments. Amounts accumulated in other comprehensive income (loss) from cash flow hedges are reclassified into earnings in the same period(s) in which the hedged forecasted transactions (such as a forecasted forward sale of NGLs) affect earnings. If it becomes probable that the forecasted transaction will not occur, the net gain or loss in accumulated other comprehensive income (loss) must be immediately reclassified.

The following table presents the components of accumulated other comprehensive income (loss) at the dates indicated:

	September 30, 2008	December 31, 2007
Commodity financial instruments – cash flow hedges (1)	$ (129,913)	$ (21,619)
Interest rate financial instruments – cash flow hedges	9,714	34,980
Foreign currency cash flow hedges	--	1,308
Foreign currency translation adjustment (2)	1,652	1,200
Pension and postretirement benefit plans (3)	324	588
Total accumulated other comprehensive income (loss)	$ (118,223)	$ 16,457

(1) The negative change in fair value of commodity financial instruments between December 31, 2007 and September 30, 2008 is primarily due to a significant decrease in natural gas prices during the third quarter of 2008.
(2) Relates to transactions of our Canadian NGL marketing subsidiary.
(3) See Note 2 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for additional information regarding Dixie's pension and postretirement benefit plans.

Item 4. Controls and Procedures.

Our management, with the participation of the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") of Enterprise Products GP, has evaluated the effectiveness of our disclosure controls and procedures, as of September 30, 2008. Based on their evaluation, the CEO and CFO of Enterprise Products GP have concluded that our disclosure controls and procedures (as defined in Rule 13a-15(e)) are effective at a reasonable assurance level.

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

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us in reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time specified in the Commission's rules and forms, including to provide reasonable assurance that such information is accumulated and communicated to our management, including the CEO and CFO of our general partner, as appropriate, to allow timely decisions regarding required disclosures. Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Partnership have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls is also based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

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 on Form 10-Q.

PART II. OTHER INFORMATION.

Item 1. Legal Proceedings.

See Part I, Item 1, Financial Statements, Note 15, "Commitments and Contingencies – Litigation," of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report, which is incorporated herein by reference.

Item 1A. Risk Factors.

Apart from that discussed below, there have been no significant changes in our risk factors since December 31, 2007. For a detailed discussion of our risk factors, please read Part I, Item 1A "Risk Factors," in our Annual Report on Form 10-K for the year ended December 31, 2007.

Our recently announced TOPS joint venture, like other projects for new facilities, is subject to various business, operational and regulatory risks and may not be successful.

The TOPS joint venture is expected to represent an important component of our Offshore Pipelines & Services segment, requiring an estimated $617.4 million in capital contributions from us through 2011 (excluding capitalized interest). We, as well as each of our other two joint venture partners, will own a one-third interest in TOPS, and we will act as operator and construction manager for TOPS. We may be unable to make required capital contributions due to an inability to access capital markets or otherwise, in which event our interest could be diluted, and we could suffer other adverse consequences. Please read the risk factor in Item 1A of our most recent Form 10-K "We may not be able to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for investment opportunities."

Delays in completing construction or commencement of operations of TOPS due to any cause would delay our future operating cash flows, which could have a material adverse effect on the success of the TOPS project and on our business, results of operations, financial condition and prospects. As with our other construction projects for new facilities, it may take a period of time before we realize any expected cash flows from such assets. Please read the risk factor in Item 1A of our most recent Form 10-K "Our operating cash flows from our capital projects may not be immediate."

Commencement of the TOPS joint venture operations, like other new facilities, is also subject to obtaining necessary regulatory and third-party approvals. The offshore terminal will require approval by the U.S. Coast Guard and issuance of a Deepwater Port License, while the onshore pipeline and storage facilities will be subject to review by the U.S. Environmental Protection Agency, Army Corps of Engineers and Department of Transportation. Obtaining such approvals is a time consuming process. For example, we estimate that the Deepwater Port License could take as long as two years, assuming there are no delaying factors. These and other regulatory, environmental, political and legal risks are beyond our control and may also require the expenditure of unexpected amounts of capital. Please read the risk factor in Item 1A of our most recent Form 10-K "Our construction of new assets is subject to regulatory, environmental, political, legal and economic risks, which may result in delays, increased costs or decreased cash flows."

The TOPS joint venture is also subject to significant logistical, technological and staffing requirements, as well as force majeure events such as hurricanes along the Gulf Coast, that could result in delays or significant increases in the project's current estimated costs. Please read the risk factor in Item 1A of our most recent Form 10-K "Our actual construction, development and acquisition costs could exceed forecasted amounts."

The global financial crisis may have impacts on our business and financial condition that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system has had, and may continue to have, an impact on our business and our financial condition. We may face significant challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be severely restricted at a time when we would like, or need, to do so, which could have an adverse impact on our ability to meet our capital commitments and flexibility to react to changing economic and business conditions. The credit crisis could have a negative impact on our lenders or our customers, causing them to fail to meet their obligations to us. Additionally, demand for our services and products depends on activity and expenditure levels in the energy industry, which are directly and negatively impacted by depressed oil and gas prices. Any of these factors could lead to reduced usage of our pipelines and energy logistics services, which could have a material negative impact on our revenues and prospects.

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

As of September 30, 2008, we and our affiliates are authorized to repurchase up to 618,400 common units under the December 1998 common unit repurchase program. We did not repurchase any of our common units in connection with this announced program during the three or nine months ended September 30, 2008.

The following table summarizes our repurchase activity during 2008 in connection with other arrangements:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of of Units Purchased as Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
May 2008	21,413 (1)	$30.37	-0-	-0-
August 2008	4,940 (2)	$29.19	-0-	-0-
September 2008	4,565 (3)	$25.77	-0-	-0-

(1) Of the 67,500 restricted unit awards that vested in May 2008 and converted to common units, 21,413 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
(2) Of the 28,650 restricted unit awards that vested in August 2008 and converted to common units, 4,940 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
(3) Of the 16,500 restricted unit awards that vested in September 2008 and converted to common units, 4,565 of these units were sold back to the partnership by employees to cover related withholding tax requirements.

Item 3. Defaults upon Senior Securities.

None.

Item 4. Submission of Matters to a Vote of Security Holders.

On January 29, 2008, we held a special meeting where our unitholders where asked to approve the terms of the Enterprise Products 2008 Long-Term Incentive Plan (the "2008 LTIP"). See Item 4 of our Annual Report on Form 10-K for information regarding this matter and related vote totals.

Item 5. Other Information.

Amendments to Partnership Agreement

On November 6, 2008, our general partner amended our agreement of limited partnership to amend Section 7.7(i) to clarify and to provide that any amendment of Section 7.7 shall not impair an indemnitee's right to receive expense advancement, in addition to indemnification, from us as otherwise provided for under the partnership agreement. In addition, the member of our general partner amended its limited liability company agreement to make a similar change.

A copy of the amendments to our partnership agreement and our general partner's limited liability company agreement are attached hereto as Exhibit 3.5 and Exhibit 3.7, respectively, and are incorporated by reference herein.

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 the 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).
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 8, 2007).
3.2	

	Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 8, 2005 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 10, 2005).
3.3	First Amendment to Fifth Amended and Restated Partnership Agreement of Enterprise Products Partners L.P. dated as of December 27, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K/A filed January 3, 2008).
3.4	Second Amendment to Fifth Amended and Restated Partnership Agreement of Enterprise Products Partners L.P. dated as of April 14, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 16, 2008).
3.5#	Third Amendment to Fifth Amended and Restated Partnership Agreement of Enterprise Products Partners L.P. dated as of November 6, 2008.

3.6	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated as of November 7, 2007 (incorporated by reference to Exhibit 3.2 to Form 10-Q filed November 8, 2007).
3.7#	First Amendment to Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated as of November 6, 2008.
3.8	Limited Liability Company Agreement of Enterprise Products Operating LLC dated as of June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed on 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).
3.11	Certificate of Limited Partnership of Duncan Energy Partners L.P. (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P. Form S-1 Registration Statement, Reg. No. 333-138371, filed November 2, 2006).
3.12	Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P., dated February 5, 2007 (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P.'s Form 8-K/A filed February 5, 2007).
3.13	First Amendment to Amended and Restated Partnership Agreement of Duncan Energy Partners L.P. dated as of December 27, 2007 (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P.'s Form 8-K/A filed on January 3, 2008).
4.1	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-1/A; File 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 LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed on August 8, 2007) .
4.6	Amended and Restated Revolving Credit Agreement dated as of November 19, 2007 among Enterprise Products Operating LLC, the financial institutions party thereto as lenders, Wachovia Bank, National Association, as

	Administrative Agent, Issuing Bank and Swingline Lender, Citibank, N.A. and JPMorgan Chase Bank, as Co-Syndication Agents, and SunTrust Bank, Mizuho Corporate Bank, Ltd. and The Bank of Nova Scotia, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Form 8-K filed on November 20, 2007).
4.7	Amended and Restated Guaranty Agreement dated as of November 19, 2007 executed by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed on November 20, 2007).
4.8	Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed on October 6, 2004).

4.9	First Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on October 6, 2004).
4.10	Second Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on October 6, 2004).
4.11	Third Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed on October 6, 2004).
4.12	Fourth Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed on October 6, 2004).
4.13	Fifth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on March 3, 2005).
4.14	Sixth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on March 3, 2005).
4.15	Seventh Supplemental Indenture dated as of June 1, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.46 to Form 10-Q filed November 4, 2005).
4.16	Eighth Supplemental Indenture dated as of July 18, 2006 to Indenture dated 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 4.2 to Form 8-K filed July 19, 2006).
4.17	Ninth Supplemental Indenture, dated as of May 24, 2007, by and 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 the Current Report on Form 8-K filed by Enterprise Products Partners L.P. on May 24, 2007).
4.18	Tenth Supplemental Indenture, dated as of June 30, 2007, by and 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 4.54 to Form 10-Q filed August 8, 2007).

4.19	Eleventh Supplemental Indenture, dated as of September 4, 2007, by and 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 on September 5, 2007).
4.20	Twelfth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.21	Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.22	Global Note representing $350 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).

4.23	Global Note representing $500 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 10-K filed March 31, 2003).
4.24	Global Notes representing $450 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).
4.25	Global Note representing $500 million principal amount of 4.000% Series B Senior Notes due 2007 with attached Guarantee (incorporated by reference to Exhibit 4.14 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.26	Global Note representing $500 million principal amount of 5.600% 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 on March 4, 2005).
4.27	Global Note representing $150 million principal amount of 5.600% 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 on March 4, 2005).
4.28	Global Note representing $350 million principal amount of 6.650% 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 on March 4, 2005).
4.29	Global Note representing $500 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.27 to Form 10-K for the year ended December 31, 2004 filed on March 15, 2005).
4.30	Global Note representing $250,000,000 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 on November 4, 2005).
4.31	Global Note representing $250,000,000 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 on November 4, 2005).
4.32	Global Note representing $500,000,000 principal amount of 4.95% Senior Notes due 2010 with attached Guarantee (incorporated by reference to Exhibit 4.47 to Form 10-Q filed November 4, 2005).
4.33	Form of Junior Note, including Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed July 19, 2006).
4.34	Global Note representing $800,000,000 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 8, 2007).
4.35	Form of Global Note representing $400,000,000 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 $700,000,000 principal amount of 6.55% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.37	Amended and Restated Credit Agreement dated as of June 29, 2005, among Cameron Highway Oil Pipeline Company, the Lenders party thereto, and

	SunTrust Bank, as Administrative Agent and Collateral Agent (incorporated by reference to Exhibit 4.1 to Form 8-K filed on July 1, 2005).
4.38	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 the Current Report on Form 8-K filed by Enterprise Products Partners L.P. on May 24, 2007).
4.39	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).
4.40	Purchase Agreement, dated as of July 12, 2006 between Cerrito Gathering Company, Ltd., Cerrito Gas Marketing, Ltd., Encinal Gathering, Ltd., as Sellers, Lewis Energy Group, L.P. as Guarantor, and Enterprise Products Partners L.P., as buyer (incorporated by reference to Exhibit 4.6 to Form 10-Q filed August 8, 2006).

10.1***	Second Amendment to Agreement of Limited Partnership of EPE Unit L.P. dated July 1, 2008 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008).
10.2***	Second Amendment to Agreement of Limited Partnership of EPE Unit II, L.P. dated July 1, 2008 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008).
10.3***	Second Amendment to Agreement of Limited Partnership of EPE Unit III, L.P. dated July 1, 2008 (incorporated by reference to Exhibit 10.3 to the Current Report Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008).
10.4*	Second Amended and Restated Limited Liability Company Agreement of Mont Belvieu Caverns, LLC, dated November 6, 2008 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed by Duncan Energy Partners L.P. on November 10, 2008).
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the September 30, 2008 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, 2008 quarterly report on Form 10-Q.
32.1#	Section 1350 certification of Michael A. Creel for the September 30, 2008 quarterly report on Form 10-Q.
32.2#	Section 1350 certification of W. Randall Fowler for the September 30, 2008 quarterly report on Form 10-Q.

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file number for Enterprise Products Partners L.P., Duncan Energy Partners L.P. and Enterprise GP Holdings L.P. are 1-14323, 1-33266 and 1-32610, respectively.

*** Identifies management contract and compensatory plan arrangements.

\# Filed with this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this Quarterly Report on Form 10-Q to be signed on its behalf by the undersigned thereunto duly authorized, in the City of Houston, State of Texas on November 10, 2008.

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

By: Enterprise Products GP, LLC, as General Partner

By: ___/s/ Michael J. Knesek___________________
Name: Michael J. Knesek
Title: Senior Vice President, Controller
and Principal Accounting Officer
of the General Partner