ENTERPRISE PRODUCTS PARTNERS L P
Form 10-Q
August 11, 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 June 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 434,896,002 common units and 2,262,563 restricted common units of Enterprise Products Partners L.P. outstanding at August 11, 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	June 30, 2008	December 31, 2007
Current assets:		
Cash and cash equivalents	$ 24,710	$ 39,722
Restricted cash	--	53,144
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $14,979 at June 30, 2008 and $21,659 at December 31, 2007	2,525,084	1,930,762
Accounts receivable - related parties	53,323	79,782
Inventories	463,721	354,282
Prepaid and other current assets	263,421	80,193
Total current assets	3,330,259	2,537,885
Property, plant and equipment, net	12,407,006	11,587,264
Investments in and advances to unconsolidated affiliates	869,177	858,339
Intangible assets, net of accumulated amortization of $386,453 at June 30, 2008 and $341,494 at December 31, 2007	888,164	917,000
Goodwill	591,652	591,652
Deferred tax asset	3,015	3,522
Other assets, including restricted cash of $17,871 at December 31, 2007	91,583	112,345
Total assets	$ 18,180,856	$ 16,608,007
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable – trade	$ 346,994	$ 324,999
Accounts payable – related parties	61,009	24,432
Accrued product payables	2,703,391	2,227,489
Accrued expenses	64,990	47,756
Accrued interest	139,456	130,971
Other current liabilities	312,810	289,036
Total current liabilities	3,628,650	3,044,683
Long-term debt: (see Note 9)		
Senior debt obligations – principal	6,499,500	5,646,500
Junior subordinated notes – principal	1,250,000	1,250,000
Other	19,007	9,645
Total long-term debt	7,768,507	6,906,145
Deferred tax liabilities	20,986	21,364
Other long-term liabilities	69,282	73,748
Minority interest	422,664	430,418
Commitments and contingencies		
Partners' equity:		
Limited partners		

Common units (434,896,002 units outstanding at June 30, 2008		
and 433,608,763 units outstanding at December 31, 2007)	6,028,864	5,976,947
Restricted common units (2,265,163 units outstanding at June 30, 2008		
and 1,688,540 units outstanding at December 31, 2007)	20,526	15,948
General partner	123,395	122,297
Accumulated other comprehensive income (see Note 10)	97,982	16,457
Total partners' equity	6,270,767	6,131,649
Total liabilities and partners' equity	$ 18,180,856	$ 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 June 30,		For the Six Months Ended June 30,	
	2008	2007	2008	2007
Revenues:				
Third parties	$ 6,116,868	$ 4,076,573	$ 11,500,702	$ 7,335,185
Related parties	222,747	136,233	523,448	200,475
Total revenues	6,339,615	4,212,806	12,024,150	7,535,660
Costs and expenses:				
Operating costs and expenses:				
Third parties	5,824,684	3,875,050	10,959,268	6,915,583
Related parties	135,254	85,622	311,860	169,568
Total operating costs and expenses	5,959,938	3,960,672	11,271,128	7,085,151
General and administrative costs:				
Third parties	10,490	10,628	13,953	14,203
Related parties	13,486	20,733	31,228	33,788
Total general and administrative costs	23,976	31,361	45,181	47,991
Total costs and expenses	5,983,914	3,992,033	11,316,309	7,133,142
Equity in earnings of unconsolidated affiliates	18,569	(6,211)	33,161	(32)
Operating income	374,270	214,562	741,002	402,486
Other income (expense):				
Interest expense	(95,809)	(71,275)	(187,755)	(134,633)
Interest income	1,002	2,408	2,613	4,443
Other, net	(331)	339	(1,051)	232
Total other expense, net	(95,138)	(68,528)	(186,193)	(129,958)
Income before provision for income taxes and minority interest	279,132	146,034	554,809	272,528
Provision for income taxes	(6,926)	1,860	(10,583)	(6,928)
Income before minority interest	272,206	147,894	544,226	265,600
Minority interest	(8,936)	(5,740)	(21,347)	(11,401)
Net income	$ 263,270	$ 142,154	$ 522,879	$ 254,199
Net income allocation: (see Note 10)				
Limited partners' interest in net income	$ 227,707	$ 113,527	$ 452,869	$ 198,576
General partner interest in net income	$ 35,563	$ 28,627	$ 70,010	$ 55,623
Earning per unit: (see Note 13)				
Basic and diluted income per unit	$ 0.52	$ 0.26	$ 1.03	$ 0.46

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2008	2007	2008	2007
Net income	$ 263,270	$ 142,154	$ 522,879	$ 254,199
Other comprehensive income:				
Cash flow hedges:				
Foreign currency hedge losses	(111)	--	(1,308)	--
Net commodity financial instrument gains (losses)	14,229	(3,121)	107,246	846
Net interest rate financial instrument gains (losses)	4,991	29,752	(21,041)	40,264
Less: Amortization of cash flow financing hedges	(1,593)	(1,180)	(3,183)	(2,269)
Total cash flow hedges	17,516	25,451	81,714	38,841
Foreign currency translation adjustment	498	148	75	549
Change in funded status of Dixie benefit plans, net of tax	--	--	(264)	--
Total other comprehensive income	18,014	25,599	81,525	39,390
Comprehensive income	$ 281,284	$ 167,753	$ 604,404	$ 293,589

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 Six Months Ended June 30, 2008	2007
Operating activities:		
Net income	$ 522,879	$ 254,199
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion in operating costs and expenses	270,184	240,653
Depreciation and amortization in general and administrative costs	5,208	4,259
Amortization in interest expense	(1,112)	201
Equity in earnings of unconsolidated affiliates	(33,161)	32
Distributions received from unconsolidated affiliates	56,010	35,026
Operating lease expense paid by EPCO, Inc.	1,053	1,053
Minority interest	21,347	11,401
Loss (gain) on sale of assets	(852)	5,664
Deferred income tax expense	2,529	4,088
Changes in fair market value of financial instruments	9,580	(302)
Effect of pension settlement recognition	(114)	--
Net effect of changes in operating accounts (see Note 16)	(156,843)	(4,225)
Net cash flows provided by operating activities	696,708	552,049
Investing activities:		
Capital expenditures	(1,091,165)	(1,129,263)
Contributions in aid of construction costs	17,761	48,570
Proceeds from sale of assets	514	1,015
Decrease in restricted cash	71,014	308
Cash used for business combinations	(1)	(785)
Acquisition of intangible assets	(5,126)	--
Investments in unconsolidated affiliates	(19,560)	(294,598)
Advances to unconsolidated affiliates	(5,485)	(12,434)
Cash used in investing activities	(1,032,048)	(1,387,187)
Financing activities:		
Borrowings under debt agreements	3,914,686	3,048,734
Repayments of debt	(3,063,000)	(2,063,374)
Debt issuance costs	(8,649)	(9,261)
Distributions paid to partners	(508,969)	(470,561)
Distributions paid to minority interests	(29,129)	(9,416)
Contributions from Duncan Energy Partners reflected as part of minority interests (see Notes 1 and 2)	--	291,044
Other contributions from minority interests	28	12,506
Net proceeds from issuance of our common units	38,029	35,899
Repurchase of option awards	--	(1,568)
Acquisition of treasury units	(650)	--
Monetization of interest rate hedging financial instruments (see Note 4)	(22,144)	42,269
Cash provided by financing activities	320,202	876,272
Effect of exchange rate changes on cash	126	(390)

Net change in cash and cash equivalents	(15,138)	41,134
Cash and cash equivalents, January 1	39,722	22,619
Cash and cash equivalents, June 30	$ 24,710	$ 63,363

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY
(See Note 10 for Unit History and Detail of Changes in Limited Partners' Equity)
(Dollars in thousands)

	Limited Partners	General Partner	AOCI (see Note 10)	Total
Balance, December 31, 2007	$ 5,992,895	$ 122,297	$ 16,457	$ 6,131,649
Net income	452,869	70,010	--	522,879
Operating leases paid by EPCO, Inc.	1,031	22	--	1,053
Cash distributions to partners	(438,809)	(69,723)	--	(508,532)
Non-cash distributions	(2,688)	(55)	--	(2,743)
Net proceeds from sales of common units	36,676	749	--	37,425
Proceeds from exercise of unit options	598	6	--	604
Unit option reimbursements to EPCO, Inc.	(524)	--	--	(524)
Acquisition of treasury units	(637)	(13)	--	(650)
Change in funded status of Dixie benefit plans, net of tax	--	--	(264)	(264)
Amortization of unit-based awards	7,979	102	--	8,081
Foreign currency translation adjustment	--	--	75	75
Cash flow hedges	--	--	81,714	81,714
Balance, June 30, 2008	$ 6,049,390	$ 123,395	$ 97,982	$ 6,270,767

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 12). 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 consolidated financial statements. The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, we do not 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 six months ended June 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 17 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 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

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. 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.

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 June 30, 2008 and 2007. During each of the six month periods ended June 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 June 30, 2008 and 2007. For each of the six month periods ended June 30, 2008 and 2007, Dixie's net pension benefit costs were $0.3 million. Dixie's net postretirement benefit costs were $0.1 million for each of the three month periods ended June 30, 2008 and 2007. For each of the six month periods ended June 30, 2008 and 2007, Dixie's net postretirement benefit costs were $0.2 million. During the remainder of 2008, Dixie expects to contribute approximately $0.2 million to its postretirement benefit plan and approximately $0.5 million to its pension 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. Expenditures to mitigate or prevent future environmental contamination are capitalized.

At June 30, 2008 and December 31, 2007, our accrued liabilities for environmental remediation projects totaled $22.9 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 June 30, 2008 and December 31, 2007, minority interest includes $285.4 million and $288.6 million, respectively, attributable to third party owners of Duncan Energy Partners. Minority interest expense for the three months ended

June 30, 2008 and 2007 includes \$4.8 million and \$3.3 million, respectively, attributable to third party owners of Duncan Energy Partners. For the six months ended June 30, 2008 and 2007 minority interest expense attributable to third party owners of Duncan Energy Partners

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was $9.1 million and $6.1 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 six months ended June 30, 2007 includes approximately $291 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 derivative 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 derivative instruments, (ii) how derivative 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 derivative 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 derivatives, quantitative disclosures about fair value amounts of and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative 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 or results of operations.

SFAS 162, The Hierarchy of Generally Accepted Accounting Principles. In May 2008, the FASB issued SFAS 162, which establishes a consistent framework, or hierarchy, for selecting the accounting principles used to prepare financial statements of nongovernmental entities in conformity with GAAP. SFAS 162 is effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board (PCAOB) amendments to its Interim Auditing Standards. We do not expect SFAS 162 to have a material impact on the preparation of our consolidated financial statements.

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. Management is currently evaluating the impact that EITF 07-4 will have 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 fiscal years beginning after December 15, 2008. We intend to adopt FSP EITF 03-6-1 effective January 1, 2009 and are currently evaluating the impact of adoption on our consolidated financial statements.

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FSP No. FAS 157-2, Effective Date of FASB Statement No. 157. FSP 157-2 defers the effective date of SFAS 157 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. We are currently evaluating the impact of our adoption of FSP 157-2 effective January 1, 2009 on our consolidated financial statements.

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.

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 life of a recognized intangible asset under SFAS 142, Goodwill and Other Intangible Assets. This change is intended to improve the 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 the asset under SFAS 141(R) and other GAAP. FSP 142-3 is effective for us on January 1, 2009. 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 are evaluating the impact that FSP 142-3 will have on our future financial statements.

Restricted Cash

Restricted cash represents amounts held in connection with our commodity financial instruments portfolio and physical natural gas purchases made on the New York Mercantile Exchange. In addition, at December 31, 2007, restricted cash included amounts held by a third party trustee charged with disbursing proceeds from our Petal GO Zone bond offering. The following table presents the components of our restricted cash balances at the periods indicated:

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

Due to market conditions at June 30, 2008, no cash was restricted to meet commodity exchange deposit requirements with respect to our commodity risk hedging activities and physical natural gas purchases; however, cash may be restricted in the future to maintain our positions as commodity prices fluctuate or deposit requirements change. 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. See Note 4 for information about our hedging activities and related changes in restricted cash balances subsequent to June 30, 2008.

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 cash settled upon vesting.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2008	2007	2008	2007
EPCO 1998 Long-Term Incentive Plan ("1998 Plan")				
Unit options	$ 55	$ 3,916	$ 213	$ 4,109
Restricted units	2,044	2,384	3,552	3,658
Total 1998 Plan (1)	2,099	6,300	3,765	7,767
Enterprise Products 2008 Long-Term Incentive Plan ("2008 LTIP")				
Unit options	14	--	14	--
Total 2008 LTIP	14	--	14	--
Employee Partnerships	1,376	676	2,559	1,178
DEP GP UARs	6	25	6	35
Total consolidated expense	$ 3,495	$ 7,001	$ 6,344	$ 8,980

(1) Amounts presented for the three and six months ended June 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 June 30, 2008 and the issuance and forfeiture of restricted unit awards through June 30, 2008, a total of 768,154 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	(47,500)	$ 20.25		
Forfeited or terminated	(85,000)	$ 26.72		
Outstanding at June 30, 2008	2,182,500	$ 26.29	5.68	$ 4,260
Options exercisable at:				
June 30, 2008	517,500	$ 21.31	4.42	$ 4,260

(1) Aggregate intrinsic value reflects fully vested unit options at June 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 six months ended June 30, 2008 was $0.4 million and $0.5 million, respectively. At June 30, 2008, there was an estimated $2.2 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 2.6 years in accordance with the EPCO administrative services agreement.

During the six months ended June 30, 2008 and 2007, we received cash of $0.6 million and $7.3 million, respectively, from the exercise of unit options. Conversely, our option-related reimbursements to EPCO were $0.5 million and $2.8 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)	718,800	$ 25.64
Forfeited	(72,177)	$ 25.88
Vested	(70,000)	$ 19.35
Restricted units at June 30, 2008	2,265,163	

(1) Determined by dividing the aggregate grant date fair value of awards (including an allowance for forfeitures) by the number of awards issued.
(2) Aggregate grant date fair value of restricted common unit awards issued during 2008 was $18.4 million based on a grant date market price of our common units ranging from $30.38 to $32.31 per unit and an estimated forfeiture rate of 17%.

The total fair value of our restricted unit awards that vested during the three and six months ended June 30, 2008 was $1.3 million and $1.4 million, respectively. As of June 30, 2008, there was $37.8 million of total unrecognized compensation cost related to restricted common units. We will recognize our share of such costs in accordance with the EPCO administrative services agreement. At June 30, 2008, these costs are expected to be recognized over a weighted-average period of 2.6 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 restricted units, phantom units, unit options, 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 June 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 1, 2008	--		
Granted (1)	795,000	$ 30.93	
Outstanding at June 30, 2008	795,000	$ 30.93	5.51

(1) Aggregate grant date fair value of these unit options issued during the second quarter of 2008 was $1.6 million based on a grant date market price of our common units of $30.93 per unit and an estimated forfeiture rate of 17.0%.

At June 30, 2008, there was an estimated $1.5 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 weighted-average period of 3.9 years in accordance with the EPCO administrative services agreement.

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 and 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. See Note 18 regarding amendments to EPE Unit I, EPE Unit II and EPE Unit III, which were effective July 2008.

As of June 30, 2008, there was $26.1 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 administrative services agreement over a weighted-average period of 3.7 years.

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 may make capital contributions to Enterprise Unit in addition to its Initial Contribution. Through July 31, 2008, EPCO Holdings has contributed a total of $51.5 million to Enterprise Unit. EPCO Holdings has no legal obligation to make additional contributions.

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 administrative services agreement as a non-cash expense. We will not reimburse EPCO, Enterprise Unit or any of their affiliates or partners, through the administrative services agreement 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 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 similar to liability awards under SFAS 123(R) since they will be settled with cash. At June 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 (i.e., 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.

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 six interest rate swap agreements outstanding at June 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	6.38% to 5.08%	$100.0 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	5	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 3.64%	$500.0 million

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

The aggregate fair value of the six interest rate swaps at June 30, 2008 was an asset of $8.9 million, with an offsetting decrease 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 June 30, 2008 and 2007 includes a $2.2 million benefit and a $2.3 million loss, respectively, resulting from these interest rate swap agreements. For the six months ended June 30, 2008 and 2007, interest expense reflects a benefit of $1.3 million and a loss of $4.6 million, respectively, from these 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
Interest rate swap portfolio, June 30, 2008	$ 600.0	$ 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.

Cash Flow Hedges – Interest Rate Swaps. Duncan Energy Partners had three floating-to-fixed interest rate swap agreements outstanding at June 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	2.80% 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 $0.9 million and $0.8 million from these swap agreements during the three and six months ended June 30, 2008, respectively. The aggregate fair value of these interest rate swaps at June 30, 2008 and December 31, 2007 was a liability of $4.1 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 $2.4 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, June 30, 2008	$ --	$ 40.4

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

We expect to reclassify $2.1 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 June 30, 2008 and December 31, 2007, the aggregate fair value of those financial instruments utilized in connection with our natural gas marketing activities was an asset of $9.6 million and a liability of $0.3 million, respectively. Our natural gas marketing business and its related use of financial instruments has increased significantly since December 31, 2007. We utilize mark-to-market accounting for substantially all of the 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 June 30, 2008	Losses	$ (6.1)
Three months ended June 30, 2007	Gains	$ 0.9

Six months ended June 30, 2008	Losses	$	(5.4)
Six months ended June 30, 2007	Gains	$	0.5

NGL and petrochemical operations. At June 30, 2008 and December 31, 2007, the aggregate fair value of those financial instruments utilized in connection with our NGL and petrochemical operations was an asset of $82.1 million and a liability of $19.0 million, respectively. The change in fair value between December 31, 2007 and June 30, 2008 is primarily due to an increase in the price of natural gas and 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 lesser number accounted for using mark-to-market accounting.

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 June 30, 2008	Gains	$	13.4
Three months ended June 30, 2007	Gains	$	0.2
Six months ended June 30, 2008 (1)	Gains	$	8.9
Six months ended June 30, 2007	Losses	$	(1.8)

(1) Includes ineffectiveness of $2.7 million (a benefit).

The fair value of the NGL and petrochemical portfolio was a liability of $95.4 million as of August 5, 2008. The change in fair value of this portfolio 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. Our restricted cash balance increased from none at June 30, 2008 to $191.2 million as of August 5, 2008 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. During the three and six months ended June 30, 2008, we recorded minimal gains from these financial instruments.

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 New York Mercantile Exchange). 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 June 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 June 30, 2008 there were no Level 1 financial assets or liabilities.

	Level 2	Level 3	Total
Financial assets:			
Commodity financial instruments	$ 149,905	$ --	$ 149,905
Interest rate financial instruments	8,901	--	8,901
Total	$ 158,806	$ --	$ 158,806
Financial liabilities:			
Commodity financial instruments	$ 53,519	$ 4,669	$ 58,188
Total	$ 53,519	$ 4,669	$ 58,188

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
Ending balance, June 30, 2008	$	(4,669)

(1) Net income includes commodity financial instrument gains of $0.3 million and losses of $1.9 million, respectively, recorded in revenue for the three and six months ended June 30, 2008. There were no unrealized gains included in such amounts.

Note 5. Inventories

Our inventory amounts were as follows at the dates indicated:

		June 30, 2008		December 31, 2007
Working inventory (1)	$	435,686	$	342,589
Forward-sales inventory (2)		28,035		11,693
Total inventory	$	463,721	$	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 $5.51 billion and $3.58 billion for the three months ended June 30, 2008 and 2007, respectively. For the six months ended June 30, 2008 and 2007, our cost of sales were $10.41 billion and $6.36 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 June 30, 2008 and 2007, we recognized LCM adjustments of approximately $0.7 million and $2.1 million, respectively. We recognized LCM adjustments of $4.8 million and $13.1 million for the six months ended June 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	June 30, 2008	December 31, 2007
Plants and pipelines (1)	3-35 (5)	$ 11,703,858	$ 10,884,819
Underground and other storage facilities (2)	5-35 (6)	730,391	720,795
Platforms and facilities (3)	20-31	634,820	637,812
Transportation equipment (4)	3-10	32,981	32,627
Land		50,305	48,172
Construction in progress		1,388,484	1,173,988
Total		14,540,839	13,498,213
Less accumulated depreciation		2,133,833	1,910,949
Property, plant and equipment, net		$ 12,407,006	$ 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 June 30, 2008	For the Three Months Ended June 30, 2007	For the Six Months Ended June 30, 2008	For the Six Months Ended June 30, 2007
Depreciation expense (1)	$ 113,972	$ 99,086	$ 223,815	$ 194,066
Capitalized interest (2)	$ 17,623	$ 20,397	$ 35,735	$ 41,139

(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 six months ended June 30, 2008 decreased by approximately $5.0 million and $10.0 million, respectively, which increased our earnings per unit by $0.01 and $0.02, 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	384
Liabilities settled	(5,473)
Revisions in estimated cash flows	2,308
Accretion expense	1,169
ARO liability balance, June 30, 2008	$ 39,002

Property, plant and equipment at June 30, 2008 and December 31, 2007 includes $9.4 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 11 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 June 30, 2008	June 30, 2008	December 31, 2007
NGL Pipelines & Services:			
Venice Energy Service Company L.L.C. ("VESCO")	13.1%	$ 36,040	$ 40,129
K/D/S Promix, L.L.C. ("Promix")	50%	51,044	51,537
Baton Rouge Fractionators LLC ("BRF")	32.3%	24,575	25,423
White River Hub, LLC ("White River Hub") (1)	50%	14,592	--
Onshore Natural Gas Pipelines & Services:			
Jonah Gas Gathering Company ("Jonah")	19.4%	245,117	235,837
Evangeline (2)	49.5%	4,182	3,490
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36%	59,640	58,423
Cameron Highway Oil Pipeline Company ("Cameron Highway")	50%	256,724	256,588
Deepwater Gateway, L.L.C. ("Deepwater Gateway")	50%	107,876	111,221
Neptune Pipeline Company, L.L.C. ("Neptune")	25.7%	51,442	55,468
Nemo Gathering Company, LLC ("Nemo")	33.9%	789	2,888
Petrochemical Services:			
Baton Rouge Propylene Concentrator, LLC ("BRPC")	30%	13,192	13,282
La Porte (3)	50%	3,964	4,053
Total		$ 869,177	$ 858,339

(1) During the second quarter of 2008 we acquired a 50% 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 June 30, 2008 and December 31, 2007, our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway and Jonah included excess cost amounts totaling $44.4 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 June 30, 2008 and 2007. For each of the six months ended June 30, 2008 and 2007, amortization of such amounts was $1.0 million.

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

	For the Three Months Ended June 30, 2008	For the Three Months Ended June 30, 2007	For the Six Months Ended June 30, 2008	For the Six Months Ended June 30, 2007
NGL Pipelines & Services	$ 1,589	$ 1,089	$ (721)	$ 1,680
Onshore Natural Gas Pipelines & Services	5,458	1,212	11,285	2,241
Offshore Pipelines & Services	11,209	(8,846)	21,927	(4,771)
Petrochemical Services	313	334	670	818
Total	$ 18,569	$ (6,211)	$ 33,161	$ (32)

Summarized Financial Information of Unconsolidated Affiliates

The following table presents 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					
	June 30, 2008			June 30, 2007		
	Revenues	Operating Income	Net Income	Revenues	Operating Income (Loss)	Net Income (Loss)
NGL Pipelines & Services	$ 74,098	$ 8,100	$ 8,207	$ 59,056	$ (779)	$ (74)
Onshore Natural Gas Pipelines & Services	185,974	28,769	27,654	125,132	25,198	24,102
Offshore Pipelines & Services	39,868	23,240	19,889	40,433	24,146	1,894
Petrochemical Services	5,640	1,303	1,308	4,969	1,403	1,429

	Summarized Income Statement Information for the Six Months Ended					
	June 30, 2008			June 30, 2007		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
NGL Pipelines & Services	$ 142,714	$ 8,007	$ 8,261	$ 100,788	$ 2,481	$ 3,755
Onshore Natural Gas Pipelines & Services	303,568	59,724	57,384	234,030	46,813	44,415
Offshore Pipelines & Services	83,092	49,551	45,226	77,626	43,864	14,230
Petrochemical Services	10,996	2,786	2,796	10,522	3,290	3,340

Note 8. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	June 30, 2008			December 31, 2007		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services	$ 523,401	$ (165,658)	$ 357,743	$ 520,025	$ (146,954)	$ 373,071
Onshore Natural Gas Pipelines & Services	476,298	(125,948)	350,350	463,551	(109,399)	354,152
Offshore Pipelines & Services	207,012	(82,662)	124,350	207,012	(73,954)	133,058
Petrochemical Services	67,906	(12,185)	55,721	67,906	(11,187)	56,719
Total	$ 1,274,617	$ (386,453)	$ 888,164	$ 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 June 30,		For the Six Months Ended June 30,	
	2008	2007	2008	2007
NGL Pipelines & Services	$ 9,275	$ 8,801	$ 18,705	$ 18,042
Onshore Natural Gas Pipelines & Services	8,128	8,049	16,550	16,209
Offshore Pipelines & Services	4,279	4,908	8,708	9,988
Petrochemical Services	498	498	996	996
Total	$ 22,180	$ 22,256	$ 44,959	$ 45,235

For the remainder of 2008, amortization expense associated with our intangible assets is currently estimated at $43.4 million.

Goodwill

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

	June 30, 2008	December 31, 2007
NGL Pipelines & Services	$ 153,706	$ 153,706
Onshore Natural Gas Pipelines & Services	282,121	282,121
Offshore Pipelines & Services	82,135	82,135
Petrochemical Services	73,690	73,690
Totals	$ 591,652	$ 591,652

Note 9. Debt Obligations

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

	June 30, 2008	December 31, 2007
EPO senior debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due November 2012	$ 470,000	$ 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	208,000	200,000
Dixie Revolving Credit Facility, variable rate, due June 2010	10,000	10,000
Total principal amount of senior debt obligations	6,499,500	5,646,500
EPO Junior Subordinated Notes A, due August 2066	550,000	550,000
EPO Junior Subordinated Notes B, due January 2068	700,000	700,000
Total principal amount of senior and junior debt obligations	7,749,500	6,896,500
Other, non-principal amounts:		
Change in fair value of debt-related financial instruments (see Note 4)	16,875	14,839
Unamortized discounts, net of premiums	(7,504)	(5,194)
Unamortized deferred net gains related to terminated interest rate swaps (see Note 4)	9,636	--
Total other, non-principal amounts	19,007	9,645
Long-term debt	$ 7,768,507	$ 6,906,145
Standby letters of credit outstanding	$ 1,100	$ 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, we do not have the obligation to make interest or debt payments with respect to such obligations.

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

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, beginning October 1, 2008. Senior Notes N pay interest semi-annually in arrears on January 31 and July 31 of each year, with the first payment made on July 31, 2008. Net proceeds from the issuance of Senior Notes M and N were used to temporarily reduce indebtedness outstanding under the EPO Revolver.

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 June 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 six months ended June 30, 2008.

	Weighted-average interest rate paid
EPO's Multi-Year Revolving Credit Facility	3.96%
Duncan Energy Partners' Revolving Credit Facility	4.51%
Dixie Revolving Credit Facility	3.46%
Petal GO Zone Bonds	2.16%

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	658,000
2012	470,000
Thereafter	5,557,500
Total scheduled principal payments	$ 7,749,500

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 June 30, 2008, (ii) total debt of each unconsolidated affiliate at June 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 June 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 10. 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 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 9.

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 1,219,560 of our common units were issued in connection with the DRIP and the employee unit purchase plan ("EUPP") during the six months ended June 30, 2008. The issuance of these units generated $37.4 million in net proceeds that we used for general partnership purposes.

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

	Number of Common Units Issued	Net Proceeds from Sale of Common Units: 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
Total 2008	1,219,560	$ 36,676	$ 749	$ 37,425

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	--
Units issued in connection with DRIP and EUPP	1,219,560	--	--
Units issued in connection with unit-based awards	19,092	--	--
Restricted units issued	--	718,800	--
Conversion of restricted units to common units	70,000	(70,000)	--
Acquisition of treasury units	(21,413)	--	21,413
Cancellation of treasury units	--	--	(21,413)
Forfeiture of restricted units	--	(72,177)	--
Balance, June 30, 2008	434,896,002	2,265,163	--

In May 2008, 67,500 restricted unit awards vested and were converted to common units. Of this amount, 21,413 were sold back to us by employees to cover related withholding tax requirements. The total cost of these treasury units was approximately $650 thousand, of which $637 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	451,002	1,867	452,869
Operating leases paid by EPCO	1,027	4	1,031
Cash distributions to partners	(437,165)	(1,644)	(438,809)
Non-cash distributions	(2,688)	--	(2,688)
Net proceeds from sales of common units	36,676	--	36,676
Proceeds from exercise of unit options	598	--	598

Unit option reimbursements to EPCO	(524)	--	(524)
Acquisition of treasury units, limited partner share	--	(637)	(637)
Amortization of unit-based awards	2,991	4,988	7,979
Balance, June 30, 2008	$ 6,028,864	$ 20,526	$ 6,049,390

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 $30.9 million and $26.3 million to EPGP during the three months ended June 30, 2008 and 2007, respectively. During the six months ended June 30, 2008 and 2007, we paid incentive distributions of $60.8 million and $51.6 million, respectively, to EPGP.

We paid aggregate distributions to our unitholders and general partner of $509.0 million during the six months ended June 30, 2008. These distributions pertained to the six month period ended March 31, 2008 (i.e., the fourth quarter of 2007 and first quarter of 2008). On August 7, 2008, we paid a quarterly cash distribution of $0.515 per unit with respect to the second quarter of 2008, to unitholders of record at the close of business on July 31, 2008.

Accumulated Other Comprehensive Income

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

	June 30, 2008	December 31, 2007
Commodity financial instruments (1)	$ 85,627	$ (21,619)
Interest rate financial instruments (1)	10,756	34,980
Foreign currency hedges (1)	--	1,308
Foreign currency translation adjustment	1,275	1,200
Pension and postretirement benefit plans (2)	324	588
Total accumulated other comprehensive income	$ 97,982	$ 16,457

(1) See Note 4 for additional information regarding these components of accumulated other comprehensive income.
(2) See Note 2 for additional information regarding pension and postretirement benefit plans.

Note 11. 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 on the sale of assets; 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 June 30,		For the Six Months Ended June 30,	
		2008	2007	2008	2007
Revenues (1)		$ 6,339,615	$ 4,212,806	$ 12,024,150	$ 7,535,660
Less:	Operating costs and expenses (1)	(5,959,938)	(3,960,672)	(11,271,128)	(7,085,151)
Add:	Equity in earnings of unconsolidated affiliates (1)	18,569	(6,211)	33,161	(32)
	Depreciation, amortization and accretion in operating costs and expenses (2)	136,262	121,161	270,184	240,653
	Operating lease expense paid by EPCO (2)	526	527	1,053	1,053
	Loss (gain) on sale of assets in operating costs and expenses (2)	(677)	5,737	(842)	5,664
Total segment gross operating margin		$ 534,357	$ 373,348	$ 1,056,578	$ 697,847

(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 June 30,		For the Six Months Ended June 30,	
	2008	2007	2008	2007
Total segment gross operating margin	$ 534,357	$ 373,348	$ 1,056,578	$ 697,847
Adjustments to reconcile total segment gross operating margin				
to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(136,262)	(121,161)	(270,184)	(240,653)
Operating lease expense paid by EPCO	(526)	(527)	(1,053)	(1,053)
Gain (loss) on sale of assets in operating costs and expenses	677	(5,737)	842	(5,664)
General and administrative costs	(23,976)	(31,361)	(45,181)	(47,991)
Consolidated operating income	374,270	214,562	741,002	402,486
Other expense, net	(95,138)	(68,528)	(186,193)	(129,958)
Income before provision for income taxes, minority interest	$ 279,132	$ 146,034	$ 554,809	$ 272,528

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 June 30,	For the Six Months Ended June 30,

	2008	2007	2008	2007
NGL Pipelines & Services:				
Sale of NGL products	$ 4,216,710	$ 2,923,058	$ 8,278,753	$ 5,114,682
Percent of consolidated revenues	67%	69%	69%	68%
Onshore Natural Gas Pipelines & Services:				
Sale of natural gas	$ 909,864	$ 422,722	$ 1,556,182	$ 783,753