ENTERPRISE PRODUCTS PARTNERS L P
Form 10-Q
November 09, 2007

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF

THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2007

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 x No o

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

Large accelerated filer x Accelerated filer [ ] Non-accelerated filer [ ]

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

Yes o No x

There were 434,736,708 common units of Enterprise Products Partners L.P. outstanding at November 1, 2007. These common units trade on the New York Stock Exchange under the ticker symbol EPD.

ENTERPRISE PRODUCTS PARTNERS L.P.

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PART I. FINANCIAL INFORMATION.

Item 1. ***Financial Statements*****.**

ENTERPRISE PRODUCTS PARTNERS L.P.

UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

ASSETS	**September 30, 2007**	**December 31, 2006**
Current assets:		
Cash and cash equivalents	$ 43,881	$ 22,619
Restricted cash	63,910	23,667
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $21,994 at September 30, 2007 and $23,406 at December 31, 2006	1,532,658	1,306,290
Accounts receivable - related parties	57,540	16,738
Inventories	509,888	423,844
Prepaid and other current assets	167,960	129,000
Total current assets	2,375,837	1,922,158
Property, plant and equipment, net	11,133,395	9,832,547
Investments in and advances to unconsolidated affiliates	854,825	564,559
Intangible assets, net of accumulated amortization of $319,061 at September 30, 2007 and $251,876 at December 31, 2006	928,201	1,003,955
Goodwill	591,644	590,541
Deferred tax asset	2,453	1,855
Other assets	119,650	74,103
Total assets	$ 16,006,005	$ 13,989,718
LIABILITIES AND PARTNERS EQUITY		
Current liabilities:		
Accounts payable trade	$ 326,306	$ 277,070
Accounts payable related parties	21,038	6,785
Accrued product payables	1,719,001	1,364,493
Accrued expenses	48,891	35,763
Accrued interest	100,885	90,865
Other current liabilities	259,882	209,945
Total current liabilities	2,476,003	1,984,921
Long-term debt: (see Note 9)		
Senior debt obligations principal	5,546,568	4,779,068
Junior subordinated notes principal	1,250,000	550,000
Other	(24,580)	(33,478)
Total long-term debt	6,771,988	5,295,590
Deferred tax liabilities	16,966	13,723
Other long-term liabilities	85,388	86,121
Minority interest	430,800	129,130
Commitments and contingencies		
Partners equity:		
Limited partners		
Common units (433,062,984 units outstanding at September 30, 2007 and 431,303,193 units outstanding at December 31, 2006)	6,044,028	6,320,577
Restricted common units (1,673,724 units outstanding at September 30, 2007 and 1,105,237 units outstanding at December 31, 2006)	13,536	9,340

General partner	123,965	129,175
Accumulated other comprehensive income	43,331	21,141
Total partners equity	6,224,860	6,480,233
Total liabilities and partners equity	$ 16,006,005	$ 13,989,718

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.

UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED OPERATIONS

(Dollars in thousands, except per unit amounts)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2007	2006	2007	2006
Revenues:				
Third parties	$ 3,933,157	$ 3,740,162	$ 11,268,342	$ 10,304,580
Related parties	178,839	132,363	379,314	335,872
Total (see Note 11)	4,111,996	3,872,525	11,647,656	10,640,452
Costs and expenses:				
Operating costs and expenses:				
Third parties	3,815,087	3,501,690	10,730,670	9,691,486
Related parties	81,324	83,093	250,892	263,745
Total operating costs and expenses	3,896,411	3,584,783	10,981,562	9,955,231
General and administrative costs:				
Third parties	7,211	5,095	21,414	13,232
Related parties	11,504	10,728	45,292	32,566
Total general and administrative costs	18,715	15,823	66,706	45,798
Total costs and expenses	3,915,126	3,600,606	11,048,268	10,001,029
Equity in income of unconsolidated affiliates	13,960	2,265	13,928	14,306
Operating income	210,830	274,184	613,316	653,729
Other income (expense):				
Interest expense	(85,075)	(62,793)	(219,708)	(177,203)
Interest income	2,300	2,112	6,743	5,228
Other, net	(594)	24	(362)	2,270
Other expense	(83,369)	(60,657)	(213,327)	(169,705)
Income before provision for income taxes, minority interest and the cumulative effect of change in accounting principle	127,461	213,527	399,989	484,024
Provision for income taxes	(2,073)	(3,285)	(9,001)	(12,449)
Income before minority interest and the cumulative effect of change in accounting principle	125,388	210,242	390,988	451,575
Minority interest	(7,782)	(1,940)	(19,183)	(4,676)
Income before the cumulative effect of change in accounting principle	117,606	208,302	371,805	466,899
Cumulative effect of change in accounting principle (see Note 2)	--	--	--	1,475
Net income	$ 117,606	$ 208,302	$ 371,805	$ 468,374
Net income allocation: (see Note 13)				
Limited partners interest in net income	$ 88,408	$ 182,198	$ 286,984	$ 397,759
General partner interest in net income	$ 29,198	$ 26,104	$ 84,821	$ 70,615
Earning per unit: (see Note 13)				
Basic and diluted income per unit				
before change in accounting principle	$ 0.20	$ 0.43	$ 0.66	$ 0.97
Basic and diluted income per unit	$ 0.20	$ 0.43	$ 0.66	$ 0.97

See Notes to Unaudited Condensed Consolidated Financial Statements.

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ENTERPRISE PRODUCTS PARTNERS L.P.

UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED

COMPREHENSIVE INCOME

(Dollars in thousands)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Net income	$ 117,606	$ 208,302	$ 371,805	$ 468,374
Other comprehensive income:				
Cash flow hedges:				
Net commodity financial instrument gains (losses)	(22,292)	12,580	(21,446)	4,880
Foreign currency hedge gains	2,879	--	2,879	--
Net interest rate financial instrument gains (losses)	373	(1,638)	40,637	--
Less: Amortization of cash flow financing hedges	(1,096)	(1,065)	(3,365)	(3,158)
Total cash flow hedges	(20,136)	9,877	18,705	1,722
Foreign currency translation adjustment	1,832	--	2,381	--
Total other comprehensive income	(18,304)	9,877	21,086	1,722
Comprehensive income	$ 99,302	$ 218,179	$ 392,891	$ 470,096

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.

UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS

(Dollars in thousands)

	For the Nine Months Ended September 30,	
	2007	**2006**
Operating activities:		
Net income	$ 371,805	$ 468,374
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion in operating costs and expenses	374,522	325,180
Depreciation and amortization in general and administrative costs	7,129	5,482
Amortization in interest expense	432	641
Equity in income of unconsolidated affiliates	(13,928)	(14,306)
Distributions received from unconsolidated affiliates	52,343	27,085
Cumulative effect of change in accounting principle	--	(1,475)
Operating lease expense paid by EPCO, Inc.	1,579	1,582
Minority interest	19,183	4,676
Loss (gain) on sale of assets	5,445	(3,401)
Deferred income tax expense	5,542	12,378
Changes in fair market value of financial instruments	3,511	(41)
Net effect of changes in operating accounts (see Note 16)	110,272	159,849
Net cash flows provided by operating activities	937,835	986,024
Investing activities:		
Capital expenditures	(1,684,455)	(1,040,341)
Contributions in aid of construction costs	52,462	63,670
Proceeds from sale of assets	1,933	3,043
Increase in restricted cash	(79,535)	(6,203)
Cash used for business combinations	(785)	(144,973)
Investments in unconsolidated affiliates	(318,491)	(100,312)
Advances from (to) unconsolidated affiliates	(10,624)	7,878
Cash used in investing activities	(2,039,495)	(1,217,238)
Financing activities:		
Borrowings under debt agreements	4,926,858	2,648,285
Repayments of debt	(3,459,881)	(2,587,000)
Debt issuance costs	(15,281)	--
Distributions paid to partners	(711,739)	(616,261)
Distributions paid to minority interests	(20,485)	(4,643)
Net proceeds from initial public offering of Duncan Energy Partners reflected as a contribution from minority interests (see Notes 1 and 2)	290,466	--
Other contributions from minority interests	12,506	23,091
Settlement of treasury lock contracts	48,895	--
Repurchase of restricted units and options	(1,568)	--
Net proceeds from issuance of our common units	52,804	843,044
Cash provided by financing activities	1,122,575	306,516
Effect of exchange rate changes on cash flows	347	--
Net change in cash and cash equivalents	20,915	75,302
Cash and cash equivalents, January 1	22,619	42,098
Cash and cash equivalents, September 30	$ 43,881	$ 117,400

See Notes to Unaudited Condensed Consolidated Financial Statements.

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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	Total
Balance, December 31, 2006	$ 6,329,917	$ 129,175	$ 21,141	$ 6,480,233
Net income	286,984	84,821	--	371,805
Operating leases paid by EPCO, Inc.	1,548	31	--	1,579
Cash distributions to partners	(617,260)	(91,567)	--	(708,827)
Net proceeds from sales of common units	44,089	1,210	--	45,299
Proceeds from exercise of unit options	7,451	213	--	7,664
Repurchase of restricted units and options	(1,568)	--	--	(1,568)
Unit option reimbursements to EPCO, Inc.	(2,859)	(58)	--	(2,917)
Change in funded status of pension and postretirement plans, net of tax	--	--	1,104	1,104
Amortization of equity awards	9,262	140	--	9,402
Foreign currency translation adjustment	--	--	2,381	2,381
Cash flow hedges	--	--	18,705	18,705
Balance, September 30, 2007	$ 6,057,564	$ 123,965	$ 43,331	$ 6,224,860

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 Prod 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), as successor in interest by merger to Enterprise Products Operating L.P. We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our general partner, referred to as Enterprise Products GP). Enterprise Products GP 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, Enterprise Products GP, Enterprise GP Holdings, EPE Holdings and Dan Duncan LLC are affiliates under the common control of Dan L. Duncan, the Chairman and controlling shareholder of EPCO.

References to TEPPCO mean TEPPCO Partners, L.P., a publicly traded affiliate, the 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 ETE 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 ETE GP and Energy Transfer Equity.

References to Employee Partnerships mean EPE Unit L.P. (EPE Unit I), EPE Unit II, L.P. (EPE Unit II) and EPE Unit III, L.P. (EPE Unit III), 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.

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 nine months ended September 30, 2007 are not necessarily indicative of results expected for the full year.

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.

Essentially all of our assets, liabilities, revenues and expenses are recorded at EPO s level in our consolidated financial statements. We act 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 accounting principles generally accepted in the United States of America (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, 2006 (Commission File No. 1-14323).

Note 2. General Accounting Policies and Related Matters

Accounting for Employee Benefit Plans

Dixie Pipeline Company (Dixie), a consolidated subsidiary, employs the personnel that operate its pipeline system and certain of these employees are eligible to participate in Dixie s defined contribution plan and pension and postretirement benefit plans. Due to the immaterial nature of Dixie s employee benefit plans to our consolidated financial position, results of operations and cash flows, our discussion is limited to the following:

Defined Contribution Plan. Dixie contributed $0.1 million to its company-sponsored defined contribution plan during each of the three month periods ended September 30, 2007 and 2006. During each of the nine month periods ended September 30, 2007 and 2006, 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 and $0.2 million for the three months ended September 30, 2007 and 2006, respectively. For the nine months ended September 30, 2007 and 2006, Dixie s net pension benefit costs were $0.4 million and $0.5 million, respectively. Dixie s net postretirement benefit costs were $0.1 million for each of the three month periods ended September 30, 2007 and 2006. For the nine months ended September 30, 2007 and 2006, Dixie s net postretirement benefit costs were $0.3 million and $0.2 million, respectively. During the remainder of 2007, Dixie expects to contribute approximately $0.1 million to its postretirement benefit plan and approximately $1.2 million to its pension plan.

Consolidation Policy

We evaluate our financial interests in business enterprises 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 consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of all material intercompany accounts and transactions. We also consolidate other entities and ventures in which we possess a controlling financial interest as well as partnership interests where we are the sole general partner of the partnership.

If the entity 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 entity 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 entity s operating and financial policies. Our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates are eliminated in consolidation 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 entity does not provide us with either control or significant influence, we account for the investment using the cost method.

Cumulative Effect of Change in Accounting Principle

In January 2006, we adopted the provisions of Statement of Financial Accounting Standards (SFAS) 123(R), Share-Based Payment. Upon adoption of this accounting standard, we recognized, as a benefit, a cumulative effect of change in accounting principle of $1.5 million.

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 September 30, 2007 and December 31, 2006, our accrued liabilities for environmental remediation projects totaled $27.9 million and $24.2 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.

In February 2007, we entered into a settlement with a third party, which resulted in our receiving, in part, $6.5 million in cash from such third party. We reserved such cash payment to fund anticipated future environmental remediation costs associated with certain assets that we had acquired from the third party. Previously, the third party had been obligated to indemnify us for such costs. As a result of the settlement, this indemnification was terminated.

Estimates

Preparing our Unaudited Condensed Consolidated Financial Statements in conformity with GAAP requires management to make estimates and assumptions that affect reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. 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.

Income Taxes

We are organized as a pass-through entity for income tax purposes. As a result, our partners are responsible for federal income taxes on their share of our taxable income. For the three and nine months ended September 30, 2007 and 2006, our provision for income taxes is applicable to state tax obligations under the Revised Texas Franchise Tax and certain federal and state tax obligations of Seminole Pipeline Company (Seminole) and Dixie.

In accordance with Financial Accounting Standards Board Interpretation (FIN) 48, Accounting for Uncertainty in Income Taxes, we must recognize the tax effects of any uncertain tax positions we may adopt, if the position taken by us is more likely than not sustainable. If a tax position meets such criteria, the tax effect to be recognized by us would be the largest amount of benefit with more than a 50% chance of being realized upon settlement. This guidance was effective January 1, 2007, and our adoption of this guidance had no material impact on our financial position, results of operations or cash flows.

Minority Interest

As presented in our Unaudited Condensed Consolidated Balance Sheets, minority interest represents third-party ownership interests in the net assets of our consolidated subsidiaries. For financial reporting purposes, the assets and liabilities of our majority owned subsidiaries are consolidated with those of our own, with any third-party ownership in such amounts presented as minority interest. Effective February 1, 2007, the public owners of Duncan Energy Partners common units are presented as a minority interest in our consolidated financial statements.

Minority interest, as reflected on our September 30, 2007 balance sheet, includes $290.2 million attributable to third party owners of Duncan Energy Partners and the remainder to our other consolidated affiliates.

Minority interest expense for the three and nine months ended September 30, 2007 includes $3.2 million and $9.4 million, respectively, attributable to third party owners of Duncan Energy Partners. The remaining minority interest expense amounts for these periods in 2007 and likewise those for 2006 are attributable to our other consolidated affiliates.

Contributions from minority interests for the nine months ended September 30, 2007 includes $290.5 million received from third parties in connection with the initial public offering of Duncan Energy Partners in February 2007.

Recent Accounting Developments

SFAS 157, Fair Value Measurements defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS 157 applies only to fair-value measurements that are already required or permitted by other accounting standards and is expected to increase the consistency of those measurements. SFAS 157 emphasizes that fair value is a market-based measurement that should be determined based on the assumptions that market participants would use in pricing an asset or liability. Companies will be required to disclose the extent to which fair value is used to measure assets and liabilities, the inputs used to develop the measurements and the effect of certain of the measurements on earnings (or changes in net assets) for the period. SFAS 157 is effective for fiscal years beginning after November 15, 2007, and we are required to adopt SFAS 157 as of January 1, 2008.

SFAS 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115 permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected would be reported in net income. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes the company elects for similar types of assets and liabilities. SFAS 159 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating this statement and have not yet determined the impact of such on our financial statements.

Note 3. Accounting for Unit-Based Awards

We account for unit-based awards in accordance with SFAS 123(R). 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. Under SFAS 123(R), 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 compensation amounts by plan during each of the periods indicated:

	For the Three Months Ended September 30,		**For the Nine Months Ended September 30,**	
	2007	**2006**	**2007**	**2006**
EPCO 1998 Long-Term Incentive Plan (1998 Plan)				
Unit options	$ 139	$ 193	$ 4,248	$ 508
Restricted units	1,981	1,032	5,639	3,761
Total 1998 Plan (1)	2,120	1,225	9,887	4,269
Employee Partnerships	1,364	517	2,542	1,646
DEP Holdings, LLC Unit Appreciation Rights	23	--	58	--
Total consolidated expense	$ 3,507	$ 1,742	$ 12,487	$ 5,915

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

1998 Plan

The 1998 Plan provides for the issuance of up to 7,000,000 of our common units. After giving effect to outstanding option awards at September 30, 2007 and the issuance and forfeiture of restricted unit awards through September 30, 2007, a total of 1,271,456 additional common units could be issued under the 1998 Plan.

Unit options. 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 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, 2006	2,416,000	$ 23.32		
Granted (2)	895,000	$ 30.63		
Exercised	(241,000)	$ 19.06		
Settled (3)	(710,000)	$ 24.35		
Outstanding at September 30, 2007	2,360,000	$ 26.22	7.98	$ 2,861
Options exercisable at:				
September 30, 2007	350,000	$ 22.08	4.26	$ 2,861

(1) Aggregate intrinsic value reflects fully vested unit options at September 30, 2007.

(2) The total grant date value of these awards was $2.4 million based on the following assumptions: (i) expected life of the option of seven years; (ii) weighted-average risk-free interest rate of 4.80%; (iii) weighted-average expected distribution yield on our common units of 8.40%; and (iv) weighted-average expected unit price volatility on our common units of 23.22%.

(3) Reflects the settlement of options in connection with the resignation of our former chief executive officer.

The total intrinsic value of option awards exercised during the three and nine months ended September 30, 2007 was $0.1 million and $2.9 million, respectively. At September 30, 2007, there was an estimated $3.1 million of total unrecognized compensation cost related to nonvested option awards granted under the 1998 Plan. We expect to recognize this amount over a weighted-average period of 3.1 years. We will recognize our share of these costs in accordance with the EPCO administrative services agreement.

During the nine months ended September 30, 2007 and 2006, we received cash of $7.7 million and $4.0 million, respectively, from the exercise of option awards granted under the 1998 Plan. Conversely, our option-related reimbursements to EPCO were $2.9 million and $1.7 million, respectively.

Restricted units. 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 unit awards for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit(1)
Restricted units at December 31, 2006	1,105,237	
Granted (2)	704,740	$ 25.57
Vested	(500)	$ 25.70
Forfeited	(22,700)	$ 23.86
Settled (3)	(113,053)	$ 23.24
Restricted units at September 30, 2007	1,673,724	

(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 unit awards issued during 2007 was $18.0 million based on a grant date market price of our common units ranging from $28.00 to $30.96 per unit and estimated forfeiture rates ranging from 4.6% to 17.0%.

(3) Reflects the settlement of restricted units in connection with the resignation of our former chief executive officer.

The total fair value of restricted unit awards that vested during the three and nine months ended September 30, 2007 was nominal. At September 30, 2007, there was an estimated $27.5 million of total unrecognized compensation cost related to restricted unit awards granted under the 1998 Plan, which we expect to recognize over a weighted-average period of 2.6 years. We will recognize our share of such costs 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 three Employee Partnerships. 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 2005. EPE Unit III was formed in May 2007. For a detailed description of EPE Unit I and EPE Unit II, see our annual report on Form 10-K for the year ended December 31, 2006.

At September 30, 2007, there was an estimated $28.7 million of combined unrecognized compensation cost related to the Employee Partnerships. We will recognize our share of these costs in accordance with the EPCO administrative services agreement over a weighted-average period of 4.2 years.

EPE Unit III. EPE Unit III owns 4,421,326 units of Enterprise GP Holdings contributed to it by a private company affiliate of EPCO, which, in turn, was made the Class A limited partner of EPE Unit III. The units of Enterprise GP Holdings contributed by the Class A limited partner had a fair value of $170.0 million on the date of contribution (the Class A limited partner capital base). Certain EPCO employees were issued Class B limited partner interests and admitted as Class B limited partners of EPE Unit III without any capital contribution. The profits interest awards (i.e., Class B limited partner interests) in EPE Unit III entitle the holder to participate in the appreciation in value of Enterprise GP Holdings units owned by EPE Unit III.

Unless otherwise agreed to by EPCO, the Class A limited partner and a majority in interest of the Class B limited partners of EPE Unit III, EPE Unit III will be liquidated upon the earlier of: (i) May 7, 2012 or (ii) a change in control of Enterprise GP Holdings or its general partner. EPE Unit III 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 EPE Unit III from Enterprise GP Holdings will be distributed to the Class A limited partner until it has received an amount equal to the pro rata Class A preferred return (as defined below), and any remaining distributions received by EPE Unit III will be distributed to the Class B limited partners. The Class A preferred return equals 3.797% per annum, of the Class A limited partner s capital base. The Class A limited partner s capital base equals approximately $170.0 million plus any unpaid Class A preferred return from prior periods, less any distributions made by EPE Unit III of proceeds from the sale of Enterprise GP Holdings units owned by EPE Unit III (as described below).

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

§ Sale Proceeds If EPE Unit III sells any of the 4,421,326 units of Enterprise GP Holdings that it 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.

The Class B limited partner interests in EPE Unit III 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 May 7, 2012, with customary exceptions for death, disability and certain retirements. The risk of

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forfeiture associated with the Class B limited partner interests in EPE Unit III will also lapse upon certain change of control events.

DEP Holdings, LLC Unit Appreciation Rights

The non-employee directors of DEP Holdings, LLC, the general partner of Duncan Energy Partners (DEPGP), 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. The compensation expense associated with these awards is recognized by DEPGP, which is our consolidated subsidiary. The 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. If a director resigns prior to vesting, his UAR awards are forfeited. These UARs are accounted for similar to liability awards under SFAS 123(R) since they will be settled with cash.

As of September 30, 2007, a total of 90,000 UARs had been granted to non-employee directors of DEPGP that cliff vest in 2012. If a director resigns prior to vesting, his UAR awards are forfeited. The grant date fair value with respect to these UARs is based on an Enterprise GP Holdings unit price of $36.68.

Note 4. Financial Instruments

We are exposed to financial market risks, including changes in commodity prices and interest rates. In addition, we are exposed to fluctuations in exchange rates between the U.S. dollar and Canadian dollar. 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) 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. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes.

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 exposure 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 eleven interest rate swap agreements outstanding at September 30, 2007 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 Amount**
Senior Notes B, 7.50% fixed rate, due Feb. 2011	1	Jan. 2004 to Feb. 2011	Feb. 2011	7.50% to 8.65%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.38% to 7.19%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 6.30%	$600 million

Senior Notes K, 4.95% fixed rate, due June 2010	2	Aug. 2005 to June 2010	June 2010	4.95% to 5.80%	$200 million

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

The total fair value of these eleven interest rate swaps at September 30, 2007 and December 31, 2006, was a liability of $19.7 million and $29.1 million, respectively, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the three months ended September 30, 2007 and 2006 includes a $2.3 million and $1.9 million loss from these swap agreements, respectively. For the nine months ended September 30, 2007 and 2006, interest expense reflects a loss of $6.9 million and $2.8 million from these swap agreements, respectively.

Cash Flow Hedges Interest Rate Swaps. In September 2007, Duncan Energy Partners executed three floating-to-fixed interest rate swaps having a combined notional value of $175.0 million. The purpose of these financial instruments, which are accounted for as cash flow hedges, is to reduce the sensitivity of Duncan Energy Partners earnings to variable interest rates charged under its revolving credit facility. The fair value of these swaps at September 30, 2007 and the benefit recognized from them in September 2007 was nominal.

Cash Flow Hedges Treasury Locks. At times, we may use treasury lock financial instruments to hedge the underlying U.S. treasury rates related to our anticipated issuances of debt. Gains or losses on the termination of such instruments are amortized to earnings using the effective interest method over the estimated term of the underlying fixed-rate debt. The following table summarizes changes in our treasury lock portfolio since December 31, 2006 (dollars in millions):

	Notional Amount	**Cash Gain (Loss)**
Treasury lock portfolio, December 31, 2006 (1)	$ 562.5	$ --
First quarter of 2007 additions to portfolio (1)	437.5	--
Second quarter of 2007 terminations (2)	(875.0)	42.3
Third quarter of 2007 additions to portfolio (3)	875.0	--
Third quarter of 2007 terminations (4)	(750.0)	6.6
Treasury lock portfolio, September 30, 2007 (5)	$ 250.0	$ 48.9

(1) EPO entered into these transactions related to its anticipated issuances of debt in 2007.

(2) Terminations relate to the issuance of the Junior Notes B ($500.0 million) and Senior Notes L ($375.0 million). Of the $42.3 million gain, $10.6 million relates to the Junior Notes B and the remainder to the Senior Notes L and its successor debt.

(3) EPO entered into these transactions related to its issuance of the Senior Notes L (including its successor debt) in August 2007 ($500.0 million) and anticipated issuance of debt during the first half of 2008 ($250.0 million)

(4) Terminations relate to the issuance of the Senior Notes L and its successor debt.

(5) The fair value of these financial instruments at September 30, 2007 was $2.9 million.

Since September 30, 2007, we have executed an additional $350.0 million in notional amount of treasury lock financial instruments.

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 hedge 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 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.

At September 30, 2007 and December 31, 2006, we had a limited number of commodity financial instruments in our portfolio, which primarily consisted of cash flow hedges. The fair value of our commodity financial instrument portfolio at September 30, 2007 and December 31, 2006 was a liability of $23.4 million and $3.2 million, respectively. During the three and nine months ended September 30, 2007, we recorded an expense of $10.5 million and $11.9 million, respectively, related to our commodity financial instruments. During the three and nine months ended September 30, 2006, we recorded $7.8 million and $2.4 million, respectively, of expense related to our commodity financial instruments.

Foreign Currency Hedging Program

We own an NGL marketing business located in Canada and have entered into a construction agreement where payments are indexed to the Canadian dollar. 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. We use mark-to-market accounting for those foreign exchange contracts associated with our Canadian NGL marketing business. The duration of these contracts is typically one month. At September 30, 2007, $1.1 million of these exchange contracts were outstanding, all of which expired in October 2007. The foreign exchange contracts associated with our construction activities are accounted for using hedge accounting. At September 30, 2007, the fair value of these contracts was $2.9 million. These contracts settle through May 2008.

Note 5. Inventories

Our inventory amounts were as follows at the dates indicated:

	September 30, 2007	**December 31, 2006**
Working inventory (1)	$ 496,030	$ 387,973
Forward-sales inventory (2)	13,858	35,871
Total inventory	$ 509,888	$ 423,844

(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 was $3.5 billion and $3.2 billion for the three months ended September 30, 2007 and 2006, respectively. For the nine months ended September 30, 2007 and 2006, our cost of sales was $9.9 billion and $9.0 billion, respectively.

Due to fluctuating commodity prices in the NGL, natural gas and petrochemical industry, we recognize lower of cost or market (LCM) adjustments when the carrying value of our inventories exceed their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized. For the three months ended September 30, 2007 and 2006, we recognized LCM adjustments of approximately $0.2 million and $5.7 million, respectively. We recognized LCM adjustments of $13.3 million and $17.7 million for the nine months ended September 30, 2007 and 2006, respectively.

Note 6. Property, Plant and Equipment

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

	Estimated Useful Life in Years	**September 30, 2007**	**December 31, 2006**
Plants and pipelines (1)	3-35 (5)	$ 10,228,684	$ 8,774,683
Underground and other storage facilities (2)	5-35 (6)	708,827	596,649
Platforms and facilities (3)	20-31	634,980	161,839
Transportation equipment (4)	3-10	30,558	27,008
Land		45,353	40,010
Construction in progress		1,287,350	1,734,083
Total		12,935,752	11,334,272
Less accumulated depreciation		1,802,357	1,501,725
Property, plant and equipment, net		$ 11,133,395	$ 9,832,547

(1) Plants and pipelines include processing plants; NGL, petrochemical, oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment; and related assets.

(2) Underground and other storage facilities include underground product storage caverns; storage tanks; water wells; and related assets.

(3) Platforms and facilities include offshore platforms and related facilities and other associated assets.

(4) Transportation equipment includes vehicles and similar assets used in our operations.

(5) In general, the estimated useful lives of major components of this category are as follows: processing plants, 20-35 years; pipelines, 18-35 years (with some equipment at 5 years); terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings 20-35 years; and laboratory and shop equipment, 5-35 years.

(6) In general, the estimated useful lives of major components of this category are as follows: underground storage facilities, 20-35 years (with some components at 5 years); storage tanks, 10-35 years; and water wells, 25-35 years (with some components at 5 years).

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

	For the Three Months Ended September 30,		**For the Nine Months Ended September 30,**	
	2007	**2006**	**2007**	**2006**
Depreciation expense (1)	$ 108,692	$ 88,929	$ 302,758	$ 259,361
Capitalized interest (2)	$ 18,656	$ 15,015	$ 59,795	$ 36,570

(1) Depreciation expense is a component of operating 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.

Asset retirement obligations

An ARO is a legal obligation 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, 2006:

ARO liability balance, December 31, 2006	$ 24,403
Liabilities incurred	1,673
Liabilities settled	(2,260)
Revisions in estimated cash flows	8,693
Accretion expense	3,397
ARO liability balance, September 30, 2007 (unaudited)	$ 35,906

Property, plant and equipment at September 30, 2007 includes $11.6 million of asset retirement costs capitalized as an increase in the associated long-lived asset. Also, as of September 30, 2007, we estimate that accretion expense will approximate $0.5 million for the last three months of 2007, $2.2 million for 2008, $2.0 million for 2009, $2.1 million for 2010 and $2.3 million for 2011.

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 September 30, 2007	**Investments in and advances to unconsolidated affiliates at**	
		September 30, 2007	**December 31, 2006**
NGL Pipelines & Services:			
Venice Energy Service Company L.L.C. (VESCO)	13.1%	$ 44,071	$ 39,618
K/D/S Promix, L.L.C. (Promix)	50%	51,186	46,140
Baton Rouge Fractionators LLC (BRF)	32.3%	25,037	25,471
Onshore Natural Gas Pipelines & Services:			
Jonah Gas Gathering Company (Jonah)	19.4%	224,374	120,370
Evangeline (1)	49.5%	3,968	4,221
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. (Poseidon)	36%	60,207	62,324
Cameron Highway Oil Pipeline Company (Cameron Highway) (2)	50%	257,551	60,216
Deepwater Gateway, L.L.C. (Deepwater Gateway)	50%	111,866	117,646
Neptune Pipeline Company, L.L.C. (Neptune)	25.7%	55,906	58,789
Nemo Gathering Company, LLC (Nemo) (3)	33.9%	2,610	11,161
Petrochemical Services:			
Baton Rouge Propylene Concentrator, LLC (BRPC)	30%	13,712	13,912
La Porte (4)	50%	4,337	4,691
Total		$ 854,825	$ 564,559

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

(2) During the second quarter of 2007, we contributed $216.5 million to Cameron Highway to fund our portion of the repayment of Cameron Highway s debt. See Cameron Highway discussion within this Note 7.

(3) During the nine months ended September 30, 2007, we recorded a $7.0 million non-cash impairment charge attributable to our investment in Nemo. See Nemo discussion within this Note 7.

(4) 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 an ownership interest in a company exceeds the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our investments in and advances to unconsolidated affiliates. At September 30, 2007 and December 31, 2006, our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway, Nemo and Jonah included excess cost amounts totaling $42.9 million and $38.7 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. We amortize such excess cost amounts as a reduction in equity earnings. Amortization of such excess cost amounts was $0.5 million during each of the three month periods ended September 30, 2007 and 2006. For the nine months ended September 30, 2007 and 2006, amortization of such amounts was $1.5 million and $1.6 million, respectively.

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

	For the Three Months Ended September 30,		**For the Nine Months Ended September 30,**	
	2007	**2006**	**2007**	**2006**
NGL Pipelines & Services	$ 2,684	$ 1,422	$ 4,364	$ 4,864
Onshore Natural Gas Pipelines & Services	2,351	794	4,592	2,300
Offshore Pipelines & Services (1) (2) (3)	8,557	(330)	3,786	6,373
Petrochemical Services	368	379	1,186	769
Total	$ 13,960	$ 2,265	$ 13,928	$ 14,306

(1) Equity earnings from Nemo for the nine months ended September 30, 2007 include a $7.0 million non-cash impairment charge. See Nemo discussion within this Note 7.

(2) Equity earnings from Cameron Highway for the nine months ended September 30, 2007 were reduced by a charge of $8.8 million for costs associated with the early retirement of Cameron Highway s debt.

(3) Equity earnings from Neptune for the three and nine months ended September 30, 2006 include a $7.4 million non-cash impairment charge.

Summarized Financial Information of Unconsolidated Affiliates

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

	Summarized Income Statement Information for the Three Months Ended					
	September 30, 2007			**September 30, 2006**		
	Revenues	**Operating Income**	**Net Income**	**Revenues**	**Operating Income (Loss)**	**Net Income (Loss)**
NGL Pipelines & Services (1)	$ 49,579	$ 15,435	$ 16,118	$ 63,086	$ (4,031)	$ (3,644)
Onshore Natural Gas Pipelines & Services	126,042	24,659	23,447	127,880	20,664	17,970
Offshore Pipelines & Services	39,331	21,363	19,974	41,245	21,311	14,138
Petrochemical Services	4,894	1,480	1,492	5,029	1,527	1,560

(1) During the three months ended September 30, 2006, VESCO earnings were reduced due to the lingering effects of Hurricane Katrina, including significant storm-related repair expenses.

	Summarized Income Statement Information for the Nine Months Ended					
	September 30, 2007			**September 30, 2006**		
	Revenues	**Operating Income**	**Net Income**	**Revenues**	**Operating Income (Loss)**	**Net Income (Loss)**
NGL Pipelines & Services (1)	$ 150,367	$ 17,916	$ 19,873	$ 143,592	$ (28,394)	$ (27,107)
Onshore Natural Gas Pipelines & Services	360,072	71,472	67,862	354,304	77,826	70,208
Offshore Pipelines & Services	116,957	65,227	34,204	112,495	52,407	30,622
Petrochemical Services	15,416	4,770	4,832	14,454	3,358	3,435

(1) During the nine months ended September 30, 2006, VESCO earnings were reduced due to the lingering effects of Hurricane Katrina, including significant storm-related repair expenses.

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Cameron Highway. We own a 50.0% interest in Cameron Highway, which owns a crude oil pipeline that gathers production from deepwater areas of the Gulf of Mexico, primarily the Southern Green Canyon area, for delivery to refineries and terminals in southeast Texas. In May 2007, we made an approximate $191.0 million cash contribution to Cameron Highway. This capital contribution, along with an equal amount contributed by our joint venture partner in Cameron Highway, was used by Cameron Highway to repay $365.0 million outstanding under its Senior Notes A and $14.1 million of related make-whole premiums and accrued interest. In June 2007, we and our joint venture partner in Cameron Highway made an additional capital contribution of approximately $25.5 million each. These capital contributions were used by Cameron Highway to repay its Series B notes on June 7, 2007. The amount of the repayment was $50.9 million, which included $0.9 million of related make-whole premiums and accrued interest. As a result of these events, Cameron Highway no longer has any outstanding debt.

Nemo. Nemo was formed in 1999 to construct, own and operate the Nemo Gathering System, a 24-mile natural gas gathering system in the Gulf of Mexico offshore Louisiana. The Nemo Gathering System, which began operations in 2001, gathers natural gas from certain developments in the Green Canyon area of the Gulf of Mexico to a pipeline interconnect with the Manta Ray Gathering System. Due to a recent decrease in throughput volumes on the Nemo Gathering System, we evaluated our 33.9% investment in Nemo for impairment during the second quarter of 2007. The decrease in throughput volumes is primarily due to underperformance of certain fields and natural depletion.

At December 31, 2006, the carrying value of our investment in Nemo was $11.2 million, which included $0.6 million of excess cost related to its original acquisition in 2001. Our review of Nemo s estimated future cash flows during the second quarter of 2007 indicated that the carrying value of our investment exceeded its fair value, which resulted in a non-cash impairment charge of $7.0 million. This loss is recorded as a component of Equity in income of unconsolidated affiliates in our Unaudited Condensed Statements of Consolidated Operations for the nine months ended September 30, 2007. Equity earnings from our investment in Nemo are classified under our Offshore Pipelines & Services business segment. After recording this impairment charge, the carrying value of our investment in Nemo at September 30, 2007 was $2.6 million, which reflects $0.6 million in losses and $2.1 million of distributions we recorded during the first nine months of 2007.

Our investment in Nemo was written down to fair value, which management prepared using recognized business valuation techniques. The fair value analysis is based upon management s expectation of future cash flows. Such expectation of future cash flows incorporates industry information and assumptions made by management. For example, the review of Nemo included management estimates regarding the remaining natural gas reserves of producers served by the Nemo Gathering System. If the assumptions underlying our fair value analysis change and expected cash flows are reduced, additional impairment charges may result.

Note 8. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	September 30, 2007			December 31, 2006		
	Gross Value	**Accum. Amort.**	**Carrying Value**	**Gross Value**	**Accum. Amort.**	**Carrying Value**
NGL Pipelines & Services (1)	$ 520,025	$ (137,446)	$ 382,579	$ 528,594	$ (110,644)	$ 417,950
Onshore Natural Gas Pipelines & Services	463,551	(101,556)	361,995	463,551	(77,402)	386,149
Offshore Pipelines & Services	207,012	(69,369)	137,643	207,012	(54,636)	152,376
Petrochemical Services	56,674	(10,690)	45,984	56,674	(9,194)	47,480
Total	$ 1,247,262	$ (319,061)	$ 928,201	$ 1,255,831	$ (251,876)	$ 1,003,955

(1) During the second quarter of 2007, we adjusted our preliminary purchase price allocation related to the Piceance Creek Acquisition. This adjustment resulted in the reclassification of $8.5 million from intangible assets to property, plant and equipment.

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

	For the Three Months Ended September 30,		**For the Nine Months Ended September 30,**	
	2007	**2006**	**2007**	**2006**
NGL Pipelines & Services	$ 8,869	$ 9,309	$ 26,912	$ 21,974
Onshore Natural Gas Pipelines & Services	7,946	8,375	24,154	25,181
Offshore Pipelines & Services	4,745	5,438	14,733	16,905
Petrochemical Services	499	499	1,495	1,495
Total	$ 22,059	$ 23,621	$ 67,294	$ 65,555

For the remainder of 2007, amortization expense associated with our intangible assets is currently estimated at $22.4 million.

Goodwill

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

	September 30, 2007	**December 31, 2006**
NGL Pipelines & Services	$ 153,698	$ 152,595
Onshore Natural Gas Pipelines & Services	282,121	282,121
Offshore Pipelines & Services	82,135	82,135
Petrochemical Services	73,690	73,690
Totals	$ 591,644	$ 590,541

Note 9. Debt Obligations

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

	September 30, 2007	December 31, 2006
EPO senior debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due October 2011	$ 105,000	$ 410,000
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 E, 4.00% fixed-rate, due October 2007 (1)	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	--
Petal GO Zone Bonds, variable rate, due August 2034	57,500	--
Duncan Energy Partners debt obligation:		
$300 Million Revolving Credit Facility, variable rate, due February 2011	215,000	--
Dixie Revolving Credit Facility, variable rate, due June 2010	10,000	10,000
Other, 8.75% fixed-rate, due June 2010 (2)	5,068	5,068
Total principal amount of senior debt obligations	5,546,568	4,779,068
EPO Junior Subordinated Notes A, due August 2066	550,000	550,000
EPO Junior Subordinated Notes B, due January 2068	700,000	--
Total principal amount of senior and junior debt obligations	6,796,568	5,329,068
Other, including unamortized discounts and premiums and changes in fair value (3)	(24,580)	(33,478)
Long-term debt	$ 6,771,988	$ 5,295,590
Standby letters of credit outstanding	$ --	$ 49,858

(1) In accordance with SFAS 6, Classification of Short-Term Obligations Expected to be Refinanced, long-term and current maturities of debt reflects the classification of such obligations at September 30, 2007 and December 31, 2006. With respect to Senior Notes E, EPO repaid this note on October 15, 2007, using cash and available credit capacity under its $1.25 billion Multi-Year Revolving Credit Facility to fund this repayment.

(2) Represents remaining debt obligations assumed in connection with the GulfTerra Merger, which we expect to redeem in the fourth quarter of 2007.

(3) The September 30, 2007 amount includes a liability of $19.7 million related to fair value hedges and a net $4.9 million in unamortized discounts. The December 31, 2006 amount includes a liability of $29.1 million related to fair value hedges and a net $4.4 million in unamortized discounts.

Parent-Subsidiary guarantor relationships

We act as guarantor of the debt obligations of EPO with the exception of the Dixie revolving credit facility and the senior subordinated notes we assumed in connection with the GulfTerra Merger. If EPO were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. We do not act as guarantor of the debt obligations of Duncan Energy Partners.

EPO s debt obligations

Apart from that discussed below, there have been no significant changes in the terms of EPO s debt obligations since those reported in our annual report on Form 10-K for the year ended December 31, 2006.

Junior Notes B. EPO sold $700 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due January 2068 (Junior Notes B) during the second quarter of 2007. EPO used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. EPO s payment obligations under Junior Notes B are subordinated to all of its current and future senior indebtedness (as defined in the Indenture Agreement). We have guaranteed repayment of amounts due under Junior Notes B through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Notes B allows EPO to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. During any period in which interest payments are deferred and subject to certain exceptions, neither we nor EPO can declare or make any distributions to any of our respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or are subordinate to Junior Notes B. Junior Notes B rank pari passu with the Junior Subordinated Notes A, due August 2066 (Junior Notes A), which were issued during the third quarter of 2006.

The Junior Notes B will bear interest at a fixed annual rate of 7.034% through January 15, 2018, payable semi-annually in arrears in January and July of each year, commencing in January 2008. After January 2018, the Junior Notes B will bear variable rate interest at the greater of (1) the sum of the 3-month London Interbank Offered Rate (LIBOR) for the related interest period plus a spread of 268 basis points or (2) 7.034% per annum, payable quarterly in arrears in January, April, July and October of each year commencing in April 2018. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to certain provisions. The Junior Notes B mature in January 2068 and are not redeemable by EPO prior to January 2018 without payment of a make-whole premium.

In connection with the issuance of Junior Notes B, we and EPO entered into a Replacement Capital Covenant in favor of the covered debt holders (as named therein) pursuant to which we and EPO agreed for the benefit of such debt holders that neither we nor EPO would redeem or repurchase such junior notes on or before January 15, 2038, unless such redemption or repurchase is made from the proceeds of issuance of certain securities.

Senior Notes L. In September 2007, EPO sold $800.0 million in principal amount of ten-year senior unsecured notes (the Senior Notes L) under its new universal shelf registration statement. These notes were issued at 99.953% of their principal amount, have a fixed-rate interest of 6.30% and a maturity date of September 15, 2017. The Senior Notes L will pay interest semi-annually in arrears on March 15 and September 15 of each year, beginning March 15, 2008. EPO used the net proceeds from the issuance of these notes to temporarily reduce indebtedness outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. In October 2007, EPO used borrowing capacity under its Multi-Year Revolving Credit Facility to repay its $500.0 million Senior Notes E.

These fixed-rate notes are unsecured obligations of EPO and rank equally with its existing and future unsecured and unsubordinated indebtedness (as defined in the Indenture Agreement). We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. However, in the future, should any of EPO s subsidiaries become guarantors or co-obligors of its debt obligations maturing in one year or more, then these subsidiaries will jointly and severally, fully and unconditionally, guarantee the payment obligations under the notes. We may redeem the notes before their maturity in whole, at any time, or in part, from time to time, prior to maturity, at a redemption price that includes accrued and unpaid interest and a make-whole premium. These notes were issued under an indenture containing certain covenants, which restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

Petal MBFC Loan. In August 2007, Petal Gas Storage L.L.C. (Petal), a wholly owned subsidiary of EPO, entered into a loan agreement and a promissory note with the Mississippi Business Finance Corporation (MBFC) under which Petal may borrow up to $29.5 million. On the same date, the MBFC issued taxable bonds to EPO in the maximum amount of $29.5 million. As of September 30, 2007, there was $8.9 million outstanding under the loan and the bonds. EPO will make advances on the bonds to the MBFC and the MBFC will in turn make identical advances to Petal under the promissory note. The promissory note and the taxable bonds have identical terms including fixed interest rates of 5.90% and maturities of fifteen years. The bonds and the associated tax incentives are authorized under the Mississippi Business Finance Act. Petal may prepay on the promissory note without penalty, and thus

cause the bonds to be redeemed, any time after one year from their date of issue. The loan and bonds are netted in preparing our consolidated balance sheet, as well the related interest expense and income amounts are netted in preparing our consolidated income statement.

Petal GO Zone Bonds. In August 2007, Petal borrowed $57.5 million from the MBFC pursuant to a loan agreement and promissory note between Petal and the MBFC to pay a portion of the costs of certain natural gas storage facilities located in Petal, Mississippi. The promissory note between Petal and MBFC is guaranteed by EPO and supported by a letter of credit issued under EPO s Multi-Year Revolving Credit Facility. On the same date, the MBFC issued $57.5 million in Gulf Opportunity Zone Tax-Exempt (GO Zone) bonds to various third parties. A portion of the GO Zone bond proceeds are being held by a third party trustee and reflected as a component of other assets on our balance sheet. The remaining proceeds held by the trustee will be released to us as we spend capital to complete the construction of the natural gas storage facilities. At September 30, 2007, $39.3 million of the GO Zone bond proceeds remained held by the third party trustee. The promissory note and the GO Zone bonds have identical terms including floating interest rates and maturities of twenty-seven years. The bonds and the associated tax incentives are authorized under the Mississippi Business Finance Act and the Gulf Opportunity Zone Act of 2005.

Duncan Energy Partners debt obligation

We consolidate the debt of Duncan Energy Partners with that of our own; however, we do not have the obligation to make interest payments or debt payments with respect to the debt of Duncan Energy Partners.

Duncan Energy Partners entered into a $300.0 million revolving credit facility, all of which may be used for letters of credit, with a $30.0 million sublimit for Swingline loans. Letters of credit outstanding under this facility reduce the amount available for borrowings. At the closing of its initial public offering, Duncan Energy Partners made its initial borrowing of $200.0 million under the facility to fund the $198.9 million cash distribution to EPO and the remainder to pay debt issuance costs. At September 30, 2007, the principal balance outstanding under this facility was $215.0 million.

This credit facility matures in February 2011 and will be used by Duncan Energy Partners in the future to fund working capital and other capital requirements and for general partnership purposes. Duncan Energy Partners may make up to two requests for one-year extensions of the maturity date (subject to certain restrictions). The revolving credit facility is available to pay distributions upon the initial contribution of assets to Duncan Energy Partners, fund working capital, make acquisitions and provide payment for general purposes. Duncan Energy Partners can increase the revolving credit facility, without consent of the lenders, by an amount not to exceed $150.0 million by adding to the facility one or more new lenders and/or increasing the commitments of existing lenders. No existing lender is required to increase its commitment, unless it agrees to do so in its sole discretion.

This revolving credit facility offers the following unsecured loans, each having different interest requirements: (i) LIBOR loans bear interest at a rate per annum equal to LIBOR plus the applicable LIBOR margin (as defined in the credit agreement), (ii) Base Rate loans bear interest at a rate per annum equal to the higher of (a) the rate of interest publicly announced by the administrative agent, Wachovia Bank, National Association, as its Base Rate and (b) 0.5% per annum above the Federal Funds Rate in effect on such date and (iii) Swingline loans bear interest at a rate per annum equal to LIBOR plus an applicable LIBOR margin.

The revolving credit facility requires Duncan Energy Partners to maintain a leverage ratio for the prior four fiscal quarters of not more than 4.75 to 1.00 at the last day of each fiscal quarter commencing June 30, 2007; provided that, upon the closing of a permitted acquisition, such ratio shall not exceed (a) 5.25 to 1.00 at the last day of the fiscal quarter in which such specified acquisition occurred and at the last day of each of the two fiscal quarters following the fiscal quarter in which such specified acquisition occurred, and (b) 4.75 to 1.00 at the last day of each fiscal quarter thereafter. In addition, prior to obtaining an investment-grade rating by Standard & Poor s Ratings Services, Moody s Investors Service or Fitch Ratings, Duncan Energy Partners interest coverage ratio, for the prior four fiscal quarters shall not be less

than 2.75 to 1.00 at the last day of each fiscal quarter commencing June 30, 2007.

The Duncan Energy Partners credit facility contains other customary covenants. Also, if an event of default exists under the credit agreement, the lenders will be able to accelerate the maturity date of amounts borrowed under the credit agreement and exercise other rights and remedies.

Canadian Debt Obligations

In May 2007, Canadian Enterprise Gas Products, Ltd. (Canadian Enterprise), a wholly-owned subsidiary of EPO, entered into a $30.0 million Canadian revolving credit facility with The Bank of Nova Scotia. The credit facility, which includes the issuance of letters of credit, matures in October 2011. Letters of credit outstanding under this facility reduce the amount available for borrowings.

Borrowings may be made in Canadian or U.S. dollars. Canadian denominated borrowings may be comprised of Canadian Prime Rate (CPR) loans or Bankers Acceptances and U.S. denominated borrowings may be comprised of Alternative Base Rate (ABR) or Eurodollar loans, each having different interest rate requirements. CPR loans bear interest at a rate determined by reference to the Canadian Prime Rate. ABR loans bear interest at a rate determined by reference to an alternative base rate as defined in the credit agreement. Eurodollar loans bear interest at a rate determined by the LIBOR plus an applicable rate as defined in the credit agreement. Bankers Acceptances carry interest at the rate for Canadian bankers acceptances plus an applicable rate as defined in the credit agreement.

The credit facility contains customary covenants and events of default. The restrictive covenants limit Canadian Enterprise from materially changing the nature of its business or operations, dissolving, or completing mergers. A continuing event of default would accelerate the maturity of amounts borrowed under the credit facility. The obligations under the credit facility are guaranteed by EPO. As of September 30, 2007, there were no debt obligations outstanding under this credit facility.

Covenants

We are in compliance with the covenants of our consolidated debt agreements at September 30, 2007 and December 31, 2006.

Information regarding variable interest rates paid

The following table presents the range of interest rates paid and weighted-average interest rate paid on our consolidated variable-rate debt obligations during the nine months ended September 30, 2007.

	Range of interest rates paid	**Weighted-average interest rate paid**
EPO s Multi-Year Revolving Credit Facility	5.82% to 8.25%	5.87%
Duncan Energy Partners Revolving Credit Facility	5.99% to 6.48%	6.21%

Dixie Revolving Credit Facility	5.66% to 5.67%	5.66%
Canadian Enterprise Revolving Credit Facility	4.95% to 5.82%	5.68%
Petal GO Zone Bonds	3.76% to 4.15%	3.89%

Consolidated debt maturity table

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

2007	$ --
2008	--
2009	500,000
2010	569,068
2011	1,270,000
Thereafter	4,457,500
Total scheduled principal payments	$ 6,796,568

In accordance with SFAS 6, long-term and current maturities of debt reflect the classification of such obligations at September 30, 2007 and December 31, 2006. With respect to the $500.0 million in principal due under Senior Notes E in October 2007, EPO repaid this note on October 15, 2007 using cash and available credit capacity under its Multi-Year Revolving Credit Facility. The preceding table and our Unaudited Condensed Consolidated Balance Sheets at September 30, 2007 and December 31, 2006 reflect this ability to refinance.

Debt Obligations of Unconsolidated Affiliates

We have two unconsolidated affiliates with long-term debt obligations. The following table shows (i) our ownership interest in each entity at September 30, 2007, (ii) total debt of each unconsolidated affiliate at September 30, 2007 (on a 100% basis to the affiliate) and (iii) the corresponding scheduled maturities of such debt.

	Our Ownership Interest	**Total**	**Scheduled Maturities of Debt 2007**	**2008**	**2009**	**2010**	**2011**	**After 2011**
Poseidon	36.0%	$ 91,000	$ --	$ --	$ --	$ --	$ 91,000	$ --
Evangeline	49.5%	25,650	5,000	5,000	5,000	10,650	--	--
Total		$ 116,650	$ 5,000	$ 5,000	$ 5,000	$ 10,650	$ 91,000	$ --

Cameron Highway repaid its $365.0 million Series A notes and $50.0 million Series B notes in May and June 2007, respectively, using cash contributions from its partners. We funded our 50% share of the capital contributions using borrowings under EPO s Multi-Year Revolving Credit Facility. Cameron Highway incurred an $11.0 million make-whole premium in connection with the repayment of its Series A notes.

The credit agreements of our unconsolidated affiliates contain various affirmative and negative covenants, including financial covenants. These businesses were in compliance with such covenants at September 30, 2007. 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.

Apart from the repayment of Cameron Highway s Series A and Series B notes, 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, 2006.

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, Enterprise Products GP.

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 Enterprise Products GP in its sole discretion (subject, under certain circumstances, to the approval of our unitholders).

In April 2007, we filed a registration statement with the SEC 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. A total of 1,518,291 of our common units were issued in February, May and August of 2007 in connection with the DRIP and the employee unit purchase plan (EUPP). The issuance of these units generated $45.3 million in net proceeds.

In August 2007, we filed a universal shelf registration statement with the SEC that allows us to issue an unlimited amount of debt and equity securities.

The following table reflects the number of common units issued and the net proceeds received from underwritten and other common unit offerings completed during the nine months ended September 30, 2007:

	Net Proceeds from Sale of Common Units			
	Number of common units issued	**Contributed by Limited Partners**	**Contributed by General Partner**	**Total Net Proceeds**
February DRIP and EUPP	438,631	$ 12,495	$ 255	$ 12,750
May DRIP and EUPP	494,169	15,181	622	15,803
August DRIP and EUPP	585,491	16,413	333	16,746
Total 2007	1,518,291	$ 44,089	$ 1,210	$ 45,299

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Summary of Changes in Outstanding Units

The following table summarizes changes in our outstanding units since December 31, 2006:

	Common Units	Restricted Common Units
Balance, December 31, 2006	431,303,193	1,105,237
Units issued in connection with DRIP and EUPP	1,518,291	--
Units issued in connection with equity-based awards	241,000	--
Restricted common units issued	--	704,740
Vesting of restricted units	500	(500)
Forfeiture or settlement of restricted units	--	(135,753)
Balance, September 30, 2007	433,062,984	1,673,724

Summary of Changes in Limited Partners Equity

The following table details the changes in limited partners equity since December 31, 2006:

	Common Units	Restricted Common Units	Total
Balance, December 31, 2006	$ 6,320,577	$ 9,340	$ 6,329,917
Net income	286,086	898	286,984
Operating leases paid by EPCO	1,543	5	1,548
Cash distributions to partners	(615,442)	(1,818)	(617,260)
Net proceeds from sales of common units	44,089	--	44,089
Proceeds from exercise of unit options	7,451	--	7,451
Repurchase of restricted units and options	(512)	(1,056)	(1,568)
Unit option reimbursements to EPCO	(2,859)	--	(2,859)
Amortization of equity-based awards	3,095	6,167	9,262
Balance, September 30, 2007	$ 6,044,028	$ 13,536	$ 6,057,564

Distributions to Partners

The percentage interest of Enterprise Products GP 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. Enterprise Products GP 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 $27.4 million and $22.4 million to Enterprise Products GP during the three months ended September 30, 2007 and 2006, respectively. During the nine months ended September 30, 2007 and 2006, we paid incentive distributions of $79.0 million and $62.5 million, respectively, to Enterprise Products GP.

Our quarterly cash distributions for 2007 are presented in the following table:

	Cash Distribution History		
	Distribution per Unit	**Record Date**	**Payment Date**
1st Quarter 2007	$ 0.4750	Apr. 30, 2007	May 10, 2007
2nd Quarter 2007	$ 0.4825	Jul. 31, 2007	Aug. 9, 2007
3rd Quarter 2007	$ 0.4900	Oct. 31, 2007	Nov. 8, 2007

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 change 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 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

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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 the gross operating margin amounts of Duncan Energy Partners on a 100% basis.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Revenues (1)	$ 4,111,996	$ 3,872,525	$ 11,647,656	$ 10,640,452
Less: Operating costs and expenses (1)	(3,896,411)	(3,584,783)	(10,981,562)	(9,955,231)
Add: Equity in income of unconsolidated affiliates (1)	13,960	2,265	13,928	14,306
Depreciation, amortization and accretion in operating costs and expenses (2)	133,869	112,412	374,522	325,180
Operating lease expense paid by EPCO (2)	526	526	1,579	1,582
Loss (gain) on sale of assets in operating costs and expenses (2)	(219)	(3,204)	5,445	(3,401)
Total segment gross operating margin	$ 363,721	$ 399,741	$ 1,061,568	$ 1,022,888

(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, minority interest and the cumulative effect of change in accounting principle follows:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Total segment gross operating margin	$ 363,721	$ 399,741	$ 1,061,568	$ 1,022,888
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(133,869)	(112,412)	(374,522)	(325,180)
Operating lease expense paid by EPCO	(526)	(526)	(1,579)	(1,582)
Gain (loss) on sale of assets in operating costs and expenses	219	3,204	(5,445)	3,401
General and administrative costs	(18,715)	(15,823)	(66,706)	(45,798)
Consolidated operating income	210,830	274,184	613,316	653,729
Other expense, net	(83,369)	(60,657)	(213,327)	(169,705)
Income before provision for income taxes, minority interest				

and cumulative effect of change in accounting principle	$ 127,461	$ 213,527	$ 399,989	$ 484,024

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

	Reportable Segments					
	NGL Pipelines & Services	**Onshore Natural Gas Pipelines & Services**	**Offshore Pipelines & Services**	**Petrochemical Services**	**Adjustments and Eliminations**	**Consolidated Totals**
Revenues from third parties:						
Three months ended September 30, 2007	$ 2,873,937	$ 428,807	$ 54,444	$ 575,969	$ --	$ 3,933,157
Three months ended September 30, 2006	2,797,651	341,537	53,936	547,038	--	3,740,162
Nine months ended September 30, 2007	8,261,659	1,304,239	142,557	1,559,887	--	11,268,342
Nine months ended September 30, 2006	7,689,559	1,062,948	105,794	1,446,279	--	10,304,580
Revenues (losses) from related parties:						
Three months ended September 30, 2007	93,204	86,704	(1,069)	--	--	178,839
Three months ended September 30, 2006	48,699	83,521	143	--	--	132,363
Nine months ended September 30, 2007	169,262	209,807	236	9	--	379,314
Nine months ended September 30, 2006	92,748	242,390	734	--	--	335,872
Intersegment and intrasegment revenues:						
Three months ended September 30, 2007	1,265,697	57,635	484	132,844	(1,456,660)	--
Three months ended September 30, 2006	1,105,719	30,377	484	101,452	(1,238,032)	--
Nine months ended September 30, 2007	3,540,347	119,121	1,531	360,885	(4,021,884)	--
Nine months ended September 30, 2006	3,079,511	90,106	1,187	287,718	(3,458,522)	--
Total revenues:						
Three months ended September 30, 2007	4,232,838	573,146	53,859	708,813	(1,456,660)	4,111,996
Three months ended September 30, 2006	3,952,069	455,435	54,563	648,490	(1,238,032)	3,872,525
Nine months ended September 30, 2007	11,971,268	1,633,167	144,324	1,920,781	(4,021,884)	11,647,656
Nine months ended September 30, 2006	10,861,818	1,395,444	107,715	1,733,997	(3,458,522)	10,640,452
Equity in income (loss) of unconsolidated affiliates:						
Three months ended September 30, 2007	2,684	2,351	8,557	368	--	13,960
Three months ended September 30, 2006	1,422	794	(330)	379	--	2,265
Nine months ended September 30, 2007	4,364	4,592	3,786	1,186	--	13,928
Nine months ended September 30, 2006	4,864	2,300	6,373	769	--	14,306
Gross operating margin by individual business segment and in total:						
Three months ended September 30, 2007	190,209	75,424	46,676	51,412	--	363,721
Three months ended September 30, 2006	232,037	77,489	38,364	51,851	--	399,741
Nine months ended September 30, 2007	589,708	235,102	97,429	139,329	--	1,061,568
Nine months ended September 30, 2006	549,401	260,943	76,131	136,413	--	1,022,888
Segment assets:						
At September 30, 2007	4,037,990	3,683,821	1,450,786	673,448	1,287,350	11,133,395
At December 31, 2006	3,249,486	3,611,974	734,659	502,345	1,734,083	9,832,547
Investments in and advances to unconsolidated affiliates (see Note 7):						
At September 30, 2007	120,294	228,342	488,140	18,049	--	854,825
At December 31, 2006	111,229	124,591	310,136	18,603	--	564,559
Intangible Assets (see Note 8):						
At September 30, 2007	382,579	361,995	137,643	45,984	--	928,201
At December 31, 2006	417,950	386,149	152,376	47,480	--	1,003,955
Goodwill (see Note 8):						
At September 30, 2007	153,698	282,121	82,135	73,690	--	591,644
At December 31, 2006	152,595	282,121	82,135	73,690	--	590,541

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

	For the Three Months Ended September 30, 2007	2006	For the Nine Months Ended September 30, 2007	2006
NGL Pipelines & Services:				
Sale of NGL products	$ 2,837,465	$ 2,640,568	$ 7,952,147	$ 7,276,342
Percent of consolidated revenues	69%	68%	68%	68%
Onshore Natural Gas Pipelines & Services:				
Sale of natural gas	406,482	312,116	1,190,235	943,480
Percent of consolidated revenues	10%	8%	10%	9%
Petrochemical Services:				
Sale of petrochemical products	444,670	417,395	1,268,731	1,157,184
Percent of consolidated revenues	11%	11%	11%	11%

Note 12. Related Party Transactions

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

	For the Three Months Ended September 30, 2007	2006	For the Nine Months Ended September 30, 2007	2006
Revenues from consolidated operations:				
EPCO and affiliates	$ 91,630	$ 47,812	$ 164,299	$ 86,892
Unconsolidated affiliates	87,209	84,551	215,015	248,980
Total	$ 178,839	$ 132,363	$ 379,314	$ 335,872
Operating costs and expenses:				
EPCO and affiliates	$ 74,910	$ 78,570	$ 228,264	$ 244,632
Unconsolidated affiliates	6,414	4,523	22,628	19,113
Total	$ 81,324	$ 83,093	$ 250,892	$ 263,745
General and administrative costs:				
EPCO and affiliates	$ 11,504	$ 10,728	$ 45,292	$ 32,566

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

Relationship with EPCO and affiliates

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

§ EPCO and its private company subsidiaries;

- § Enterprise Products GP, our sole general partner;
- § Enterprise GP Holdings, which owns and controls our general partner;
- § TEPPCO and TEPPCO GP, which are controlled by Enterprise GP Holdings;
- § the Employee Partnerships (see Note 3); and
- § Energy Transfer Equity.

We also have an ongoing relationship with Duncan Energy Partners, the financial statements of which are consolidated with those of our own. Our transactions with Duncan Energy Partners are eliminated in consolidation; therefore, they are not part of the totals presented in the preceding table. A description of our relationship with Duncan Energy Partners is presented within this Note 12.

EPCO is a private company controlled by Dan L. Duncan, who is also a director and Chairman of Enterprise Products GP, our general partner. At September 30, 2007, EPCO and its affiliates beneficially owned 147,870,309 (or 34.0%) of our outstanding common units, which include 13,454,498 of our common units owned by Enterprise GP Holdings. In addition, at September 30, 2007, EPCO and its affiliates beneficially owned 77.1% of the limited partner interests of Enterprise GP Holdings and 100% of its general partner, EPE Holdings. Enterprise GP Holdings owns all of the membership interests of Enterprise Products GP. The principal business activity of Enterprise Products GP is to act as our managing partner. The executive officers and certain of the directors of Enterprise Products GP and EPE Holdings are employees of EPCO.

In connection with its general partner interest in us, Enterprise Products GP received cash distributions of $91.6 million and $73.5 million from us during the nine months ended September 30, 2007 and 2006, respectively. These amounts include incentive distributions of $79.0 million and $62.5 million for the nine months ended September 30, 2007 and 2006, respectively.

We and Enterprise Products GP are both separate legal entities apart from each other and apart from EPCO, Enterprise GP Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Enterprise GP Holdings and their respective other affiliates. EPCO and its private company subsidiaries depend on the cash distributions they receive from us, Enterprise GP Holdings and other investments to fund their other operations and to meet their debt obligations. Enterprise GP Holdings, EPCO and its private company affiliates received $260.7 million and $225.5 million in cash distributions from us during the nine months ended September 30, 2007 and 2006, respectively.

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

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

Historically, we entered into transactions with a Canadian affiliate of EPCO for the purchase and sale of NGL products in the normal course of business. These transactions were at market-related prices. We acquired this affiliate in October 2006 and began consolidating its financial statements with those of our own from the date of acquisition.

EPCO Administrative Services Agreement

We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (the ASA). We and our general partner, Enterprise GP Holdings and its general partner, Duncan Energy Partners and its general partner, and TEPPCO and its general partner, among other affiliates, are parties to the ASA. The ACG Committees of each general partner have approved the ASA.

Under the ASA, we reimburse EPCO for all costs and expenses it incurs in providing management, administrative and operating services to us. The ASA also addresses potential conflicts in business opportunities that may arise among us, Enterprise GP Holdings, Duncan Energy Partners and other affiliates of EPCO.

Relationship with TEPPCO

We received $12.7 million and $14.0 million from TEPPCO during the three months ended September 30, 2007 and 2006, respectively, primarily from the sale of NGLs. We received $42.8 million and $31.1 million from TEPPCO during the nine months ended September 30, 2007 and 2006, respectively, primarily from the sale of NGLs. We paid TEPPCO $4.5 million and $7.1 million for NGL pipeline transportation and storage services during the three months ended September 30, 2007 and 2006, respectively. We paid TEPPCO $13.8 million and $17.7 million for NGL pipeline transportation and storage services during the nine months ended September 30, 2007 and 2006, respectively.

Purchase and lease of pipelines for DEP South Texas NGL Pipeline System from TEPPCO. In January 2007, we purchased a 10-mile segment of pipeline from TEPPCO located in the Houston area for $8.0 million that is part of the DEP South Texas NGL Pipeline System. In addition, we entered into a lease with TEPPCO for an 11-mile interconnecting pipeline located in the Houston area. The primary term of this lease expired in September 2007 and continues on a month-to-month basis subject to termination by either party upon 60 days notice. This pipeline is being leased by a subsidiary of Duncan Energy Partners in connection with operations on its DEP South Texas NGL Pipeline System until construction of a parallel pipeline is completed in the first quarter of 2008.

Jonah Joint Venture with TEPPCO. In August 2006, we formed a joint venture with TEPPCO to be partners in TEPPCO s Jonah Gas Gathering Company, or Jonah. Jonah owns the Jonah Gas Gathering System (the Jonah Gathering System), located in the Greater Green River Basin of southwestern Wyoming. The Jonah Gathering System gathers and transports natural gas produced from the Jonah and Pinedale fields to regional natural gas processing plants and major interstate pipelines that deliver natural gas to end-user markets.

Prior to entering into the Jonah joint venture, we managed the construction of the Phase V expansion and funded the initial construction costs under a letter of intent we signed in February 2006. In connection with the joint venture arrangement, we and TEPPCO will continue the Phase V expansion, which is expected to increase the capacity of the Jonah Gathering System from 1.5 Bcf/d to 2.3 Bcf/d. The Phase V expansion is also expected to significantly reduce system operating pressures, which we anticipate will lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which is expected to increase the system gathering capacity to 2.0 Bcf/d, was completed in July 2007. The second portion of the expansion is expected to be completed by the first quarter of 2008. We will operate the Jonah Gathering System.

We manage the Phase V construction project. TEPPCO is entitled to all distributions from the joint venture until specified milestones are achieved, at which point, we will be entitled to receive 50% of the incremental cash flow from portions of the system placed in service as part of the expansion. After subsequent milestones are achieved, we and TEPPCO will share distributions based on a formula that takes into account the respective capital contributions of the parties, including expenditures by TEPPCO prior to the expansion.

Since August 1, 2006, we and TEPPCO equally share in the construction costs of the Phase V expansion. TEPPCO has reimbursed us $208.8 million for its share of the Phase V costs. At September 30, 2007, we had a receivable from TEPPCO of $13.0 million for additional Phase V costs incurred through September 30, 2007.

Upon completion of the expansion project and based on the formula in the joint venture partnership agreement, we expect to own an interest in Jonah of approximately 20%, with TEPPCO owning the remaining 80%. Phase I of this expansion project was completed in July 2007, thus at September 30, 2007, we and TEPPCO owned and shared earnings of approximately 19.4% interest and 80.6% interest, respectively, in Jonah.

The joint venture is governed by a management committee comprised of two representatives approved by us and two representatives appointed by TEPPCO, each with equal voting power. After an in-depth consideration of all relevant factors, this transaction was approved by the Audit, Conflicts and Governance Committee of our general partner and that of TEPPCO GP.

Relationship with Energy Transfer Equity

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

For the three and five months ended September 30, 2007, we recorded $79.0 million and $121.5 million of revenues from Energy Transfer Partners, L.P. (ETP), primarily from NGL marketing activities. We incurred $2.6 million and $8.4 million in operating costs and expenses for the three and five months ended September 30, 2007. We have a long-term revenue generating contract with Titan Energy Partners, L.P. (Titan), a consolidated subsidiary of ETP. Titan purchases substantially all of its propane requirements from us. The contract continues until March 31, 2010 and contains renewal and extension options. We and Energy Transfer Company (ETC OLP) transport natural gas on each other s systems and share operating expenses on certain pipelines. ETC OLP also sells natural gas to us.

Relationship with Duncan Energy Partners

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. All intercompany transactions between us and Duncan Energy Partners are eliminated in the preparation of our consolidated financial statements. 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.

On February 5, 2007, Duncan Energy Partners completed its initial public offering of 14,950,000 common units (including an overallotment amount of 1,950,000 common units) at $21.00 per unit, which generated net proceeds to Duncan Energy Partners of $291.9 million. As consideration for assets contributed and reimbursement for capital expenditures related to these assets, Duncan Energy Partners distributed $260.6 million of these net proceeds to us along with $198.9 million in borrowings under its credit facility and a final amount of 5,351,571 common units of Duncan Energy Partners. Duncan Energy Partners used $38.5 million of net proceeds from the overallotment to redeem 1,950,000 of the 7,301,571 common units it had originally issued to Enterprise Products Partners, resulting in the final amount of 5,351,571 common units beneficially owned by Enterprise Products Partners. We used the cash received from Duncan Energy Partners to temporarily reduce amounts outstanding under EPO s Multi-Year Revolving Credit Facility.

We contributed 66% of our equity interests in the following subsidiaries to Duncan Energy Partners:

§ Mont Belvieu Caverns, LLC (Mont Belvieu Caverns), which owns salt dome storage caverns located in Mont Belvieu, Texas that receive, store and deliver NGLs and certain petrochemical products for industrial customers located along the upper Texas Gulf Coast, which has the largest concentration of petrochemical plants and refineries in the United States;

§ Acadian Gas, LLC (Acadian Gas), which owns an onshore natural gas pipeline system that gathers, transports, stores and markets natural gas in Louisiana. The Acadian Gas system links natural gas supplies from onshore and offshore Gulf of Mexico developments (including offshore pipelines, continental shelf and deepwater production) with local gas distribution companies, electric generation plants and industrial customers, including those in the Baton Rouge-New Orleans-Mississippi River corridor. A subsidiary of Acadian Gas owns our 49.5% equity interest in Evangeline;

§ Sabine Propylene Pipeline L.P. (Sabine Propylene), which transports polymer-grade propylene between Port Arthur, Texas and a pipeline interconnect located in Cameron Parish, Louisiana;

§ Enterprise Lou-Tex Propylene Pipeline L.P. (Lou-Tex Propylene), which transports chemical-grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas; and

§ South Texas NGL Pipelines, LLC (South Texas NGL), which began transporting NGLs from Corpus Christi, Texas to Mont Belvieu, Texas in January 2007. South Texas NGL owns the DEP South Texas NGL Pipeline System.

In addition to the 34% direct ownership interest we retained in such entities, we also own the 2% general partner interest in Duncan Energy Partners and 26.4% of Duncan Energy Partners outstanding common units at September 30, 2007. Accordingly, we have in effect retained a net economic interest of approximately 52.7% in Duncan Energy Partners as of September 30, 2007. EPO directs the business operations of Duncan Energy Partners indirectly through its ownership and control of the general partner of Duncan Energy Partners.

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

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

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

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

We may contribute or sell other equity interests in our subsidiaries to Duncan Energy Partners and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program. We have no obligation or commitment to make such contributions or sales to Duncan Energy Partners.

In September 2007, Enterprise Texas Pipeline LLC, a wholly owned subsidiary of EPO, purchased certain parcels of land and regulatory permits from Mont Belvieu Caverns for $3.2 million. Due to common control considerations, the approximate $3.2 million excess of the proceeds received from EPO over the carrying value of assets sold was recorded as a general contribution by Mont Belvieu Caverns.

Relationships with Unconsolidated Affiliates

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

See Relationship with TEPPCO within this Note 12 for a description of ongoing transactions involving our Jonah joint venture with TEPPCO.

Note 13. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the weighted-average number of distribution-bearing units outstanding during a period. Diluted earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the sum of (i) the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit); (ii) the weighted-average number of performance-based phantom units outstanding during a period; and (iii) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the incremental option units).

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

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

	For the Three Months Ended September 30,		**For the Nine Months Ended September 30,**	
	2007	**2006**	**2007**	**2006**
Net income	$ 117,606	$ 208,302	$ 371,805	$ 468,374
Less incentive earnings allocations to Enterprise Products GP	(27,394)	(22,386)	(78,964)	(62,497)
Net income available after incentive earnings allocation	90,212	185,916	292,841	405,877
Multiplied by Enterprise Products GP ownership interest	2.0%	2.0%	2.0%	2.0%
Standard earnings allocation to Enterprise Products GP	$ 1,804	$ 3,718	$ 5,857	$ 8,118
Incentive earnings allocation to Enterprise Products GP	$ 27,394	$ 22,386	$ 78,964	$ 62,497
Standard earnings allocation to Enterprise Products GP	1,804	3,718	5,857	8,118
Enterprise Products GP interest in net income	$ 29,198	$ 26,104	$ 84,821	$ 70,615

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2007	2006	2007	2006
Income before change in accounting principle and Enterprise Products GP interest	$ 117,606	$ 208,302	$ 371,805	$ 466,899
Cumulative effect of change in accounting principle	--	--	--	1,475
Net income	117,606	208,302	371,805	468,374
Enterprise Products GP interest in net income	(29,198)	(26,104)	(84,821)	(70,615)
Net income available to limited partners	$ 88,408	$ 182,198	$ 286,984	$ 397,759
BASIC EARNINGS PER UNIT				
Numerator				
Income before change in accounting principle and Enterprise Products GP interest	$ 117,606	$ 208,302	$ 371,805	$ 466,899
Cumulative effect of change in accounting principle	--	--	--	1,475
Enterprise Products GP interest in net income	(29,198)	(26,104)	(84,821)	(70,615)
Limited partners interest in net income	$ 88,408	$ 182,198	$ 286,984	$ 397,759
Denominator				
Common units	432,805	418,790	432,221	407,539
Time-vested restricted units	1,645	1,064	1,364	930
Total	434,450	419,854	433,585	408,469
Basic earnings per unit				
Income before change in accounting principle and Enterprise Products GP interest	$ 0.27	$ 0.50	$ 0.86	$ 1.14
Cumulative effect of change in accounting principle	--	--	--	0.00
Enterprise Products GP interest in net income	(0.07)	(0.07)	(0.20)	(0.17)
Limited partners interest in net income	$ 0.20	$ 0.43	$ 0.66	$ 0.97
DILUTED EARNINGS PER UNIT				
Numerator				
Income before change in accounting principle and Enterprise Products GP interest	$ 117,606	$ 208,302	$ 371,805	$ 466,899
Cumulative effect of change in accounting principle	--	--	--	1,475
Enterprise Products GP interest in net income	(29,198)	(26,104)	(84,821)	(70,615)
Limited partners interest in net income	$ 88,408	$ 182,198	$ 286,984	$ 397,759
Denominator				
Common units	432,805	418,790	432,221	407,539
Time-vested restricted units	1,645	1,064	1,364	930
Performance-based restricted units	9	16	9	23
Incremental option units	354	332	480	271
Total	434,813	420,202	434,074	408,763
Diluted earnings per unit				
Income before change in accounting principle and Enterprise Products GP interest	$ 0.27	$ 0.50	$ 0.86	$ 1.14
Cumulative effect of change in accounting principle	--	--	--	0.00
Enterprise Products GP interest in net income	(0.07)	(0.07)	(0.20)	(0.17)
Limited partners interest in net income	$ 0.20	$ 0.43	$ 0.66	$ 0.97

Note 14. Commitments and Contingencies

Litigation

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

litigation, pending or threatened, that could have a significant adverse effect on our financial position, cash flows or results of operations.

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

The amended complaint alleges, among other things, that the defendants have caused TEPPCO to enter into certain transactions with us or our affiliates that were unfair to TEPPCO or otherwise unfairly favored us or our affiliates over TEPPCO. These transactions are alleged to include the joint venture to further expand the Jonah Gathering System entered into by TEPPCO and one of our affiliates in August 2006 and the sale by TEPPCO to one of our affiliates of the Pioneer gas processing plant in March 2006. The amended complaint seeks (i) rescission of these transactions or an award of rescissory damages with respect thereto; (ii) damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the amended complaint; and (iii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts. We believe this lawsuit is without merit and intend to vigorously defend against it. See Note 12 for additional information regarding our relationship with TEPPCO.

On February 13, 2007, EPO received notice from the U.S. Department of Justice (DOJ) that it was the subject of a criminal investigation related to an ammonia release in Kingman County, Kansas on October 27, 2004 from a pressurized anhydrous ammonia pipeline owned by a third party, Magellan Ammonia Pipeline, L.P. (Magellan). EPO is the operator of this pipeline. On February 14, 2007, EPO received a letter from the Environment and Natural Resources Division (ENRD) of the DOJ regarding this incident and a previous release of ammonia on September 27, 2004 from the same pipeline. The ENRD has indicated that it may pursue civil damages against EPO and Magellan as a result of these incidents. Based on this correspondence from the ENRD, the statutory maximum amount of civil fines that could be assessed against EPO and Magellan is up to $17.4 million in the aggregate. EPO is cooperating with the DOJ and is hopeful that an expeditious resolution of this civil matter acceptable to all parties will be reached in the near future. Magellan has agreed to indemnify EPO for the civil matter. On September 4, 2007, we and the DOJ entered into a plea agreement whereby a wholly-owned subsidiary of EPO, Mapletree, LLC, pleaded guilty to a misdemeanor charge of negligence in connection with the releases and paid a fine of $1.0 million. The plea agreement concludes the DOJ's criminal investigation into the ammonia releases. At this time, we do not believe that a final resolution of the civil claims by the ENRD will have a material impact on our consolidated financial position, cash flows or results of operations.

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

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

Operating Leases

We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Our significant lease agreements involve (i) the lease of underground caverns for the storage of

natural gas and NGLs, (ii) leased office space with an affiliate of EPCO, and (iii) land held pursuant to right-of-way agreements. In general, our material lease agreements have original terms that range from 14 to 20 years and include renewal options that could extend the agreements for up to an additional 20 years. Lease expense is charged to operating costs and expenses on a straight line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred.

There have been no material changes in our operating lease commitments since December 31, 2006, except for the commitments associated with a new natural gas storage lease. In order to provide firm natural gas transportation and storage services under long-term agreements with CenterPoint Energy Resources Corp. (CenterPoint Energy) in Houston, Texas, we entered into a 2-year agreement during the second quarter of 2007 for firm natural gas storage capacity in Texas. Our rental payments under the lease are at a fixed rate. Contingent rental payments are based upon the actual volume of natural gas we inject or withdraw from the storage cavern over the term of the lease agreement. The incremental future minimum lease payments associated with our new natural gas storage lease are \$3.7 million in 2007, \$4.9 million in 2008 and \$1.2 million in 2009. CenterPoint Energy will reimburse us for the costs we incur associated with this natural gas storage lease.

Lease and rental expense included in operating costs and expenses was \$9.1 million and \$10.3 million during the three months ended September 30, 2007 and 2006, respectively. For the nine months ended September 30, 2007 and 2006, lease and rental expense included in operating costs and expenses was \$28.9 million and \$30.0 million, respectively.

Contractual Obligations

With the exception of the debt incurred by Duncan Energy Partners in connection with its initial public offering and the issuance of Junior Notes B and Senior Notes L by EPO, there have been no significant changes in our consolidated scheduled maturities of long-term debt since those reported in our annual report on Form 10-K for the year ended December 31, 2006. See Note 9 for additional information regarding the debt obligations of Duncan Energy Partners and the issuance of Junior Notes B and Senior Notes L.

Performance Guaranty

In December 2004, a subsidiary of ours entered into the Independence Hub Agreement with six oil and natural gas producers. We guaranteed to the producers the construction-related performance of our subsidiary up to an amount of \$340.8 million. The performance guaranty expired during the second quarter of 2007.

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally make claims against such parties or have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of September 30, 2007, our contingent asserted claims against such parties were approximately \$2.2 million and asserted claims against us for various periods were approximately \$35.5 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated. Such asserted claim amounts may increase or decrease depending on the ultimate resolution of these matters. However, in our opinion, the likelihood of a material adverse outcome related to disputes against us is remote. Accordingly, accruals for loss contingencies related to these matters, if any, that might result from the resolution of such disputes have not been reflected in our consolidated financial statements.

Note 15. Significant Risks and Uncertainties Weather-Related Risks

The following is a discussion of the general status of our insurance claims related to recent significant storm events. To the extent we include any estimate or range of estimates regarding the dollar value of damages, please be aware that a change in our estimates may occur as additional information becomes available. To the extent we receive nonrefundable cash proceeds from business interruption insurance claims, they are recorded as revenue in our Unaudited Condensed Statements of Consolidated Operations in the period of receipt.

Hurricane Ivan insurance claims. We have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan, which struck the eastern U.S. Gulf Coast region in September 2004. We are continuing our efforts to collect residual balances and expect to complete the process during 2007.

Hurricanes Katrina and Rita insurance claims. Hurricanes Katrina and Rita, both significant storms, affected certain of our Gulf Coast assets in August and September of 2005, respectively. We continue to pursue collection of our property damage and business interruption claims related to Hurricanes Katrina and Rita.

The following table summarizes the proceeds we received for the three and nine months ended September 30, 2007 and 2006 from business interruption and property damage insurance claims with respect to certain named storms:

	For the Three Months Ended September 30,		**For the Nine Months Ended September 30,**	
	2007	**2006**	**2007**	**2006**
Business interruption proceeds:				
Hurricane Ivan	$ --	$ 5,157	$ 377	$ 17,383
Hurricane Katrina	1,301	24,325	14,500	24,325
Hurricane Rita	743	20,740	9,000	20,740
Other	--	--	996	--
Total proceeds	2,044	50,222	24,873	62,448
Property damage proceeds:				
Hurricane Ivan	--	--	1,273	24,104
Hurricane Katrina	--	6,975	6,563	6,975
Hurricane Rita	--	2,730	--	2,730
Other	--	--	184	--
Total proceeds	--	9,705	8,020	33,809
Total	$ 2,044	$ 59,927	$ 32,893	$ 96,257

Note 16. Supplemental Cash Flow Information

Our Unaudited Condensed Statements of Consolidated Cash Flows are prepared using the indirect method. The indirect method derives net cash flows from operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and similar transactions, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, (iii) the effects of all items classified as investing or financing cash flows, such as gains or losses on sale of property, plant and equipment or extinguishment of debt, and (iv) other non-cash amounts such as depreciation, amortization and changes in the fair market value of financial instruments.

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

	For the Nine Months Ended September 30, 2007	2006
Decrease (increase) in:		
Accounts and notes receivable	$ (281,949)	$ 72,878
Inventories	(170,610)	(122,672)
Prepaid and other current assets	(41,171)	(42,597)
Other assets	4,719	(3,229)
Increase (decrease) in:		
Accounts payable	61,106	21,799
Accrued product payables	354,508	63,667
Accrued expenses	152,534	63,500
Accrued interest	10,020	9,334
Other current liabilities	26,110	100,858
Other long-term liabilities	(4,995)	(3,689)
Net effect of changes in operating accounts	$ 110,272	$ 159,849

Contributions in aid of construction costs

Third parties may be obligated to reimburse us for all or a portion of expenditures on certain of our capital projects. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. We received $52.5 million and $63.7 million as contributions in aid of our construction costs during the nine months ended September 30, 2007 and 2006, respectively.

Cash used for business combinations Encinal Acquisition in July 2006

In July 2006, we acquired the Encinal and Canales natural gas gathering systems and related gathering and processing contracts that comprised the South Texas natural gas transportation and processing business of an affiliate of Lewis Energy Group, L.P. (Lewis). The aggregate value of total consideration we paid or issued to complete this business combination (referred to as the Encinal acquisition) was $326.3 million, which consisted of $145.2 million in cash and 7,115,844 of our common units.

The Encinal and Canales gathering systems are located in South Texas and are connected to over 1,450 natural gas wells producing from the Olmos and Wilcox formations. The Encinal system consists of 452 miles of pipeline, which consists of 280 miles of pipeline we acquired from Lewis in this transaction and 172 miles of pipeline that we own and had previously leased to Lewis. The Canales gathering system is comprised of 32 miles of pipeline. Currently, natural gas volumes gathered by the Encinal and Canales systems are transported by our existing Texas Intrastate System and are processed by our South Texas natural gas processing plants.

Note 17. Condensed Financial Information of EPO

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

We guarantee the consolidated debt obligations of EPO with the exception of the Dixie revolving credit facility, Duncan Energy Partners credit facility and the senior subordinated notes assumed in connection with the GulfTerra Merger. If EPO were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. See Note 9 for additional information regarding our consolidated debt obligations.

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

	September 30, 2007	December 31, 2006
ASSETS		
Current assets	$ 2,418,232	$ 1,915,937
Property, plant and equipment, net	11,133,395	9,832,547
Investments in and advances to unconsolidated affiliates, net	854,825	564,559
Intangible assets, net	928,201	1,003,955
Goodwill	591,644	590,541
Deferred tax asset	2,073	1,632
Other assets	80,358	74,103
Total	$ 16,008,728	$ 13,983,274
LIABILITIES AND PARTNERS EQUITY		
Current liabilities	$ 2,479,205	$ 1,986,444
Long-term debt	6,771,988	5,295,590
Other long-term liabilities	102,354	99,845
Minority interest	437,519	136,249
Partners equity	6,217,662	6,465,146
Total	$ 16,008,728	$ 13,983,274
Total EPO debt obligations guaranteed by us	$ 6,566,500	$ 5,314,000

The following table presents condensed consolidated statements of operations data for EPO for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Revenues	$ 4,111,996	$ 3,872,525	$ 11,647,656	$ 10,640,452
Costs and expenses	3,917,172	3,599,990	11,046,151	9,997,962
Equity in income of unconsolidated affiliates	13,960	2,265	13,928	14,306
Operating income	208,784	274,800	615,433	656,796
Other expense	(84,001)	(61,209)	(215,088)	(171,134)
Income before provision for income taxes, minority interest and change in accounting principle	124,783	213,591	400,345	485,662
Provision for income taxes	(2,072)	(3,214)	(9,006)	(12,378)
Income before minority interest and change in accounting principle	122,711	210,377	391,339	473,284
Minority interest	(7,804)	(2,028)	(19,325)	(4,761)
Income before change in accounting principle	114,907	208,349	372,014	468,523
Cumulative effect of change in accounting principle	--	--	--	1,475
Net income	$ 114,907	$ 208,349	$ 372,014	$ 469,998

Note 18. Subsequent Event

On November 1, 2007, Dixie experienced a rupture on its mainline near Carmichael, Mississippi. The incident resulted in two fatalities and an undetermined number of injuries. The cause of the incident is unknown; however, an investigation is underway by the Company and all appropriate governmental agencies. The affected portion of the pipeline will not return to service until we and all appropriate governmental authorities have determined that it is safe to do so. We currently expect operations to resume in the fourth quarter of 2007.

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

For the three and nine months ended September 30, 2007 and 2006.

The following information should be read in conjunction with our Unaudited Condensed Consolidated Financial Statements and our accompanying notes included under Item 1 of this quarterly report on Form 10-Q and with the information contained within our annual report on Form 10-K for the year ended December 31, 2006. Our discussion and analysis includes the following:

§ Cautionary Note Regarding Forward-Looking Statements.

§ Overview of Critical Accounting Policies and Estimates.

§ Overview of Business.

§ Recent Developments Discusses significant developments since December 31, 2006.

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

§ Liquidity and Capital Resources Addresses available sources of liquidity and analyzes cash flows, including capital spending.

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

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

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

Our financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP).

Unless the context requires otherwise, references to we, us, our or Enterprise Products Partners are intended to mean the business and operation of Enterprise Products Partners L.P. and its consolidated subsidiaries, including Duncan Energy Partners L.P. (Duncan Energy Partners).

In addition, references to TEPPCO mean TEPPCO Partners, L.P., a publicly traded Delaware limited partnership, which is an affiliate of us. References to TEPPCO GP refer to Texas Eastern Products Pipeline Company LLC, which is the general partner of TEPPCO and wholly owned by Enterprise GP Holdings L.P. (Enterprise GP Holdings).

References to Energy Transfer Equity mean Energy Transfer Equity, L.P. and its consolidated affiliates, including Energy Transfer Partners, L.P. References to ETEGP mean LE GP, LLC, which is the general partner of Energy Transfer Equity. Enterprise GP Holdings acquired equity interests in Energy Transfer Equity and ETEGP in May 2007.

Cautionary Note Regarding Forward-Looking Statements

This discussion contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as anticipate, project, expect, plan, goal, forecast, intend, could, believe, may and similar expressions and statements regarding our plans and objectives f operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A, Risk Factors, included in our annual report on Form 10-K for 2006. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements.

Overview of Critical Accounting Policies and Estimates

A summary of the significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is included in our Annual Report on Form 10-K for the year ended December 31, 2006. Certain of these accounting policies require the use of estimates. As more fully described therein, the following estimates, in our opinion, are subjective in nature, require the exercise of judgment and involve complex analysis: depreciation methods and estimated useful lives of property, plant and equipment; measuring recoverability of long-lived assets and equity method investments; amortization methods and estimated useful lives of qualifying intangible assets; methods we employ to measure the fair value of goodwill; our revenue recognition policies and use of estimates for revenues and expenses; reserves for environmental matters; and natural gas imbalances. These estimates are based on our knowledge and understanding of current conditions and actions we may take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our financial position, results of operations and cash flows.

Overview of Business

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

Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. We have four reportable business segments: NGL Pipelines & Services; Onshore Natural Gas Pipelines & Services; Offshore Pipelines & Services; and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We conduct substantially all of our business through Enterprise Products Operating LLC (EPO), as successor in interest by merger to Enterprise Products Operating L.P. We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our general partner, referred to as Enterprise Products GP). Enterprise Products GP is owned 100% by Enterprise GP Holdings, a publicly traded affiliate listed on the NYSE under the ticker symbol EPE. We, Enterprise Products GP and Enterprise GP Holdings are affiliates under the common control of Dan L. Duncan, the Chairman and controlling shareholder of EPCO, Inc. (EPCO).

We are committed to the long-term growth and viability of Enterprise Products Partners. Part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. We believe we are positioned to continue to grow our system of assets through the construction of new facilities and to capitalize on expected future production increases from such areas as the Piceance Basin of western Colorado, the Greater Green River Basin in Wyoming, the Barnett Shale in North Texas, and the deepwater Gulf of Mexico. Management continues to analyze potential acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In recent years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We expect this trend to continue, and expect independent oil and natural gas companies to consider similar divestitures. For information regarding our capital spending, see the discussion of our investing cash flows under Liquidity and Capital Resources within this Item 2.

Recent Developments

The following information highlights our significant developments since January 1, 2007 through the date of this filing.

§ In October 2007, we commenced natural gas processing operations at our Meeker facility, which recently completed its first phase of construction. Located in Colorado s Piceance Basin, our Meeker facility has a processing capacity of 750 MMcf/d of natural gas and is capable of extracting up to 35 MBPD of mixed NGLs. Phase II of the Meeker facility, which is under construction and expected to be completed in the third quarter of 2008, will double its processing capacity to 1.5 Bcf/d of natural gas and 70 MBPD of mixed NGLs. The two phases are supported by long-term commitments from producers, including EnCana and ExxonMobil. Natural gas volumes are expected to exceed 500 MMcf/d by the end of 2007, which are expected to produce more than 27.7 MBPD of mixed NGLs. The Piceance Basin represents one of the most prolific and fastest growing energy producing areas in the nation, and the completion of our Meeker facility provides the region with valuable midstream infrastructure needed to accommodate those growing volumes.

§ In October 2007, we completed the expansion of the Rocky Mountain portion of our Mid-America Pipeline (MAPL) system. The final phase of this project consisted of installing new pumps and the modification of existing pumps, which increased system capacity by 20 MBPD. The first phase, which was completed in April 2007, provided an additional 30 MBPD of system capacity. Overall, these expansion projects increased the capacity of MAPL s Rocky Mountain system from 225 MBPD to 275 MBPD. This expansion will accommodate expected mixed NGL volumes originating from our Meeker facility.

§ In September 2007, EPO sold $800.0 million in principal amount of 6.30% fixed-rate, unsecured senior notes due September 2017. Net proceeds from this offering were used to temporarily reduce borrowings outstanding under EPO s Multi-Year Revolving Credit Facility. In October 2007, EPO used borrowing capacity under its revolver to repay $500.0 million in principal amount due under its Senior Notes E. See Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements for information regarding our debt obligations.

§ In August 2007, we entered into a memorandum of understanding with Questar Pipeline Company (Questar) to develop a new natural gas pipeline hub in the Rockies. As proposed, the White River Hub would be a header system that will be owned equally by us and Questar. The facilities would connect our natural gas processing complex near Meeker, Colorado, with up to six interstate pipelines in the Piceance Basin area, including the Questar Pipeline.

§ In August 2007, we completed the expansion of our petrochemical assets in Mont Belvieu and southeast Texas. This expansion project included (i) the construction of a fourth propylene fractionator at our Mont Belvieu complex, which increased our propylene/propane

fractionation capacity by approximately one billion pounds per year, or 15 MBPD, and (ii) the expansion of two refinery grade propylene gathering pipelines which added 50 MBPD of gathering capacity into Mont Belvieu.

§ In August 2007, we completed construction of our Hobbs NGL fractionator, which is designed to handle up to 75 MBPD of mixed NGLs. The new fractionator is strategically located at the interconnection of our MAPL and our Seminole pipelines near Hobbs, New Mexico. Our Hobbs NGL fractionator offers another key hub for separating mixed NGLs produced at our Meeker facility into purity NGL products.

§ In July 2007, our Independence Hub platform and Independence Trail pipeline received first production from deepwater production wells connected to the Independence Hub platform. As a result, these assets began earning fee-based revenues for natural gas processing and transportation services. These amounts are in addition to the demand fee revenues that Independence Hub began earning in March 2007. Currently, the platform is receiving approximately 900 MMcf/d of natural gas from fourteen wells. We expect that the platform will approach its full capacity of 1 Bcf/d by the end of 2007.

§ In July 2007, we announced changes to our senior management team that became effective August 1, 2007. The board of directors of our general partner elected Michael A. Creel president and chief executive officer, W. Randall Fowler executive vice president and chief financial officer, and William Ordemann executive vice president and chief operating officer. Mr. Creel replaces Robert G. Phillips who resigned effective June 30, 2007. Mr. Fowler was promoted to fill the position left vacant by Mr. Creel s promotion. Mr. Ordemann was promoted to fill the position vacated by Dr. Ralph S. Cunningham, who is now the president and chief executive officer of Enterprise GP Holdings. Mr. Creel had previously held this position.

§ In July 2007, we completed the first portion of the Phase V Expansion of the Jonah Gathering System, which increased the system gathering capacity to 2.0 Bcf/d. The second and final phase of the expansion, which is targeted for completion in the first quarter of 2008, is expected to increase the system s gathering capacity further to 2.3 Bcf/d.

§ In June 2007, we announced the completion of our project to expand the capabilities of our import/export terminal at the Houston Ship Channel to handle incremental volumes of natural gas liquids and liquefied petroleum gases.

§ In May 2007, EPO sold $700 million in principal amount of fixed/floating unsecured junior subordinated notes due January 2068. Net proceeds from this offering were used by EPO to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes.

§ In March 2007, we formed a natural gas services and marketing business similar to our existing NGL and petrochemical marketing businesses. This new group will be the focal point for all of our existing natural gas supply and marketing activities, which currently include producer wellhead services, facility fuel procurement, pipeline and storage capacity optimization, and a full range of market customer delivery arrangements. This initiative is expected to broaden our role in the natural gas markets by linking our extensive U.S. natural gas pipeline and storage assets, thus providing customers with value-added solutions and reducing our operating costs through enhanced fuel procurement practices.

§ In February 2007, a consolidated subsidiary of ours, Duncan Energy Partners, completed its underwritten initial public offering of 14,950,000 common units. Duncan Energy Partners, a Delaware limited partnership, was formed to acquire ownership interests in certain of our midstream energy businesses. For additional information regarding Duncan Energy Partners, see Other Items Initial Public Offering of Duncan Energy Partners included within this Item 2.

Results of Operations

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

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

We define total segment gross operating margin as consolidated operating income before (i) depreciation, amortization and accretion expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses 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 change in accounting principle. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intersegment and intrasegment transactions. Intercompany accounts and transactions are eliminated in consolidation.

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

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

For additional information regarding our business segments, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Selected Price and Volumetric Data

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

	Natural Gas, $/MMBtu (1)	Crude Oil, $/barrel (2)	Ethane, $/gallon (1)	Propane, $/gallon (1)	Normal Butane, $/gallon (1)	Isobutane, $/gallon (1)	Natural Gasoline, $/gallon (1)	Polymer Grade Propylene, $/pound (1)	Refinery Grade Propylene, $/pound (1)
2006									
1st Quarter	$9.01	$63.35	$0.57	$0.94	$1.20	$1.27	$1.38	$0.45	$0.40
2nd Quarter	$6.80	$70.53	$0.68	$1.05	$1.22	$1.26	$1.52	$0.50	$0.44
3rd Quarter	$6.58	$70.44	$0.76	$1.10	$1.28	$1.30	$1.53	$0.51	$0.46
4th Quarter	$6.56	$60.03	$0.62	$0.95	$1.11	$1.12	$1.31	$0.44	$0.35
2006 Averages	$7.24	$66.09	$0.66	$1.01	$1.20	$1.24	$1.44	$0.47	$0.41
2007									
1st Quarter	$6.77	$58.02	$0.59	$0.97	$1.13	$1.22	$1.37	$0.45	$0.40
2nd Quarter	$7.55	$64.97	$0.72	$1.13	$1.33	$1.45	$1.65	$0.51	$0.46
3rd Quarter	$6.16	$75.48	$0.82	$1.23	$1.44	$1.49	$1.68	$0.52	$0.46
2007 Averages	$6.83	$66.15	$0.71	$1.11	$1.30	$1.38	$1.57	$0.49	$0.44

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

(2) Crude oil price is representative of an index price for West Texas Intermediate.

The following table presents our significant average throughput, production and processing volumetric data. These statistics are reported on a net basis, taking into account our ownership interests in certain joint ventures, and reflect the periods in which we owned an interest in such operations.

	For the Three Months Ended September 30, 2007	2006	For the Nine Months Ended September 30, 2007	2006
NGL Pipelines & Services, net:				
NGL transportation volumes (MBPD)	1,575	1,706	1,626	1,579
NGL fractionation volumes (MBPD)	371	341	379	302
Equity NGL production (MBPD)	64	67	67	63
Fee-based natural gas processing (MMcf/d)	2,269	2,237	2,358	2,224
Onshore Natural Gas Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	6,597	6,049	6,576	6,066
Offshore Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	1,271	1,573	1,322	1,524
Crude oil transportation volumes (MBPD)	163	173	164	149
Platform gas processing (MMcf/d)	286	160	295	158
Platform oil processing (MBPD)	24	12	24	12
Petrochemical Services, net:				
Butane isomerization volumes (MBPD)	96	82	93	83
Propylene fractionation volumes (MBPD)	59	57	58	55
Octane additive production volumes (MBPD)	11	11	9	8
Petrochemical transportation volumes (MBPD)	108	101	104	94
Total, net:				
NGL, crude oil and petrochemical transportation volumes (MBPD)	1,846	1,980	1,894	1,822
Natural gas transportation volumes (BBtus/d)	7,868	7,622	7,898	7,590
Equivalent transportation volumes (MBPD) (1)	3,917	3,986	3,972	3,819

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

Comparison of Results of Operations

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Revenues	$ 4,111,996	$ 3,872,525	$ 11,647,656	$ 10,640,452
Operating costs and expenses	3,896,411	3,584,783	10,981,562	9,955,231
General and administrative costs	18,715	15,823	66,706	45,798
Equity in income of unconsolidated affiliates	13,960	2,265	13,928	14,306
Operating income	210,830	274,184	613,316	653,729
Interest expense	85,075	62,793	219,708	177,203
Net income	117,606	208,302	371,805	468,374

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Gross operating margin by segment:				
NGL Pipelines & Services	$ 190,209	$ 232,037	$ 589,708	$ 549,401
Onshore Natural Gas Pipelines & Services	75,424	77,489	235,102	260,943
Offshore Pipelines & Services	46,676	38,364	97,429	76,131
Petrochemical Services	51,412	51,851	139,329	136,413
Total segment gross operating margin	$ 363,721	$ 399,741	$ 1,061,568	$ 1,022,888

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before provision for income taxes, minority interest and the cumulative effect of change in accounting principle, see Other Items Non-GAAP reconciliations included within this Item 2.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
NGL Pipelines & Services:				
Sale of NGL products	$ 2,837,465	$ 2,640,568	$ 7,952,147	$ 7,276,342
Percent of consolidated revenues	69%	68%	68%	68%
Onshore Natural Gas Pipelines & Services:				
Sale of natural gas	406,482	312,116	1,190,235	943,480
Percent of consolidated revenues	10%	8%	10%	9%
Petrochemical Services:				
Sale of petrochemical products	444,670	417,395	1,268,731	1,157,184

Percent of consolidated revenues	11%	11%	11%	11%

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

Comparison of Three Months Ended September 30, 2007 with Three Months Ended September 30, 2006

Consolidated revenues increased $239.5 million quarter-to-quarter to $4.11 billion for the third quarter of 2007 from $3.87 billion for the third quarter of 2006. The quarter-to-quarter increase in consolidated revenues is primarily due to higher NGL sales prices and natural gas sales volumes in the third quarter of 2007 relative to the third quarter of 2006. These factors contributed to a $318.5 million increase in consolidated revenues from our NGL, natural gas and petrochemical marketing activities. Revenues for the third quarter of 2007 include $2.0 million of proceeds from business interruption insurance claims compared to $50.2 million of such proceeds received during the third quarter of 2006. See Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements for additional information regarding proceeds from our business interruption insurance claims.

Operating costs and expenses were $3.90 billion for the third quarter of 2007 versus $3.58 billion for the third quarter of 2006. The $311.6 million quarter-to-quarter increase in consolidated operating costs and expenses is primarily due to a $321.2 million increase in the cost of sales associated with our NGL, natural gas and petrochemical marketing activities caused by higher sales volumes and energy commodity prices. General and administrative costs were $18.7 million for the third quarter of 2007 compared to $15.8 million for the third quarter of 2006.

Changes in our revenues and costs and expenses quarter-to-quarter are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.21 per gallon during the third quarter of 2007 versus $1.09 per gallon during the third quarter of 2006. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub) averaged $6.16 per MMBtu during the third quarter of 2007 versus $6.58 per MMBtu during the third quarter of 2006. For additional historical energy commodity pricing information, see the table on page 49.

Equity earnings from our unconsolidated affiliates were $14.0 million for the third quarter of 2007 compared to $2.3 million for the third quarter of 2006. The third quarter of 2006 included a $7.4 million non-cash impairment charge related to our investment in Neptune Pipeline Company, L.L.C. (Neptune). The third quarter of 2007 includes $2.4 million of equity earnings from our investment in Jonah. Certain capital spending thresholds and operational milestones were achieved during the third quarter of 2007 with respect to the Phase V Expansion of the Jonah Gathering System. We earned a fixed 19.4% interest in Jonah as a result.

Operating income for the third quarter of 2007 was $210.8 million compared to $274.2 million for the third quarter of 2006. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $63.4 million decrease in operating income quarter-to-quarter.

Interest expense increased $22.3 million quarter-to-quarter primarily due to our issuance of junior subordinated notes in the third quarter of 2006 and the second quarter of 2007 and the issuance of Senior Notes L in the third quarter of 2007. Our consolidated interest expense for the third quarter of 2007 includes $3.2 million associated with Duncan Energy Partners credit facility. Our average debt principal outstanding was $6.6 billion in the third quarter of 2007 compared to $5.0 billion in the third quarter of 2006. Minority interest expense increased $5.8 million quarter-to-quarter attributable to the public unit holders of Duncan Energy Partners and third-party ownership interests in the Independence Hub platform.

As a result of items noted in the previous paragraphs, our consolidated net income decreased $90.7 million quarter-to-quarter to $117.6 million in the third quarter of 2007 compared to $208.3 million in the third quarter of 2006.

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

NGL Pipelines & Services. Gross operating margin from this business segment was $190.2 million for the third quarter of 2007 compared to $232.0 million for the third quarter of 2006. The third quarter of 2007 includes $1.8 million of proceeds from business interruption insurance claims compared to $30.1 million of proceeds during the third quarter of 2006. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $96.1 million for the third quarter of 2007 compared to $107.9 million for the third quarter of 2006. Equity NGL production decreased to 64 MBPD during the third quarter of 2007 from 67 MBPD during the third quarter of 2006. The $11.8 million quarter-to-quarter decrease in gross operating margin is primarily due to lower NGL marketing sales volumes and increased natural gas hedging expenses. In addition, the third quarter of 2007 includes expenses attributable to a delay in the initial start-up of our Meeker natural gas processing plant, which commenced operations in October 2007 approximately two months later than our original expectations.

Gross operating margin from our NGL pipelines and related storage business was $71.2 million for the third quarter of 2007 compared to $56.6 million for the third quarter of 2006. Total NGL transportation volumes decreased to 1,575 MBPD during the third quarter of 2007 from 1,706 MBPD during the third quarter of 2006 primarily attributable to lower import volumes. The $14.6 million quarter-to-quarter increase in gross operating margin from this business is primarily due to higher NGL transportation volumes and tariffs on our Mid-America Pipeline System during the third quarter of 2007 relative to the same quarter in 2006 and the addition of gross operating margin from the DEP South Texas NGL Pipeline, which became operational in January 2007, both of which were partially offset by the effects of lower import volumes.

Gross operating margin from NGL fractionation was $21.1 million for the third quarter of 2007 compared to $37.4 million for the third quarter of 2006. Fractionation volumes increased to 371 MBPD during the third quarter of 2007 from 341 MBPD during the third quarter of 2006. The $16.3 million quarter-to-quarter decrease in gross operating margin is largely due to (i) lower measurement gains during the third quarter of 2007 relative to the same quarter in 2006, (ii) a 7 MBPD decrease in fractionation volumes and higher operating expenses at our Norco NGL fractionator and (iii) start-up costs for our Hobbs NGL fractionator. The Hobbs NGL fractionator became operational in August 2007 and accounted for 22 MBPD of the quarter-to-quarter increase in fractionation volumes.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $75.4 million for the third quarter of 2007 compared to $77.5 million for the third quarter of 2006. Gross operating margin from our onshore natural gas pipeline business was $67.8 million for the third quarter of 2007 compared to $76.4 million for the third quarter of 2006. Onshore natural gas transportation volumes increased to 6,597 BBtu/d during the third quarter of 2007 from 6,049 BBtu/d for the third quarter of 2006. The $8.6 million quarter-to-quarter decrease in gross operating margin from this business is primarily due to lower volumes on our San Juan Gathering System and higher pipeline integrity and operating expenses on our Texas Intrastate System.

Segment gross operating margin for the third quarter of 2007 includes $1.4 million from the Piceance Creek Gathering System, which we acquired in December 2006 and placed in-service during January 2007, and $2.4 million of equity earnings from Jonah. The Piceance Creek Gathering System and our net share of the gathering volumes on the Jonah Gathering System contributed 404 BBtu/d and 359 BBtu/d, respectively, of natural gas gathering volumes during the third quarter of 2007.

Gross operating margin from our natural gas storage business increased $6.6 million quarter-to-quarter primarily due to a decrease in repair-related costs at our Wilson natural gas storage facility. Three storage wells at our Wilson facility were taken out of service in the second quarter of 2006 One cavern resumed limited operations during October 2007 and the remaining two storage wells are expected to resume commercial operations in the fourth quarter of 2007. Also, gross operating margin for the third quarter of 2007 includes a $2.4 million charge for the write-off of accumulated conversion costs related to a cavern at the Petal storage facility in Mississippi that was deemed unsuitable to convert from NGL to natural gas storage service.

Offshore Pipelines & Services. Gross operating margin from this business segment was $46.7 million for the third quarter of 2007 compared to $38.4 million for the third quarter of 2006. Segment gross operating margin for the third quarter of 2007 includes $0.2 million of proceeds from business interruption insurance claims compared to $20.1 million of proceeds in the third quarter of 2006. The

following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our offshore platforms and services business was $28.8 million for the third quarter of 2007 compared to $8.6 million for the third quarter of 2006. The $20.2 million quarter-to-quarter increase in gross operating margin is primarily due to our Independence Hub platform, which began earning revenues in March 2007. The Independence Hub received first production in July 2007 and contributed $16.4 million of the increase in gross operating margin quarter-to-quarter from fixed and volumetric revenues earned on an average throughput of 124 MMcf/d of natural gas during the third quarter of 2007.

Gross operating margin from our offshore natural gas pipeline business was $8.8 million for the third quarter of 2007 compared to $0.9 million for the third quarter of 2006, an increase of $7.9 million quarter-to-quarter. Offshore natural gas transportation volumes were 1,271 BBtu/d during the third quarter of 2007 versus 1,573 BBtu/d during the third quarter of 2006. The third quarter of 2006 includes a $7.4 million non-cash impairment charge related to our investment in Neptune. Gross operating margin from our HIOS system increased $4.6 million quarter-to-quarter primarily due to an increase in the tariff rate charged to shippers. Also, gross operating margin for the third quarter of 2007 includes $3.1 million from our Independence Trail pipeline, which became operational in July 2007. Collectively, gross operating margin from our other natural gas pipelines decreased $7.2 million quarter-to-quarter primarily due to lower volumes.

Gross operating margin from our offshore crude oil pipeline business was $8.9 million for the third quarter of 2007 compared to $8.8 million for the third quarter of 2006. Offshore crude oil transportation volumes decreased to 163 MBPD during the third quarter of 2007 from 173 MBPD during the third quarter of 2006. Equity earnings from Cameron Highway increased $2.7 million quarter-to-quarter attributable to higher volumes and lower interest expense. Collectively, gross operating margin from our other offshore crude oil pipelines decreased $2.6 million quarter-to-quarter primarily due to lower transportation volumes during the third quarter of 2007 compared to the same quarter in 2006.

Petrochemical Services. Gross operating margin from this business segment was $51.4 million for the third quarter of 2007 compared to $51.9 million for the third quarter of 2006. Gross operating margin from our butane isomerization business was $28.5 million for the third quarter of 2007 compared to $18.5 million for the third quarter of 2006. The $10.0 million quarter-to-quarter increase in gross operating margin is primarily due to a 17% increase in volumes, which increased to 96 MBPD during the third quarter of 2007 from 82 MBPD during the third quarter of 2006.

Gross operating margin from our octane enhancement business was $8.9 million for the third quarter of 2007 compared to $18.4 million for the third quarter of 2006. Gross operating margin from this business decreased $9.5 million quarter-to-quarter primarily due to lower isooctane sales margins and higher maintenance expenses in the third quarter of 2007 versus the third quarter of 2006. Gross operating margin from our propylene fractionation and pipeline business was $14.0 million for the third quarter of 2007 versus $14.9 million for the third quarter of 2006. The $0.9 million quarter-to-quarter decrease in gross operating margin is largely due to higher maintenance expenses during the third quarter of 2007 compared to the third quarter of 2006.

Comparison of Nine Months Ended September 30, 2007 with

Nine Months Ended September 30, 2006

Revenues for the first nine months of 2007 were $11.65 billion compared to $10.64 billion for the first nine months of 2006. The $1.01 billion period-to-period increase in consolidated revenues is primarily due to higher sales volumes and energy commodity prices during the first nine months of 2007 relative to the 2006 period. These differences accounted for a $1.03 billion increase in consolidated revenues associated with our marketing activities. Revenues for the first nine months of 2007 include $24.9 million of proceeds from business interruption insurance claims compared to $62.4 million of proceeds during the first nine months of 2006. In addition, revenues from recent business combinations or newly constructed

assets (principally those attributable to the Encinal acquisition and the Independence Hub platform) increased $87.1 million period-to-period.

Operating costs and expenses were $10.98 billion for the first nine months of 2007 compared to $9.96 billion for the first nine months of 2006. The $1.02 billion period-to-period increase in consolidated operating costs and expenses is largely due to an increase in the costs of sales associated with our marketing activities. The cost of sales of our natural gas, NGL and petrochemical products increased $738.3 million period-to-period as a result of an increase in volumes and higher energy commodity prices. Consolidated operating costs and expenses attributable to recent business combinations or newly constructed assets increased $114.7 million period-to-period.

General and administrative costs were $66.7 million for the first nine months of 2007 compared to $45.8 million for the first nine months of 2006. The $20.9 million period-to-period increase in general and administrative costs is primarily due to the recognition of a severance obligation during the first nine months of 2007 and an increase in legal fees.

Changes in our revenues and costs and expenses period-to-period are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.09 per gallon for the first nine months of 2007 versus $1.02 per gallon during the first nine months of 2006. The Henry Hub market price for natural gas averaged $6.83 per MMBtu for the first nine months of 2007 versus $7.47 per MMBtu during the 2006 period.

Equity earnings from unconsolidated affiliates decreased $0.4 million to $13.9 million for the first nine months of 2007 compared to $14.3 million for the 2006 period. The first nine months of 2007 include a $7.0 million non-cash impairment charge associated with our investment in Nemo Gathering Company, LLC (Nemo) compared to a $7.4 million charge related to our investment in Neptune during the 2006 period. Equity earnings from our investment in Cameron Highway decreased $5.0 million period-to-period primarily due to expenses we recognized during first nine months of 2007 associated with the early retirement of Cameron Highway s debt. The first nine months of 2007 include $4.4 million of equity earnings from our investment in Jonah.

Operating income for the first nine months of 2007 was $613.3 million compared to $653.7 million for the first nine months of 2006. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $40.4 million decrease in operating income period-to-period.

Interest expense increased to $219.7 million for the first nine months of 2007 from $177.2 million for the first nine months of 2006. The $42.5 million period-to-period increase in interest expense is primarily due to higher outstanding debt principal balances during the first nine months of 2007 compared to the same period in 2006. Our average debt principal outstanding was $6.0 billion for the first nine months of 2007 compared to $4.8 billion for the first nine months of 2006. Also, our consolidated interest expense for the first nine months of 2007 includes $6.7 million associated with Duncan Energy Partners credit facility. Minority interest expense increased $14.5 million period-to-period attributable to the public unitholders of Duncan Energy Partners and third-party ownership interests in the Independence Hub platform.

As a result of the items noted in previous paragraphs, our consolidated net income decreased $96.6 million to $371.8 million for the nine months ended September 30, 2007 compared to $468.4 million for the 2006 period. The first nine months of 2006 include a $1.5 million benefit related to the cumulative effect of a change in accounting principle resulting from our adoption of Statement of Financial Accounting Standards (SFAS) 123(R) on January 1, 2006. For additional information regarding this cumulative effect adjustment, please read Note 2 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

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

NGL Pipelines & Services. Gross operating margin from this business segment was $589.7 million for the first nine months of 2007 compared to $549.4 million for the first nine months of 2006, a period-to-period increase of $40.3 million. The first nine months of 2007 include $23.4 million of proceeds from business interruption insurance claims compared to $40.4 million of proceeds during the first nine months of 2006. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $283.5 million for the first nine months of 2007 compared to $268.9 million for the first nine months of 2006. The $14.6 million period-to-period increase in gross operating margin is primarily due to higher processing volumes at our south Louisiana and Chaco natural gas processing plants during the first nine months of 2007 relative to the 2006 period. Fee-based processing volumes increased to 2.4 Bcf/d during the first nine months of 2007 from 2.2 Bcf/d during the first nine months of 2006. Equity NGL production volumes increased to 67 MBPD during the first nine months of 2007 from 63 MBPD during the 2006 period.

Gross operating margin from our NGL pipelines and storage business was $215.5 million for the first nine months of 2007 compared to $175.7 million for the first nine months of 2006. Total NGL transportation volumes increased to 1,626 MBPD for the first nine months of 2007 from 1,579 MBPD for the 2006 period. The $39.8 million period-to-period increase in gross operating margin is largely due to higher pipeline transportation and NGL storage volumes at certain of our facilities and higher transportation fees charged to shippers on our Mid-America Pipeline System. In addition, the first nine months of 2007 include $15.3 million of gross operating margin generated by the DEP South Texas NGL Pipeline.

Gross operating margin from our NGL fractionation business was $67.3 million for the first nine months of 2007 compared to $64.4 million for the first nine months of 2006. Fractionation volumes increased from 302 MBPD during the first nine months of 2006 to 379 MBPD during the first nine months of 2007. The $2.9 million period-to-period increase in gross operating margin is primarily due to higher volumes at our Norco NGL fractionator during the first nine months of 2007 relative to the 2006 period. Our Norco NGL fractionator returned to normal operating rates in the second quarter of 2006 after suffering a reduction of processing volumes due to the effects of Hurricane Katrina.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $235.1 million for the first nine months of 2007 compared to $260.9 million for the first nine months of 2006. Gross operating margin from our onshore natural gas pipeline business was $216.2 million for the first nine months of 2007 compared to $246.6 million for the 2006 period. Onshore natural gas transportation volumes were 6,576 BBtu/d during the first nine months of 2007 compared to 6,066 BBtu/d during the 2006 period. The $30.4 million period-to-period decrease in gross operating margin is largely due to lower natural gas sales margins on our Acadian and Permian Basin Systems and higher pipeline integrity and operating costs on our Texas Intrastate System.

The first nine months of 2007 include $3.6 million of gross operating margin from our Piceance Creek Gathering System and $4.4 million of equity earnings from Jonah. The Piceance Creek Gathering System and our net share of the gathering volumes on the Jonah Gathering System contributed 718 BBtu/d, collectively, of natural gas gathering volumes during the first nine months of 2007.

Gross operating margin from our natural gas storage business was $18.9 million for the first nine months of 2007 compared to $14.3 million for the first nine months of 2006. The $4.6 million increase period-to-period is largely due to lower repair-related costs at our Wilson natural gas storage facility.

Offshore Pipelines & Services. Gross operating margin from this business segment was $97.4 million for the first nine months of 2007 compared to $76.1 million for the first nine months of 2006. The first nine months of 2007 include $1.5 million of proceeds from business interruption insurance claims compared to $22.0 million of proceeds during the first nine months of 2006. In addition, insurance costs for our offshore assets increased to $20.1 million for the first nine months of 2007 compared to $13.8 million for the first nine months of 2006. Insurance costs for our offshore operations have increased as a result of industry losses associated with significant storms in recent years. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims and insurance costs.

Gross operating margin from our offshore platforms and services business was $69.5 million for the first nine months of 2007 compared to $23.4 million for the first nine months of 2006. The $46.1 million period-to-period increase is primarily due to our Independence Hub platform, which contributed $34.1 million of gross operating margin for the first nine months of 2007. In addition, gross operating margin from this business increased $12.0 million period-to-period primarily due to higher volumes during the first nine months of 2007 compared to the 2006 period.

Gross operating margin from our offshore natural gas pipeline business was $34.6 million for the first nine months of 2007 compared to $28.3 million for the first nine months of 2006. Offshore natural gas transportation volumes were 1,322 BBtu/d during the first nine months of 2007 versus 1,524 BBtu/d during the first nine months of 2006. The $6.3 million increase period-to-period in gross operating margin is primarily due to an increase in the tariff rate charged to shippers on HIOS. The first nine months of 2007 includes a $7.0 million non-cash impairment charge associated with our investment in Nemo compared to a $7.4 million charge related to our investment in Neptune during the 2006 period. Also, the first nine months of 2007 include $3.1 million of gross operating margin from the Independence Trail pipeline.

Gross operating margin from our offshore crude oil pipeline business was $11.9 million for the first nine months of 2007 versus $16.2 million for the first nine months of 2006. Offshore crude oil transportation volumes were 164 MBPD for the first nine months of 2007 compared to 149 MBPD for the first nine months of 2006. Improved gross operating margin period-to-period from our Marco Polo, Constitution and Poseidon Oil Pipelines was more than offset by a one-time expense of $8.8 million in the first nine months of 2007 associated with the early termination of Cameron Highway s credit facility. Collectively, gross operating margin from our Marco Polo, Constitution and Poseidon Oil Pipelines increased $2.7 million period-to-period due to higher volumes and fees.

Petrochemical Services. Gross operating margin from this business segment was $139.3 million for the first nine months of 2007 compared to $136.4 million for the first nine months of 2006. Gross operating margin from butane isomerization was $71.7 million for the first nine months of 2007 compared to $57.1 million for the first nine months of 2006. Butane isomerization volumes increased to 93 MBPD during the first nine months of 2007 from 83 MBPD during the first nine months of 2006. The $14.6 million period-to-period increase in gross operating margin is largely due to higher processing volumes.

Gross operating margin from our octane enhancement business was $22.1 million for the first nine months of 2007 compared to $27.8 million for the first nine months of 2006. The $5.7 million period-to-period decrease in gross operating margin is primarily due to lower sales margins. Gross operating margin from our propylene fractionation business was $45.6 million for the first nine months of 2007 versus $51.5 million for the first nine months of 2006. The $5.9 million period-to-period decrease in gross operating margin is largely due to lower propylene sales margins and higher power-related costs in the first nine months of 2007 versus the 2006 period.

Liquidity and Capital Resources

At September 30, 2007, we had $43.9 million of unrestricted cash on hand and approximately $1.1 billion of available credit under EPO s Multi-Year Revolving Credit Facility. At September 30, 2007, there was approximately $83.9 million of available credit under Duncan Energy Partners Credit Facility. We had approximately $6.8 billion in principal outstanding under consolidated debt agreements at September 30, 2007. We were in compliance with the financial and other compliance requirements of our consolidated debt obligations at September 30, 2007.

We believe that we will have access to capital markets and continue to have adequate liquidity to fund future recurring operating and investing activities. Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business acquisitions and distributions to our partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and short-term revolving credit arrangements. Capital expenditures for long-term needs resulting from internal growth projects and business acquisitions are expected to be funded by a variety of sources (either separately or in combination) including operating cash flows, borrowings under credit facilities, the issuance of additional equity and debt securities and proceeds from divestitures of ownership interest in assets to affiliates or third parties. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

Registration Statements

We may issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. Duncan Energy Partners may do likewise in meeting its liquidity and capital spending requirements. Enterprise Products Partners L.P. and EPO have a universal shelf registration statement on file with the U.S. Securities and Exchange Commission (SEC) that would allow these entities to issue an unlimited amount of debt and equity securities for general partnership purposes.

In addition, Enterprise Products Partners has filed a registration statement with the SEC authorizing the issuance of up to 25,000,000 of its common units in connection with a distribution reinvestment plan (DRIP). The DRIP provides Enterprise Products Partners unitholders of record and beneficial owners of its 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 from Enterprise Products Partners into the purchase of additional common units. During the nine-month period ended September 30, 2007, Enterprise Products Partners issued 1,518,291 of its common units in connection with the DRIP and a related plan. The issuance of these common units generated $45.3 million in proceeds.

Credit Ratings of EPO

At November 1, 2007, the investment-grade credit ratings of EPO s debt securities were Baa3 by Moody s Investor Services (Moody s); BBB- by Fitch Ratings (Fitch); and BBB- by Standard and Poor s (S&P). A rating reflects only the view of a rating agency and is not a recommendation to buy, sell or hold any indebtedness. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it determines that the circumstances warrant such a change and should be evaluated independently of any other rating.

Cash Flows from Operating, Investing and Financing Activities

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

	For the Nine Months Ended September 30,	
	2007	**2006**
Net cash flows provided by operating activities	$ 937,835	$ 986,024

Cash used in investing activities	2,039,495	1,217,238
Cash provided by financing activities	1,122,575	306,516

Net cash flows provided by operating activities are largely dependent on earnings from our business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide services for producers and consumers of natural gas, NGLs and crude oil. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; feedstocks in petrochemical manufacturing; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of general economic conditions, reduced demand for the end products made with our products or increased competition from other service providers or producers due to pricing differences or other reasons could have a negative impact on our earnings and thus the availability of cash from operating activities.

Operating activities. Net cash flows from operating activities was $937.8 million for the nine months ended September 30, 2007 compared to $986.0 million for the same period in 2006. The following information highlights significant factors that influenced the $48.2 million period-to-period decrease in net cash flows from operating activities:

§ Cash proceeds from business interruption and property damage claims decreased $63.4 million period-to-period. For information regarding such proceeds, see Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

§ Excluding cash proceeds from insurance claims, the timing of other cash receipts and payments related to our operations increased $36.8 million period-to-period primarily due to timing considerations and higher gross operating margins.

§ Cash payments for interest increased $43.1 million period-to-period primarily due to higher debt balances resulting from our capital spending program.

§ Cash distributions received from unconsolidated affiliates increased $25.3 million period-to-period primarily due to improved earnings from our Gulf of Mexico investments, which were negatively impacted during the nine months ended September 30, 2006 due to the lingering effects of Hurricanes Katrina and Rita.

Investing activities. Cash used in investing activities was $2.04 billion for the nine months ended September 30, 2007 compared to $1.22 billion for the same period in 2006. The $822.3 million increase in net cash outflows is primarily due to a $747.8 million increase in capital spending between periods. The following table summarizes our cash basis capital spending by activity for the periods indicated (dollars in thousands):

	For the Nine Months Ended September 30,	
	2007	**2006**
Capital spending for business combinations:		
Encinal acquisition, excluding non-cash equity consideration (1)	$ --	$ 144,973
Additional ownership interests in Dixie Pipeline Company (Dixie) and other	785	--
Total	785	144,973
Capital spending for property, plant and equipment, net: (2)		
Growth capital projects (3)	1,531,679	881,397
Sustaining capital projects (4)	100,314	95,274
Total	1,631,993	976,671
Capital spending attributable to unconsolidated affiliates:		
Investments in and advances to unconsolidated affiliates (5)	329,115	92,434
Total	329,115	92,434
Total capital spending	$ 1,961,893	$ 1,214,078

(1) Excludes $181.1 million of non-cash consideration paid to the seller in the form of 7,115,844 of our common units. See Note 16 of the Notes to Unaudited Condensed Consolidated Financial Statements for additional information regarding our business combinations.

(2) On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. Such contributions in aid of construction costs were $52.3 million and $63.7 million for the nine months ended September 30, 2007 and 2006, respectively.

(3) Growth capital projects either (i) result in additional revenue streams from existing assets or (ii) expand our asset base through construction of new facilities that will generate additional revenue streams.

(4) Sustaining capital expenditures are capital expenditures (as defined by GAAP) resulting from improvements to and major renewals of existing assets. Such expenditures serve to maintain existing operations but do not generate additional revenues.

(5) The 2007 period includes $216.5 million in cash contributions to Cameron Highway Oil Pipeline Company (Cameron Highway) to fund our share of the repayment of its debt obligations.

Based on information currently available, we estimate our consolidated capital spending for the fourth quarter of 2007 will approximate $590.0 million, which includes estimated expenditures of $550.0 million for growth capital projects and acquisitions and $40.0 million for sustaining capital expenditures. For information regarding selected major growth capital projects, please see Capital Spending under Item 7 of the annual report on Form 10-K for the year ended December 31, 2006.

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

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

At September 30, 2007, we had $534.0 million in outstanding purchase commitments. These commitments primarily relate to growth capital projects in the Rocky Mountains that are expected to be placed in service in 2007 and 2008 and the Shenzi Oil Export Pipeline Project, which is expected to be completed in 2009.

Cameron Highway repaid its $365.0 million Series A notes and $50.0 million Series B notes in May and June 2007, respectively, using cash contributions from its partners. We funded our 50% share of the capital contributions using borrowings under EPO s Multi-Year Revolving Credit Facility. Cameron Highway incurred an $11.0 million make-whole premium in connection with the repayment of its Series A notes.

Cash outflows related to current and long-term restricted cash amounts increased by $73.3 million period-to-period primarily due to $39.3 million of Petal GO Zone bond proceeds held by a trustee and an increase in cash deposits at a brokerage firm in connection with our commodity hedging activities. See Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements for additional information regarding the Petal GO Zone bonds.

Financing activities. Cash provided by financing activities was $1.12 billion for the nine months ended September 30, 2007 versus $306.5 million for the same period in 2006. The following information highlights significant factors that influenced the $816.1 million period-to-period change in cash provided by financing activities:

§ Net borrowings under our consolidated debt agreements increased $1.41 billion period-to-period. In May 2007, EPO sold $700.0 million in principal amount of fixed/floating unsecured junior subordinated notes (Junior Notes B). In September 2007, EPO sold $800.0 million in principal amount of fixed-rate unsecured senior notes (Senior Notes L). For information regarding our consolidated debt obligations, see Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

§ Net proceeds from the issuance of our common units decreased $790.2 million period-to-period. We had underwritten equity offerings in March and September of 2006 that generated net proceeds of $750.8 million reflecting the sale of 31,050,000 common units.

§ Contributions from minority interests increased $279.9 million period-to-period primarily due to the initial public offering of Duncan Energy Partners in February 2007, which generated net proceeds of $290.5 million from the sale of 14,950,000 of its common units. See Other Items Initial Public Offering of Duncan Energy Partners within this Item 2 for additional information regarding this offering.

§ Cash distributions to our partners increased $95.5 million period-to-period due to an increase in common units outstanding and our quarterly cash distribution rates.

§ We received $48.9 million from the settlement of treasury lock contracts during the nine months ended September 30, 2007 related to our interest rate hedging activities.

Other Items

Initial Public Offering of Duncan Energy Partners

In September 2006, we formed a consolidated subsidiary, Duncan Energy Partners, to acquire, own and operate a diversified portfolio of midstream energy assets. On February 5, 2007, this subsidiary completed its initial public offering of 14,950,000 common units (including an overallotment amount of 1,950,000 common units) at $21.00 per unit, which generated net proceeds to Duncan Energy Partners of $291.9 million. As consideration for assets contributed and reimbursement for capital expenditures related to these assets, Duncan Energy Partners distributed $260.6 million of these net proceeds to us along with $198.9 million in borrowings under its credit facility and a final amount of 5,351,571 common units of Duncan Energy Partners. Duncan Energy Partners used $38.5 million of net proceeds from the overallotment to redeem 1,950,000 of the 7,301,571 common units it had originally issued to Enterprise

Products Partners, resulting in a final amount of 5,351,571 common units beneficially owned by Enterprise Products Partners. We used the cash received from Duncan Energy Partners to temporarily reduce amounts outstanding under EPO s Multi-Year Revolving Credit Facility.

For additional information regarding our relationship with Duncan Energy Partners, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements. We may contribute or sell other equity interests in our subsidiaries to Duncan Energy Partners and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program. We have no obligation or commitment to make such contributions or sales to Duncan Energy Partners.

Contractual Obligations

With the exception of the debt incurred by Duncan Energy Partners in connection with its initial public offering and the issuances of Junior Notes B and Senior Notes L by EPO, there have been no significant changes in our scheduled maturities of long-term debt since those reported in our annual report on Form 10-K for the year ended December 31, 2006. See Note 9 of the Notes to the Unaudited Condensed Consolidated Financial Statements under Item 1 of this quarterly report for additional information regarding the debt obligations of Duncan Energy Partners and the issuances of Junior Notes B and Senior Notes L.

There have been no material changes in our operating lease commitments since December 31, 2006, except for the commitments associated with a new natural gas storage lease. See Note 14 of the Notes to the Unaudited Condensed Consolidated Financial Statements under Item 1 of this quarterly report for additional information regarding the incremental operating lease obligations associated with our new natural gas storage lease agreement.

The following table presents our consolidated debt obligations and related estimates of cash interest payments after giving effect to the debt incurred by Duncan Energy Partners and EPO s issuances of Junior Notes B and Senior Notes L as of September 30, 2007. In addition, the following table presents the incremental operating lease obligations associated with our new natural gas storage lease (dollars in thousands):

		Payment or Settlement due by Period			
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**More than 5 years**
Scheduled maturities of long-term debt (1)	$ 6,796,568	$ --	$ 1,069,068	$ 1,270,000	$ 4,457,500
Estimated cash payments for interest (2)	$ 9,133,378	$ 435,093	$ 840,517	$ 652,263	$ 7,205,505
Incremental operating lease obligations	$ 7,344	$ 4,896	$ 2,448	$ --	$ --

(1) Represents payment obligations under our consolidated debt agreements, including those of Duncan Energy Partners as of September 30, 2007. Amounts presented in the table represent the scheduled future maturities of long-term debt principal for the periods indicated.

(2) Represents estimates of future cash payments of interest assuming that principal amounts outstanding and the interest rates charged both remain at September 30, 2007 levels.

Off-Balance Sheet Arrangements

In May 2007, we made a $191.0 million cash contribution to Cameron Highway. This capital contribution, along with an equal amount contributed by our joint venture partner in Cameron Highway, was used by Cameron Highway to repay $365.0 million outstanding under its Series A notes and $14.1 million of related make-whole premiums and accrued interest. In June 2007, we and our joint venture partner in Cameron Highway made an additional capital contribution of approximately $25.5 million each. These capital contributions were used by

Cameron Highway to repay its Series B notes. The amount of the repayment was $50.9 million, which included $0.9 million of related make-whole premiums and accrued interest. As a result of these events, Cameron Highway no longer has any outstanding debt.

Apart from the repayment of Cameron Highway s Series A and B notes, there have been no significant changes with regards to our off-balance sheet arrangements since those reported in our annual report on Form 10-K for the year ended December 31, 2006.

Summary of Related Party Transactions

The following table summarizes our related party transactions for the periods indicated (dollars in thousands).

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Revenues from consolidated operations:				
EPCO and affiliates	$ 91,630	$ 47,812	$ 164,299	$ 86,892
Unconsolidated affiliates	87,209	84,551	215,015	248,980
Total	$ 178,839	$ 132,363	$ 379,314	$ 335,872
Operating costs and expenses:				
EPCO and affiliates	$ 74,910	$ 78,570	$ 228,264	$ 244,632
Unconsolidated affiliates	6,414	4,523	22,628	19,113
Total	$ 81,324	$ 83,093	$ 250,892	$ 263,745
General and administrative costs:				
EPCO and affiliates	$ 11,504	$ 10,728	$ 45,292	$ 32,566

For additional information regarding our related party transactions, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

We have an extensive and ongoing relationship with EPCO and its affiliates, including TEPPCO and Energy Transfer Equity. Our revenues from EPCO and affiliates are primarily associated with sales of NGL products. Our expenses with EPCO and affiliates are primarily due to (i) reimbursements we pay EPCO in connection with an administrative services agreement and (ii) purchases of NGL products. TEPPCO is an affiliate of ours due to the common control relationship of both entities. Enterprise GP Holdings acquired non-controlling ownership interests in both ETE GP and Energy Transfer Equity in May 2007. As a result of this transaction, ETE GP and Energy Transfer Equity became related parties to us.

Many of our unconsolidated affiliates perform supporting or complementary roles to our consolidated business operations. The majority of our revenues from unconsolidated affiliates relate to natural gas sales to a Louisiana affiliate. The majority of our expenses with unconsolidated affiliates pertain to payments we make to K/D/S Promix, L.L.C. for NGL transportation, storage and fractionation services.

On February 5, 2007, our consolidated subsidiary, Duncan Energy Partners, completed an underwritten initial public offering of its common units. Duncan Energy Partners was formed in September 2006 as a Delaware limited partnership to, among other things, acquire ownership interests in certain of our midstream energy businesses. For additional information regarding Duncan Energy Partners, see Other Items Initial Public Offering of Duncan Energy Partners within this section.

Non-GAAP reconciliations

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Total segment gross operating margin	$ 363,721	$ 399,741	$ 1,061,568	$ 1,022,888
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(133,869)	(112,412)	(374,522)	(325,180)
Operating lease expense paid by EPCO	(526)	(526)	(1,579)	(1,582)
Loss (gain) on sale of assets in operating costs and expenses	219	3,204	(5,445)	3,401
General and administrative costs	(18,715)	(15,823)	(66,706)	(45,798)
Consolidated operating income	210,830	274,184	613,316	653,729
Other expense, net	(83,369)	(60,657)	(213,327)	(169,705)
Income before provision for income taxes, minority interest and cumulative effect of change in accounting principle	$ 127,461	$ 213,527	$ 399,989	$ 484,024

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

Cumulative effect of change in accounting principle

Net income for the first quarter of 2006 includes a non-cash benefit of $1.5 million related to the cumulative effect of a change in accounting principle resulting from our adoption of SFAS 123(R) on January 1, 2006.

Recent Accounting Pronouncements

The accounting standard setting bodies and the SEC have recently issued the following accounting guidance that will or may affect our financial statements:

- § SFAS 157, Fair Value Measurements, and
- § SFAS 159, Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115.

For additional information regarding these recent accounting developments and others that may affect our future financial statements, see Note 2 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Amendment to Enterprise Products GP Limited Liability Company Agreement

On November 7, 2007, Enterprise Products GP amended and restated its limited liability company agreement to provide, among other things, that:

§ to the fullest extent permitted by law, any action (or inaction) taken (or omitted) by its independent directors consistent with our Partnership Agreement shall be permitted and deemed approved by Enterprise GP Holdings, the sole member of our general partner, and shall not constitute a breach of Enterprise Products GP s limited liability company agreement, our Partnership Agreement or of any duty stated or implied by law or equity; and

§ the duties and obligations that Enterprise Products GP s officers and directors owe to us are limited as set forth in our Partnership Agreement.

Pipeline Integrity Costs

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

	For the Three Months Ended September 30,		**For the Nine Months Ended September 30,**	
	2007	**2006**	**2007**	**2006**
Pipeline Integrity Costs				
Operating Expense	$ 11,315	$ 7,097	$ 34,987	$ 21,389
Capitalized	15,679	15,539	41,543	32,894
Total	$ 26,994	$ 22,636	$ 76,530	$ 54,283

We expect our net cash outlay for pipeline integrity program expenditures to approximate $15.6 million for the remainder of 2007. Our forecast is net of certain costs we recovered from El Paso in connection with an indemnification agreement. During the second and third quarter of 2007, we received $30.9 million and $0.2 million, respectively, from El Paso related to our 2006 expenditures. During the second quarter of 2007 we reached the maximum amount reimbursable under the indemnification agreement. We billed and received a final amount of $5.4 million from El Paso for 2007 pipeline integrity costs during October 2007.

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

We are exposed to financial market risks, including changes in commodity prices and interest rates. In addition, we are exposed to fluctuations in exchange rates between the U.S. dollar and Canadian dollar. 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. As a matter of policy, we do not use financial instruments for speculative (or trading) purposes.

Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed 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. The following information summarizes significant components of our interest rate risk hedging portfolio:

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Fair value hedges Interest rate swaps

As summarized in the following table, we had eleven interest rate swap agreements outstanding at September 30, 2007 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 Amount
Senior Notes B, 7.50% fixed rate, due Feb. 2011	1	Jan. 2004 to Feb. 2011	Feb. 2011	7.50% to 8.65%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.38% to 7.19%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 6.30%	$600 million
Senior Notes K, 4.95% fixed rate, due June 2010	2	Aug. 2005 to June 2010	June 2010	4.95% to 5.80%	$200 million

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

The total fair value of these eleven interest rate swaps at September 30, 2007 and December 31, 2006, was a liability of $19.7 million and $29.1 million, respectively, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the three months ended September 30, 2007 and 2006 includes losses of $2.3 million and $1.9 million from these swap agreements, respectively. For the nine months ended September 30, 2007 and 2006, interest expense includes losses of $6.9 million and $2.8 million, respectively, from these swap agreements.

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

Scenario	Resulting Classification	Swap Fair Value at September 30, 2007	October 29, 2007
FV assuming no change in underlying interest rates	*Liability*	$ (19,720)	$ (10,710)
FV assuming 10% increase in underlying interest rates	*Liability*	$ (44,353)	$ (33,049)
FV assuming 10% decrease in underlying interest rates	*Asset*	$ 4,914	$ 11,629

Cash flow hedges Treasury locks

At times, we may use treasury lock financial instruments to hedge the underlying U.S. treasury rates related to our anticipated issuances of debt. Gains or losses on the termination of such instruments are amortized to earnings using the effective interest method over the estimated term of the underlying fixed-rate debt. The following table summarizes changes in our treasury lock portfolio since December 31, 2006 (dollars in millions):

	Notional Amount	Cash Gain (Loss)
Treasury lock portfolio, December 31, 2006 (1)	$ 562.5	$ --
First quarter of 2007 additions to portfolio (1)	437.5	--
Second quarter of 2007 terminations (2)	(875.0)	42.3
Third quarter of 2007 additions to portfolio (3)	875.0	--
Third quarter of 2007 terminations (4)	(750.0)	6.6
Treasury lock portfolio, September 30, 2007 (5)	$ 250.0	$ 48.9

(1) EPO entered into these transactions related to its anticipated issuances of debt in 2007.

(2) Terminations relate to the issuance of the Junior Notes B ($500.0 million) and Senior Notes L ($375.0 million). Of the $42.3 million gain, $10.6 million relates to the Junior Notes B and the remainder to the Senior Notes L and its successor debt.

(3) EPO entered into these transactions related to its issuance of the Senior Notes L (including its successor debt) in August 2007 ($500.0 million) and anticipated issuance of debt during the first half of 2008 ($250.0 million)

(4) Terminations relate to the issuance of the Senior Notes L and its successor debt.

(5) The fair value of these financial instruments at September 30, 2007 was $2.9 million.

Since September 30, 2007, we have executed an additional $350.0 million in notional amount of treasury lock financial instruments.

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 hedge 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 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.

At September 30, 2007 and December 31, 2006, we had a limited number of commodity financial instruments in our portfolio, which primarily consisted of cash flow hedges. The fair value of our commodity financial instrument portfolio at September 30, 2007 and December 31, 2006 was a liability of $23.4 million and $3.2 million, respectively. During the three months ended September 30, 2007 and 2006, we recorded an expense of $10.5 million and an income of $7.8 million, respectively, related to our commodity financial instruments. During the nine months ended September 30, 2007 and 2006, we recorded an expense of $11.9 million and income $2.4 million, respectively, related to our commodity financial instruments.

We assess the risk of our commodity financial instrument portfolio using a sensitivity analysis model. The sensitivity analysis applied to this portfolio measures the potential income or loss (i.e., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at the date indicated within the following table. The following table shows the effect of hypothetical price movements on the estimated fair value (FV) of this portfolio at the dates presented (dollars in thousands):

		Commodity Financial Instrument Portfolio FV	
Scenario	**Resulting Classification**	**September 30, 2007**	**October 29, 2007**
FV assuming no change in underlying commodity prices	*Liability*	$ (23,392)	$ (21,765)
FV assuming 10% increase in underlying commodity prices	*Liability*	$ (10,839)	$ (12,724)
FV assuming 10% decrease in underlying commodity prices	*Liability*	$ (35,945)	$ (30,805)

Foreign Currency Hedging Program

We own an NGL marketing business located in Canada and have entered into construction agreements where payments are indexed to the Canadian dollar. 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. We use mark-to-market accounting for those foreign exchange contracts associated with our Canadian NGL marketing business. The duration of these contracts is typically one month. At September 30, 2007, $1.1 million of these exchange contracts were outstanding, all of which expired in October 2007. The foreign exchange contracts associated with our construction activities are accounted for using hedge accounting. At September 30, 2007, the fair value of these contracts was $2.9 million. These contracts settle through May 2008.

Item 4. ***Controls and Procedures*****.**

Our management, with the participation of the chief executive officer (CEO) and chief financial officer (CFO) of Enterprise Products GP, has evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on their evaluation, the CEO and CFO of Enterprise Products GP have concluded that our disclosure controls and procedures (as defined in Rule 13a-15(e)) are effective at a reasonable assurance level.

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

Disclosure controls and procedures are designed to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, including to ensure that such information is accumulated and communicated to our management, including our CEO and CFO, as appropriate, to allow timely decisions regarding required disclosures. Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected.

The certifications of our general partner s CEO and CFO required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this quarterly report on Form 10-Q.

PART II. OTHER INFORMATION.

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

See Part I, Item 1, Financial Statements, Note 14, Commitments and Contingencies Litigation, of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report, which is incorporated herein by reference.

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

In general, there have been no significant changes in our risk factors since December 31, 2006 other than the risk factor noted below. For a detailed discussion of our risk factors, please read, Item 1A Risk Factors, in our annual report on Form 10-K for 2006.

Tax Risks to Common Unitholders

We have adopted certain methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The Internal Revenue Service (IRS) may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under this methodology, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions.

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

We did not repurchase any of our common units during the three and nine months ended September 30, 2007. As of September 30, 2007, we and our affiliates are authorized to repurchase up to 618,400 common units under the December 1998 common unit repurchase program.

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

None.

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

None.

Item 5. ***Other Information*****.**

None.

Item 6. ***Exhibits*****.**

Exhibit Number	Exhibit*
2.1	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
2.2	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).
2.3	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.4	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to

	Exhibit 2.1 to the Form 8-K filed April 21, 2004).
2.5	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).
3.1	Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 8, 2005 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 10, 2005).
3.2#	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated as of November 7, 2007.

3.3	Limited Liability Company Agreement of Enterprise Products Operating LLC dated as of June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed on August 8, 2007).
3.4	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.5	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.6#	Certificate of Limited Partnership of Enterprise Products Partners L.P.
4.1	Indenture dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.2	First Supplemental Indenture dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.3	Second Supplemental Indenture dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.4	Third Supplemental Indenture dated as of June 30, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed on August 8, 2007) .
4.5	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-1/A; File No. 333-52537, filed July 21, 1998).
4.6	$750 Million Multi-Year Revolving Credit Agreement dated as of August 25, 2004, among Enterprise Products Operating L.P., the Lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, Citibank, N.A. and JPMorgan Chase Bank, as Co-Syndication Agents, and Mizuho Corporate Bank, Ltd., SunTrust Bank and The Bank of Nova Scotia, as Co-Documentation Agents (incorporated by reference to Exhibit 4.1 to Form 8-K filed on August 30, 2004).
4.7	First Amendment dated October 5, 2005, to Multi-Year Revolving Credit Agreement dated as of August 25, 2004, among Enterprise Products Operating L.P., the Lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, Citibank, N.A. and JPMorgan Chase Bank, as CO-Syndication Agents, and Mizuho Corporate Bank, Ltd., SunTrust Bank and The Bank of Nova Scotia, as Co-Documentation Agents (incorporated by reference to Exhibit 4.3 to Form 8-K filed on October 7, 2005).
4.8	Second Amendment dated June 22, 2006, to Multi-Year Revolving Credit Agreement dated as of August 25, 2004 among Enterprise Products Operating L.P., the Lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, Citibank, N.A. and JPMorgan Chase Bank, as Co-Syndication Agents and Mizuho Corporate Bank, LTD., SunTrust Bank and The Bank of Nova Scotia, as Co-Documentation Agents (incorporated by reference to Exhibit 4.6 to Form 10-Q filed August 8, 2006).
4.9	Third Amendment dated January 5, 2007, to Multi-Year Revolving Credit Agreement dated as of August 25, 2004 among Enterprise Products Operating L.P., the Lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, Citibank, N.A. and JPMorgan Chase Bank, as Co-Syndication Agents and Mizuho Corporate Bank, LTD, SunTrust Bank and The Bank of Nova Scotia, as Co-Documentation Agents. (incorporated by reference to Exhibit 4.47 to Form 10-K filed February 28, 2006).
4.10	Fourth Amendment dated June 30, 2007, to Multi-Year Revolving Credit Agreement dated as of August 25, 2004 among Enterprise Products Operating LLC, the Lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, Citibank, N.A. and JPMorgan Chase Bank, as Co-Syndication Agents and Mizuho Corporate Bank, LTD, SunTrust Bank and The Bank of Nova Scotia, as Co-Documentation Agents (incorporated by reference to Exhibit 4.56 to Form 10-Q filed on August 8, 2007).

4.11	Guaranty Agreement dated as of August 25, 2004, by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent for the several lenders that are or become parties to the Credit Agreement included as Exhibit 4.6, above (incorporated by reference to Exhibit 4.2 to Form 8-K filed on August 30, 2004).
4.12	Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed on October 6, 2004).
4.13	First Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on October 6, 2004).
4.14	Second Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on October 6, 2004).
4.15	Third Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed on October 6, 2004).
4.16	Fourth Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed on October 6, 2004).
4.17	Fifth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on March 3, 2005).
4.18	Sixth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on March 3, 2005).
4.19	Seventh Supplemental Indenture dated as of June 1, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.46 to Form 10-Q filed November 4, 2005).
4.20	Eighth Supplemental Indenture dated as of July 18, 2006 to Indenture dated October 4, 2004 among Enterprise Products Operating L.P., as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to exhibit 4.2 to Form 8-K filed July 19, 2006).
4.21	Ninth Supplemental Indenture, dated as of May 24, 2007, by and among Enterprise Products Operating L.P., as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed by Enterprise Products Partners L.P. on May 24, 2007).
4.22	Tenth Supplemental Indenture, dated as of June 30, 2007, by and among Enterprise Products Operating LLC, as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.23	Eleventh Supplemental Indenture, dated as of September 4, 2007, by and among Enterprise Products Operating LLC, as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on September 5, 2007).
4.24	Global Note representing $350 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.25	Global Note representing $500 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 10-K filed March

	31, 2003).
4.26	Global Notes representing $450 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.27	Global Note representing $500 million principal amount of 4.000% Series B Senior Notes due 2007 with attached Guarantee (incorporated by reference to Exhibit 4.14 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.28	Global Note representing $500 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.29	Global Note representing $150 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.30	Global Note representing $350 million principal amount of 6.650% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.31	Global Note representing $500 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.27 to Form 10-K for the year ended December 31, 2004 filed on March 15, 2005).
4.32	Global Note representing $250,000,000 principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed on November 4, 2005).
4.33	Global Note representing $250,000,000 principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed on November 4, 2005).
4.34	Global Note representing $500,000,000 principal amount of 4.95% Senior Notes due 2010 with attached Guarantee (incorporated by reference to Exhibit 4.47 to Form 10-Q filed November 4, 2005).
4.35	Amended and Restated Credit Agreement dated as of June 29, 2005, among Cameron Highway Oil Pipeline Company, the Lenders party thereto, and SunTrust Bank, as Administrative Agent and Collateral Agent (incorporated by reference to Exhibit 4.1 to Form 8-K filed on July 1, 2005).
4.36	Form of Junior Note, including Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K file July 19, 2006).
4.37	Purchase Agreement, dated as of July 12, 2006 between Cerrito Gathering Company, Ltd., Cerrito Gas Marketing, Ltd., Encinal Gathering, Ltd., as Sellers, Lewis Energy Group, L.P. as Guarantor, and Enterprise Products Partners L.P., as buyer (incorporated by reference to Exhibit 4.6 to Form 10-Q filed August 8, 2006).
4.38#	Global Note representing $800,000,000 principal amount of 6.30% Senior Notes due 2017 with attached Guarantee.
10.1#***	Enterprise Products 1998 Long-Term Incentive Plan, amended and restated as of November 9 2007.
10.2#***	Form of Option Grant Award under Enterprise Products 1998 Long-Term Incentive Plan.
10.3#***	Form of Restricted Unit Grant under the Enterprise Products 1998 Long-Term Incentive Plan.
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the September 30, 2007 quarterly report on Form 10-Q.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P. for the September 30, 2007 quarterly report on Form 10-Q.
32.1#	Section 1350 certification of Michael A. Creel for the September 30, 2007 quarterly report on Form 10-Q.
32.2#	Section 1350 certification of W. Randall Fowler for the September 30, 2007 quarterly report on Form 10-Q.

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file number for Enterprise Products Partners L.P. is

*** Identifies management contract and compensatory plan arrangement.

Filed with this report.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this quarterly report on Form 10-Q to be signed on its behalf by the undersigned thereunto duly authorized, in the City of Houston, State of Texas on November 9, 2007.

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

By: Enterprise Products GP, LLC,
as General Partner

By: ___/s/ Michael J. Knesek____________________
Name: Michael J. Knesek
Title: Senior Vice President, Controller
and Principal Accounting Officer
of the general partner