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, 2006

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 filero Non-accelerated filero

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 431,828,217 common units of Enterprise Products Partners L.P. outstanding at November 1, 2006. These common units trade on the New York Stock Exchange under the ticker symbol “EPD.”

ENTERPRISE PRODUCTS PARTNERS L.P.

TABLE OF CONTENTS

		Page No.
	PART I. FINANCIAL INFORMATION.	
Item 1.	**Financial Statements.**	
	Unaudited Condensed Consolidated Balance Sheets	2
	Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income	3
	Unaudited Condensed Statements of Consolidated Cash Flows	4
	Unaudited Condensed Statements of Consolidated Partners' Equity	5
	Notes to Unaudited Condensed Consolidated Financial Statements:	
	1. Partnership Organization and Basis of Financial Statement Presentation	6
	2. General Accounting Policies and Related Matters	7
	3. Accounting for Equity Awards	10
	4. Financial Instruments	13
	5. Inventories	14
	6. Property, Plant and Equipment	15
	7. Investments in and Advances to Unconsolidated Affiliates	17
	8. Business Combinations	19
	9. Intangible Assets and Goodwill	21
	10. Debt Obligations	23
	11. Partners' Equity	26
	12. Business Segments	29
	13. Related Party Transactions	33
	14. Earnings per Unit	36
	15. Commitments and Contingencies	37
	16. Significant Risks and Uncertainties – Weather-Related Risks	39
	17. Supplemental Cash Flow Information	41
	18. Condensed Financial Information of Operating Partnership	42
	19. Subsequent Events	43
Item 2.	**Management's Discussion and Analysis of Financial Condition and Results of Operations.**	45
Item 3.	**Quantitative and Qualitative Disclosures about Market Risk.**	77
Item 4.	**Controls and Procedures.**	79
	PART II. OTHER INFORMATION.	
Item 1.	**Legal Proceedings.**	79
Item 1A.	**Risk Factors.**	79
Item 2.	**Unregistered Sales of Equity Securities and Use of Proceeds.**	80
Item 3.	**Defaults upon Senior Securities.**	80
Item 4.	**Submission of Matters to a Vote of Security Holders.**	80
Item 5.	**Other Information.**	80
Item 6.	**Exhibits.**	80
Signatures		83

PART I. FINANCIAL INFORMATION.

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

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

ASSETS	September 30, 2006	December 31, 2005
Current assets		
Cash and cash equivalents	$ 117,400	$ 42,098
Restricted cash	21,155	14,952
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $19,368 at September 30, 2006 and $25,849 at December 31, 2005	1,356,778	1,448,026
Accounts receivable - related parties	25,678	6,557
Inventories	462,278	339,606
Prepaid and other current assets	171,469	120,208
Total current assets	2,154,758	1,971,447
Property, plant and equipment, net	9,401,669	8,689,024
Investments in and advances to unconsolidated affiliates	540,186	471,921
Intangible assets, net of accumulated amortization of $228,676 at September 30, 2006 and $163,121 at December 31, 2005	1,018,695	913,626
Goodwill	591,497	494,033
Deferred tax asset	3,054	3,606
Other assets	47,170	47,359
Total assets	$ 13,757,029	$ 12,591,016
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities		
Accounts payable - trade	$ 276,086	$ 265,699
Accounts payable - related parties	27,069	23,367
Accrued gas payables	1,436,504	1,372,837
Accrued expenses	29,477	30,294
Accrued interest	80,528	71,193
Other current liabilities	230,737	126,881
Total current liabilities	2,080,401	1,890,271
Long-term debt	4,884,261	4,833,781
Other long-term liabilities	102,609	84,486
Minority interest	126,244	103,169
Commitments and contingencies		
Partners' equity		
Limited partners		
Common units (430,776,555 units outstanding at September 30, 2006 and 389,109,564 units outstanding at December 31, 2005)	6,404,004	5,542,700
Restricted common units (1,051,662 units outstanding at September 30, 2006 and 751,604 units outstanding at December 31, 2005)	7,869	18,638
General partner	130,847	113,496
Accumulated other comprehensive income	20,794	19,072
Deferred compensation		(14,597)
Total partners' equity	6,563,514	5,679,309
Total liabilities and partners' equity	$ 13,757,029	$ 12,591,016

See Notes to Unaudited Condensed Consolidated Financial Statements

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
REVENUES				
Third parties	$ 3,740,162	$ 3,130,327	$ 10,304,580	$ 8,218,476
Related parties	132,363	118,964	335,872	258,105
Total	3,872,525	3,249,291	10,640,452	8,476,581
COST AND EXPENSES				
Operating costs and expenses				
Third parties	3,501,690	2,967,579	9,691,486	7,748,068
Related parties	83,093	77,766	263,745	211,054
Total operating costs and expenses	3,584,783	3,045,345	9,955,231	7,959,122
General and administrative costs				
Third parties	5,095	4,612	13,232	18,127
Related parties	10,728	8,640	32,566	28,528
Total general and administrative costs	15,823	13,252	45,798	46,655
Total costs and expenses	3,600,606	3,058,597	10,001,029	8,005,777
EQUITY IN INCOME OF UNCONSOLIDATED AFFILIATES	2,265	3,703	14,306	14,563
OPERATING INCOME	274,184	194,397	653,729	485,367
OTHER INCOME (EXPENSE)				
Interest expense	(62,793)	(60,538)	(177,203)	(170,697)
Other, net	2,136	1,394	7,498	3,558
Other expense	(60,657)	(59,144)	(169,705)	(167,139)
INCOME BEFORE PROVISION FOR INCOME TAXES, MINORITY INTEREST AND CHANGE IN ACCOUNTING PRINCIPLE	213,527	135,253	484,024	318,228
Provision for income taxes	(3,285)	(3,223)	(12,449)	(3,958)
INCOME BEFORE MINORITY INTEREST AND CHANGE IN ACCOUNTING PRINCIPLE	210,242	132,030	471,575	314,270
Minority interest	(1,940)	(861)	(4,676)	(3,186)
INCOME BEFORE CHANGE IN ACCOUNTING PRINCIPLE	208,302	131,169	466,899	311,084
Cumulative effect of change in accounting principle (see Note 3)			1,475	
NET INCOME	$ 208,302	$ 131,169	$ 468,374	$ 311,084
Cash flow financing hedges (see Note 4)	(1,638)			
Amortization of cash flow financing hedges	(1,065)	(1,017)	(3,158)	(3,018)
Change in fair value of commodity hedges	12,580	84	4,880	(1,350)
COMPREHENSIVE INCOME	$ 218,179	$ 130,236	$ 470,096	$ 306,716
ALLOCATION OF NET INCOME:				
Limited partners' interest in net income	$ 182,198	$ 112,126	$ 397,759	$ 259,889
General partner interest in net income	$ 26,104	$ 19,043	$ 70,615	$ 51,195
EARNINGS PER UNIT: (see Note 14)				
Basic income per unit before change in accounting principle	$ 0.43	$ 0.29	$ 0.97	$ 0.69
Basic income per unit	$ 0.43	$ 0.29	$ 0.97	$ 0.69
Diluted income per unit before change in accounting principle	$ 0.43	$ 0.29	$ 0.97	$ 0.69
Diluted income per unit	$ 0.43	$ 0.29	$ 0.97	$ 0.69

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,	
	2006	**2005**
OPERATING ACTIVITIES		
Net income	$ 468,374	$ 311,084
Adjustments to reconcile net income to cash flows provided from operating activities:		
Depreciation, amortization and accretion in operating costs and expenses	325,180	304,041
Depreciation and amortization in general and administrative costs	5,482	5,024
Amortization in interest expense	641	(116)
Equity in income of unconsolidated affiliates	(14,306)	(14,563)
Distributions received from unconsolidated affiliates	27,085	47,388
Cumulative effect of change in accounting principle	(1,475)	
Operating lease expense paid by EPCO, Inc.	1,582	1,584
Minority interest	4,676	3,186
Gain on sale of assets	(3,401)	(4,742)
Deferred income tax expense	12,378	5,827
Changes in fair market value of financial instruments	(41)	122
Net effect of changes in operating accounts (see Note 17)	159,849	(314,202)
Net cash provided from operating activities	986,024	344,633
INVESTING ACTIVITIES		
Capital expenditures	(1,040,341)	(627,913)
Contributions in aid of construction costs	63,670	40,368
Proceeds from sale of assets	3,043	43,220
Decrease (increase) in restricted cash	(6,203)	19,263
Cash used for business combinations	(144,973)	(325,080)
Acquisition of intangible asset		(1,750)
Investments in unconsolidated affiliates	(100,312)	(80,833)
Advances from unconsolidated affiliates	7,878	3,361
Return of investment of unconsolidated affiliate		47,500
Cash used in investing activities	(1,217,238)	(881,864)
FINANCING ACTIVITIES		
Borrowings under debt agreements	2,648,285	3,387,345
Repayments of debt	(2,587,000)	(2,865,007)
Debt issuance costs		(8,380)
Distributions paid to partners	(616,261)	(528,961)
Distributions paid to minority interests	(4,643)	(5,492)
Contributions from minority interests	23,091	28,486
Contribution from general partner related to issuance of restricted units		160
Net proceeds from issuance of common units	843,044	537,212
Cash provided by financing activities	306,516	545,363
NET CHANGE IN CASH AND CASH EQUIVALENTS	75,302	8,132
CASH AND CASH EQUIVALENTS, JANUARY 1	42,098	24,556
CASH AND CASH EQUIVALENTS, SEPTEMBER 30	$ 117,400	$ 32,688

See Notes to Unaudited Condensed Consolidated Financial Statements

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

	Limited Partners	General Partner	Deferred Compensation	Accumulated Other Comprehensive Income	Total
Balance, December 31, 2005	$ 5,561,338	$ 113,496	$ (14,597)	$ 19,072	$ 5,679,309
Net income	397,759	70,615			468,374
Operating leases paid by EPCO, Inc.	1,551	31			1,582
Cash distributions to partners	(540,989)	(73,540)			(614,529)
Unit option reimbursements to EPCO, Inc.	(1,697)	(35)			(1,732)
Net proceeds from sales of common units	818,520	16,691			835,211
Common units issued to Lewis in connection with Encinal acquisition	181,112	3,705			184,817
Proceeds from exercise of unit options	4,044	83			4,127
Change in accounting method for equity awards (see Note 3)	(15,814)	(312)	14,597		(1,529)
Amortization of equity awards	6,049	113			6,162
Change in fair value of commodity hedges				4,880	4,880
Interest rate hedging financial instruments recorded as cash flow hedges:					
- Amortization of gain as component of interest expense				(3,158)	(3,158)
Balance, September 30, 2006	$ 6,411,873	$ 130,847	$ -	$ 20,794	$ 6,563,514

See Notes to Unaudited Condensed Consolidated Financial Statements

1. Partnership Organization and Basis of Financial Statement Presentation

Partnership Organization and Formation

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." Unless the context requires otherwise, references to "we," "us," "our," or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO, Inc. ("EPCO"). We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating L.P. (our "Operating Partnership"). 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 and under common control of Dan L. Duncan, the Chairman and controlling shareholder of EPCO.

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 the general partner of TEPPCO, which is wholly owned by a private company subsidiary of EPCO.

On November 2, 2006, a newly formed and wholly owned subsidiary of ours, Duncan Energy Partners L.P. ("Duncan Energy Partners"), filed its initial registration statement for a proposed public offering of its common units. Duncan Energy Partners will own interests in certain of our midstream energy businesses. For additional information regarding this subsequent event, please read Note 19.

Basis of Presentation of Consolidated Financial Statements

Our results of operations for the three and nine months ended September 30, 2006 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, 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 the Operating Partnership level in our consolidated financial statements. We act as guarantor of certain of our Operating Partnership's debt obligations. See Note 18 for condensed consolidated financial information of our Operating Partnership.

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 our 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 generally accepted accounting principles 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" or "Commission"). These unaudited financial statements should be read in conjunction with our annual report on Form 10-K for the year ended December 31, 2005 (Commission File No. 1-14323).

2. General Accounting Policies and Related Matters

Consolidation policy

We evaluate our financial interests in business enterprises to determine if they represent variable interest entities requiring consolidation. 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 consolidate majority-owned subsidiaries in which we possess a controlling financial interest through a direct or indirect ownership of a majority voting interest in the subsidiary.

Investments in which we own 3% to 50% and exercise significant influence over operating and financial policies are accounted for using the equity method. If the investee is organized as a limited liability company and maintains separate ownership accounts for its members, we account for our investment using the equity method if our ownership interest is between 3% and 50%. For all other types of investees, we apply the equity method of accounting if our ownership interest is between 20% and 50%. 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 investee does not provide us with either control or significant influence over the investee, we account for the investment using the cost method.

Use of estimates

In accordance with GAAP, we use estimates and assumptions that affect the 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 each reporting period. Our actual results could differ from these estimates.

New accounting pronouncements

Emerging Issues Task Force ("EITF") 04-13, "Accounting for Purchases and Sale of Inventory With the Same Counterparty." This accounting guidance requires that two or more inventory transactions with the same counterparty should be viewed as a single nonmonetary transaction, if the transactions were entered into in contemplation of one another. Exchanges of inventory between entities in the same line of business should be accounted for at fair value or recorded at carrying amounts, depending on the classification of such inventory. This guidance was effective April 1, 2006, and our adoption of this guidance had no impact on our financial position, results of operations or cash flows.

EITF 06-3, "How Taxes Collected From Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)." This accounting guidance requires companies to disclose their policy regarding the presentation of tax receipts on the face of their income statements. This guidance specifically applies to taxes imposed by governmental authorities on revenue-producing transactions between sellers and customers (gross receipts taxes are excluded). This guidance is effective January 1, 2007. As a matter of policy, we report such taxes on a net basis.

Financial Accounting Standards Board Interpretation ("FIN") No. 48, "Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS 109, Accounting for Income Taxes." FIN 48 provides that tax effects of an uncertain tax position should be recognized in a company's financial statements if the position taken by the entity is more likely than not sustainable, if it were to be examined by an appropriate taxing authority, based on technical merit. After determining a tax position meets such criteria, the amount of benefit to be recognized should be the largest amount of benefit that has more than a 50 percent chance of being realized upon settlement. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006. We are currently assessing the impact, if any, the adoption of FIN 48 will have on our statements of financial position, results of operation and cash flows.

Statement of Financial Accounting Standards ("SFAS") 155, *"Accounting for Certain Hybrid Financial Instruments."* This accounting standard amends SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, amends SFAS 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, and resolves issues addressed in Statement 133 Implementation Issue D1, *Application of Statement 133 to Beneficial Interests to Securitized Financial Assets*. A hybrid financial instrument is one that embodies both an embedded derivative and a host contract. For certain hybrid financial instruments, SFAS 133 requires an embedded derivative instrument be separated from the host contract and accounted for as a separate derivative instrument. SFAS 155 amends SFAS 133 to provide a fair value measurement alternative for certain hybrid financial instruments that contain an embedded derivative that would otherwise be recognized as a derivative separately from the host contract. For hybrid financial instruments within its scope, SFAS 155 allows the holder of the instrument to make a one-time, irrevocable election to initially and subsequently measure the instrument in its entirety at fair value instead of separately accounting for the embedded derivative and host contract. We are evaluating the effect of this recent guidance, which is effective January 1, 2007 for our partnership.

SFAS 157, *"Fair Value Measurements."* This accounting standard defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, 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. The statement 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 December 15, 2007 and we will be required to adopt SFAS 157 as of January 1, 2008. We are currently evaluating the impact of adopting SFAS 157 on our financial position, results of operations, and cash flows.

SFAS 158, *"Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)."* This accounting standard requires an employer to recognize the over-funded or under-funded status of its defined benefit pension and other postretirement plans as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. In addition, SFAS 158 eliminates the use of a measurement date that is different than the date of the employer's year-end financial statements. SFAS 158 requires an employer to disclose in the notes to financial statements additional information about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition asset or obligation. Under SFAS 158, we will be required to recognize the funded status of our defined benefit pension and postretirement plans and to provide the required disclosures commencing as of December 31, 2006. We do not believe the adoption of SFAS 158 will have a material effect on our financial position, results of operations, and cash flows. For additional information regarding our accounting for employee benefit plans, please see "Accounting for employee benefit plans" in this Note 2.

Staff Accounting Bulletin ("SAB") No. 108, *"Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements."* SAB 108 addresses how the effects of prior-year uncorrected misstatements should be considered when quantifying misstatements in current-year financial statements. The SAB requires registrants to quantify misstatements using both the balance-sheet and income-statement approaches and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. When the effect of initial adoption is determined to be material, SAB 108 allows registrants to record the effect as a cumulative-effect adjustment to beginning-of-year retained earnings. The requirements are effective for annual financial statements covering the first fiscal year ending after November 15, 2006. Additionally, the nature and amount of each individual error being corrected through the cumulative-effect adjustment, when and how each error arose, and the fact that the errors had previously been considered immaterial is required to be disclosed. We are required to adopt SAB 108 for our current fiscal year ending December 31, 2006. We do not expect the adoption of SAB 108 to have a material impact on our financial statements.

Change in accounting principle

In January 2006, we adopted the provisions of 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. For additional information regarding our adoption of SFAS 123(R), see Note 3.

Accounting for employee benefit plans

Dixie Pipeline Company ("Dixie"), a consolidated subsidiary, directly employs the personnel operating its pipeline system. 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, 2006 and 2005. During each of the nine month periods ended September 30, 2006 and 2005, Dixie contributed $0.2 million to its company-sponsored defined contribution plan.

Pension and postretirement benefit plans. Dixie's net pension benefit costs were $0.2 million for each of the three month periods ended September 30, 2006 and 2005. For the nine months ended September 30, 2006 and 2005, Dixie's net pension benefit costs were $0.5 million and $0.4 million, respectively. Dixie's net postretirement benefit costs were $0.1 million for each of the three month periods ended September 30, 2006 and 2005. For the nine months ended September 30, 2006 and 2005, Dixie's net postretirement benefit costs were $0.2 million and $0.1 million, respectively. During the remainder of 2006, Dixie expects to contribute approximately $0.1 million to its postretirement benefit plan and approximately $1 million to its pension plan.

Provision for income taxes

Prior to the second quarter of 2006, our provision for income taxes related to federal income tax and state franchise and income tax obligations of Seminole and Dixie, which are both corporations and represented our only consolidated subsidiaries that were historically subject to such income taxes. In May 2006, the State of Texas enacted a new business tax (the "Texas Margin Tax") that replaced the existing state franchise tax. In general, legal entities that conduct business in Texas are subject to the Texas Margin Tax. Limited partnerships, limited liability companies, corporations and limited liability partnerships are examples of the types of entities that are subject to the Texas Margin Tax. As a result of the change in tax law, our tax status in the State of Texas will change from non-taxable to taxable. The tax is considered an income tax for purposes of adjustments to deferred tax liability as the tax is determined by applying a tax rate to a base that considers both revenues and expenses. The Texas Margin Tax becomes effective for margin tax reports due on or after January 1, 2008. The Texas Margin Tax due in 2008 will be based on revenues earned during the 2007 fiscal year.

The Texas Margin Tax is assessed at 1% of Texas-sourced taxable margin. The taxable margin is the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. Our deferred tax liability, which is a component of other long-term liabilities on our consolidated balance sheets, reflects the net tax effects of temporary differences related to items such as property, plant and equipment; therefore, the deferred tax liability is noncurrent. We recorded an estimated net deferred tax liability of approximately $6.6 million for the Texas Margin Tax. The offsetting net charge of $6.6 million is shown on our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income as a component of provision for income taxes for the nine months ended September 30, 2006.

3. Accounting for Equity Awards

Effective January 1, 2006, we adopted SFAS 123(R) to account for equity awards. Prior to our adoption of SFAS 123(R), we accounted for our equity awards using the intrinsic value method described in Accounting Principles Board Opinion ("APB") 25, "*Accounting for Stock Issued to Employees.*" SFAS 123(R) requires us to recognize compensation expense related to our equity awards based on the fair value of the award at the grant date. The fair value of an equity award is estimated using the Black-Scholes option pricing model. Under SFAS 123(R), the fair value of an award is amortized to earnings on a straight-line basis over the requisite service or vesting period.

Upon our adoption of SFAS 123(R), we recognized, as a benefit, a cumulative effect of a change in accounting principle of $1.5 million based on SFAS 123(R)'s requirement to recognize compensation expense based upon the grant date fair value of an equity award and the application of an estimated forfeiture rate to unvested awards. In addition, previously recognized deferred compensation expense of $14.6 million related to nonvested (or "restricted") common units was reversed on January 1, 2006.

Prior to our adoption of SFAS 123(R), we did not recognize any compensation expense related to unit options; however, compensation expense was recognized in connection with awards granted by EPE Unit L.P. (the "Employee Partnership") and the issuance of nonvested units. The effects of applying SFAS 123(R) during the three and nine months ended September 30, 2006 did not have a material effect on our net income or basic and diluted earnings per unit.

Since we adopted SFAS 123(R) using the modified prospective method, we have not restated the financial statements of prior periods to reflect this new standard. The following table shows the pro forma effects on our earnings for the three and nine months ended September 30, 2005 as if the fair value method of SFAS 123, "*Accounting for Stock-Based Compensation*" had been used instead of the intrinsic-value method of APB 25. The only equity awards outstanding during the three and nine months ended September 30, 2005 were unit options and nonvested units.

	For the Three Months Ended September 30, 2005	For the Nine Months Ended September 30, 2005
Reported net income	$ 131,169	$ 311,084
Additional unit option-based compensation expense estimated using fair value-based method	(177)	(531)
Pro forma net income	$ 130,992	$ 310,553
Basic and diluted earnings per unit:		
As reported	$ 0.29	$ 0.69
Pro forma	$ 0.29	$ 0.68

Unit options

Under EPCO's 1998 Long-Term Incentive Plan (the "1998 Plan"), non-qualified incentive options to purchase a fixed number of our common units may be granted to EPCO's key employees who perform management, administrative or operational functions for us. When issued, the exercise price of each option grant is equivalent to the market price of the underlying equity on the date of grant. In general, options granted under the 1998 Plan have a vesting period of four years and remain exercisable for ten years from the date of grant.

In order to fund its obligations under the 1998 Plan, EPCO purchases common units at fair value either in the open market or directly from us. When employees exercise unit options, we reimburse EPCO for our allocable share of the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model, which incorporates various assumptions including (i) an expected life of the options of seven years, (ii) risk-free interest rates ranging from 3.1% to 6.4%, (iii) an expected distribution yield on our common units ranging from 5.3% to 10%, and (iv) expected unit price volatility on our common units ranging from 20% to 30%. In general, our assumption of expected life represents the period of time that options are expected to be outstanding based on an analysis of historical option activity. Our selection of the risk-free interest rate is based on published yields for U.S. government securities with comparable terms. The expected distribution yield and unit price volatility for our units is estimated based on several factors, which include an analysis of our historical unit price volatility and distribution yield over a period equal to the expected life of the option.

The information in the following table shows unit option activity under the 1998 Plan.

	Number of Units	Weighted-average strike price	Weighted-average remaining contractual term (in years)	Aggregate Intrinsic Value (1)
Outstanding at December 31, 2005	2,082,000	$ 22.16		
Granted	590,000	$ 24.85		
Exercised	(155,000)	$ 15.14		
Forfeited	(45,000)	$ 24.28		
Outstanding at September 30, 2006	2,472,000	$ 23.20	7.79	$ 3,872
Exercisable at September 30, 2006	622,000	$ 20.53	5.24	$ 3,872

(1) Aggregate intrinsic value reflects fully vested unit options at September 30, 2006.

The total intrinsic value of unit options exercised during the three and nine months ended September 30, 2006 was $1.1 million and $1.7 million, respectively. We recognized $0.2 million and $0.5 million of compensation expense associated with unit options during the three and nine months ended September 30, 2006, respectively.

As of September 30, 2006, there was an estimated $1.7 million of total unrecognized compensation cost related to nonvested unit options granted under the 1998 Plan to EPCO employees who work on our behalf. That cost is expected to be recognized over a weighted-average period of 2.6 years.

During the nine months ended September 30, 2006, we received cash of $4 million from the exercise of unit options, and our option-related reimbursements to EPCO were $1.7 million.

Nonvested units

Under the 1998 Plan, we may issue nonvested (or “restricted”) common units to key employees of EPCO and directors of our general partner. The 1998 Plan provides for the issuance of 3,000,000 restricted common units, of which 1,956,433 remain authorized for issuance at September 30, 2006.

In general, our restricted unit awards allow recipients to acquire the underlying common units (at no cost to the recipient) once a defined vesting period expires, subject to certain forfeiture provisions. The restrictions on such nonvested units generally lapse four years from the date of grant. Compensation expense is recognized on a straight-line basis over the vesting period. The fair value of such restricted units is based on (i) the market price of the underlying common units on the date of grant and (ii) an allowance for forfeitures.

The following table summarizes information regarding our restricted units for the nine months ended September 30, 2006.

	Number of Units	Weighted-average grant date fair value
Restricted units at December 31, 2005	751,604	$ 24.49
Granted	410,400	$ 24.90
Vested	(39,711)	$ 23.91
Forfeited	(70,631)	$ 24.16
Restricted units at September 30, 2006	1,051,662	$ 24.70

The total fair value of restricted units that vested during the nine months ended September 30, 2006 was $1 million. During the three and nine months ended September 30, 2006, we recognized $0.8 million and $3.1 million of compensation expense, respectively, associated with nonvested units.

As of September 30, 2006, there was $11.7 million of total unrecognized compensation cost related to nonvested units issued to EPCO employees that work on our behalf. That cost is expected to be recognized over a weighted-average period of 2.9 years.

Employee Partnership

In connection with the initial public offering of Enterprise GP Holdings in August 2005, the Employee Partnership was formed to serve as an incentive arrangement for certain employees of EPCO through a "profits interest" in the Employee Partnership. At inception, the Employee Partnership used $51 million in contributions it received from an affiliate of EPCO (which was admitted as the Class A limited partner of the Employee Partnership as a result of such contribution) to purchase 1,821,428 units of Enterprise GP Holdings in August 2005. Certain EPCO employees, including substantially all of EPE Holdings' and Enterprise Products GP's executive officers other than Dan L. Duncan, were issued Class B limited partner interests without any capital contribution and admitted as Class B limited partners of the Employee Partnership.

As described in its partnership agreement, the Employee Partnership will be liquidated upon the earlier of (i) August 2010 or (ii) a change in control of Enterprise GP Holdings or its general partner, EPE Holdings. Upon liquidation of the Employee Partnership, units having a fair market value equal to the Class A limited partner's capital base will be distributed to the Class A limited partner, plus any Class A preferred return for the quarter in which liquidation occurs. Any remaining units will be distributed to the Class B limited partners as a residual profits interest in the Employee Partnership as an award.

Prior to our adoption of SFAS 123(R), the estimated value of the profits interest was accounted for in a manner similar to a stock appreciation right. Upon our adoption of SFAS 123(R), we began recognizing compensation expense based upon the estimated grant date fair value of the Class B partnership equity awards.

The fair value of the Class B partnership equity awards is estimated on the date of grant using the Black-Scholes option pricing model, which incorporates various assumptions including (i) an expected life of the awards ranging from five to four years, (ii) risk-free interest rates ranging from 4.1% to 4.8%, (iii) an expected distribution yield on units of Enterprise GP Holdings ranging from 3.0% to 3.7%, and (iv) an expected Enterprise GP Holdings unit price volatility ranging from 21.1% to 30.0%. In general, the methodology we followed to estimate the fair value of the Class B partnership equity awards is similar to that used to estimate the fair value of Enterprise Products Partners' unit options.

During the three and nine months ended September 30, 2006, we recognized $0.5 million and $1.6 million of compensation expense, respectively, associated with such profits interests. As of September 30, 2006, there was $9.9 million of total unrecognized compensation cost related to the profits interests, of which we estimate our allocable share to be $8.8 million. That cost is expected to be recognized on a straight-line basis through the third quarter of 2010.

4. Financial Instruments

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type 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 certain interest rates or commodity prices. 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 exposures by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt.

Fair value hedges – Interest rate swaps. As summarized in the following table, we had eleven interest rate swap agreements outstanding at September 30, 2006 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 8.89%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 7.43%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.6% to 6.14%	$600 million
Senior Notes K, 4.95% fixed rate, due June 2010	2	Aug. 2005 to June 2010	June 2010	4.95% to 5.73%	$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, 2006 and December 31, 2005, was a liability of $30.4 million and $19.2 million, respectively, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the three months ended September 30, 2006 and 2005 reflects a $1.9 million expense and a $2.3 million benefit from these swap agreements, respectively. For the nine months ended September 30, 2006 and 2005, interest expense reflects a $2.8 million expense and a $9.8 million benefit, respectively, from these swap agreements.

Cash flow hedges – Treasury Locks. During the second quarter of 2006, the Operating Partnership entered into a treasury lock transaction having a notional amount of $250 million. In addition, in July 2006, the Operating Partnership entered into an additional treasury lock transaction having a notional amount of $50 million. A treasury lock is a specialized agreement that fixes the price (or yield) on a specific treasury security for an established period of time. A treasury lock purchaser is protected from a rise in the yield of the underlying treasury security during the lock period. The Operating Partnership's purpose of entering into these transactions was to hedge the underlying U.S. treasury rate related to its anticipated issuance of subordinated debt during the second quarter of 2006. In July 2006, the Operating Partnership issued $300 million in principal amount of its Junior Notes A (see Note 10). Each of the treasury lock transactions was designated as a cash flow hedge under SFAS 133. In July 2006, the Operating Partnership elected to terminate these treasury lock transactions and recognized a minimal gain.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and 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.

The fair value of our commodity financial instrument portfolio at September 30, 2006 and December 31, 2005 was a benefit of $4.8 million and a liability of $0.1 million, respectively. During the three and nine months ended September 30, 2006, we recorded $7.8 million and $2.4 million of income related to our commodity financial instruments, respectively, which is included in operating costs and expenses on our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income. We recorded nominal amounts of earnings from our commodity financial instruments during the three and nine months ended September 30, 2005.

5. Inventories

The following table shows our inventory amounts at the dates indicated:

	September 30, 2006	December 31, 2005
Working inventory	$ 397,939	$ 279,237
Forward-sales inventory	64,339	60,369
Inventory	$ 462,278	$ 339,606

Our regular trade (or "working") inventory is comprised of inventories of natural gas, NGLs, and certain petrochemical products that are available for sale or used by us in the provision of services. Our forward sales inventory consists of segregated NGL and natural gas volumes dedicated to the fulfillment of forward-sales contracts. Both inventories are valued at the lower of average cost or market.

Costs and expenses, as shown on our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income, include cost of sales related to the sale of inventories. For the three months ended September 30, 2006 and 2005, such consolidated cost of sales amounts were $3.2 billion and $2.7 billion, respectively. We recorded $9 billion and $7.1 billion of such consolidated cost of sales amounts for the nine months ended September 30, 2006 and 2005, respectively.

Due to fluctuating commodity prices in the NGL, natural gas and petrochemical industry, we recognize lower of cost or market adjustments when the carrying values 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, 2006 and 2005, we recognized $5.7 million and $0.5 million, respectively, of lower of cost or market adjustments. We recorded $17.7 million and $17.5 million of such adjustments for the nine months ended September 30, 2006 and 2005, respectively.

6. Property, Plant and Equipment

The following table shows our property, plant and equipment and accumulated depreciation at the dates indicated:

	Estimated Useful Life in Years	September 30, 2006	December 31, 2005
Plants and pipelines (1)	3-35 (5)	$ 8,704,110	$ 8,209,580
Underground and other storage facilities (2)	5-35 (6)	574,641	549,923
Platforms and facilities (3)	23-31	161,880	161,807
Transportation equipment (4)	3-10	24,806	24,939
Land		39,624	38,757
Construction in progress		1,304,698	854,595
Total		10,809,759	9,839,601
Less accumulated depreciation		1,408,090	1,150,577
Property, plant and equipment, net		$ 9,401,669	$ 8,689,024

(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: 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: 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).

Depreciation expense for the three months ended September 30, 2006 and 2005 was $88.9 million and $81.8 million, respectively. We recorded $259.4 million and $239.9 million of depreciation expense for the nine months ended September 30, 2006 and 2005, respectively. Capitalized interest on our construction projects for the three months ended September 30, 2006 and 2005 was $15 million and $4.6 million, respectively. We recorded $36.6 million and $12.2 million of capitalized interest on our construction projects for the nine months ended September 30, 2006 and 2005, respectively. The increase in capitalized interest period-to-period is due to our capital spending program.

In March 2006, we paid $38.2 million to TEPPCO for its Pioneer natural gas processing plant located in Opal, Wyoming and certain natural gas processing rights related to production from the Jonah and Pinedale fields located in the Greater Green River Basin in Wyoming. After completing this asset purchase, we increased the capacity of the Pioneer natural gas processing plant at an additional cost of $21 million. This expansion was completed in July 2006 and enables us to process natural gas production from the Jonah and Pinedale fields that will be transported to our Wyoming facilities as a result of the contract rights we acquired from TEPPCO. Of the $38.2 million we paid TEPPCO to acquire the Pioneer facility, $37.8 million was allocated to the contract rights we acquired. See Note 9 for information regarding the intangible assets recorded in connection with this asset purchase.

In August 2006, we acquired a 223-mile pipeline from ExxonMobil Pipeline Company for $97.7 million in cash. This pipeline originates in Corpus Christi, Texas and extends to Pasadena, Texas. This pipeline segment will be expanded (the "Phase I expansion") to (i) connect with our Armstrong and Shoup NGL fractionation facilities through the construction of 45 miles of pipeline laterals; (ii) lease from TEPPCO a 10-mile interconnecting pipeline extending from Pasadena, Texas to Baytown, Texas; and (iii) purchase an additional 10-mile pipeline from TEPPCO that will connect the leased TEPPCO pipeline to Mont Belvieu, Texas. The purchase of the 10-mile segment from TEPPCO is estimated to cost $8 million and be completed during the fourth quarter of 2006. The primary term of the TEPPCO pipeline lease will expire in July 2007, and will continue on a month-to-month basis subject to customary termination provisions. Collectively, this 288-mile pipeline will be termed the South Texas NGL pipeline system. The South Texas NGL pipeline system is not in operation, but it is currently undergoing modifications, extensions and interconnections as described above to allow it to transport NGLs beginning in January 2007.

During 2007, we will construct an additional 21 miles of pipeline (the "Phase II upgrade") to replace (i) the 10-mile pipeline we will lease from TEPPCO and (ii) certain segments of the pipeline we acquired in August 2006 from ExxonMobil Pipeline Company. The Phase II upgrade is expected to provide a significant increase in pipeline capacity and be operational during the third quarter of 2007.

We estimate the cost of the Phase I expansion to be $37.7 million, which includes the $8 million we will pay TEPPCO to acquire its 10-mile Baytown to Mont Belvieu pipeline. We expect the Phase II upgrade to cost an additional $30.9 million.

The South Texas NGL pipeline system will be owned by our new subsidiary, South Texas NGL Pipelines, LLC. Please see Note 19 for a subsequent event involving this subsidiary.

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. Our investments in and advances to unconsolidated affiliates are grouped according to the business segment to which they relate. For a general discussion of our business segments, see Note 12. The following table shows our investments in and advances to unconsolidated affiliates at the dates indicated.

	Ownership Percentage at September 30, 2006	Investments in and advances to Unconsolidated Affiliates at September 30, 2006	Investments in and advances to Unconsolidated Affiliates at December 31, 2005
NGL Pipelines & Services:			
Venice Energy Services Company, LLC ("VESCO")	13.1%	$ 39,572	$ 39,689
K/D/S Promix LLC ("Promix")	50%	54,111	65,103
Baton Rouge Fractionators LLC ("BRF")	32.3%	25,332	25,584
Onshore Natural Gas Pipelines & Services:			
Jonah Gas Gathering Company ("Jonah") (1)	11% (2)	83,294	
Evangeline (3)	49.5%	3,907	3,151
Coyote Gas Treating, LLC ("Coyote") (4)	50%		1,493
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36%	64,852	62,918
Cameron Highway Oil Pipeline Company ("Cameron Highway")	50%	58,828	58,207
Deepwater Gateway, L.L.C. ("Deepwater Gateway")	50%	120,777	115,477
Neptune Pipeline Company, L.L.C. ("Neptune")	25.7%	59,867	68,085
Nemo Gathering Company, LLC ("Nemo")	33.9%	10,682	12,157
Petrochemical Services:			
Baton Rouge Propylene Concentrator, LLC ("BRPC")	30%	14,343	15,212
La Porte (5)	50%	4,621	4,845
Total		$ 540,186	$ 471,921

(1) In August 2006, we announced a 50/50 common control joint venture in which we and TEPPCO will be partners in Jonah. Jonah owns the Jonah Gas Gathering System located in the Greater Green River Basin of southwestern Wyoming. This 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 users. See Note 13 for additional information regarding the Jonah joint venture with TEPPCO.

(2) Upon completion of the Jonah Phase V expansion project in 2007 (see Note 13), we expect to own an approximate 20% equity interest in Jonah, with TEPPCO owning the remaining 80%. Our equity interest in Jonah at September 30, 2006 is approximately 11% based on capital contributions made by us through this date. 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.

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

(4) We sold our 50% interest in Coyote in August 2006 and recorded a net gain on the sale of $3.3 million.

(5) Refers to our ownership interests in La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively.

Equity method investments are evaluated for impairment when events or changes in circumstances indicate there is a loss in value of the investment which is an other than temporary decline. In the event we determine that the loss in value of an investment is other than a temporary decline, we would record a charge to earnings to adjust the carrying value to fair value.

Neptune owns the Manta Ray Offshore Gathering System ("Manta Ray") and Nautilus Pipeline System ("Nautilus"). Manta Ray gathers natural gas originating from producing fields located in the Green Canyon, Southern Green Canyon, Ship Shoal, South Timbalier and Ewing Bank areas of the Gulf of Mexico to numerous downstream pipelines, including the Nautilus pipeline. Nautilus connects our Manta Ray pipeline to our Neptune natural gas processing plant located in South Louisiana. Due to a recent decrease in throughput volumes on the Manta Ray and Nautilus pipelines, we evaluated our 25.7% investment in Neptune for impairment during the third quarter of 2006. The decrease in throughput volumes is primarily due to underperformance of certain fields, natural depletion and hurricane-related delays in starting new production. These factors contributed to significant delays in throughput volumes Neptune expects to receive. As a result, Neptune has experienced operating losses in recent periods.

At December 31, 2005, the carrying value of our investment in Neptune was $68.1 million, which included $10.9 million of excess cost related to its original acquisition in 2001. Our review of Neptune's estimated cash flows during the third quarter of 2006 indicated that the carrying value of our investment exceeded its fair value, which resulted in a non-cash impairment charge of $7.4 million. This loss is recorded as a component of "Equity in income of unconsolidated affiliates" in our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income for the three and nine months ended September 30, 2006. Equity earnings from our investment in Neptune are classified under our Offshore Pipelines & Services business segment. After recording this impairment charge, the carrying value of our investment in Neptune at September 30, 2006 was $59.9 million, which reflects $0.7 million in losses and $0.1 million of distributions we recorded during the first nine months of 2006.

Our investment in Neptune 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 Neptune included management estimates regarding natural gas reserves of producers served by the Neptune pipelines. If the assumptions underlying our fair value analysis change and expected cash flows are reduced, additional impairment charges may result.

On occasion, the price we pay to purchase an equity interest in a company exceeds the underlying book capital account we acquire. Such excess cost amounts are included within our investments in and advances to unconsolidated affiliates. At September 30, 2006, our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway and Nemo included excess cost amounts totaling $39.1 million, all of which was attributed to fair values in excess of the underlying carrying values of tangible assets at the time of our acquisition of interests in these entities. Amortization of such excess cost amounts was $0.5 million during each of the three month periods ended September 30, 2006 and 2005. For the nine months ended September 30, 2006 and 2005, amortization of such amounts was $1.6 million and $1.7 million, respectively.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
NGL Pipelines & Services	$ 1,422	$ 773	$ 4,864	$ 8,058
Onshore Natural Gas Pipelines & Services	794	604	2,300	1,866
Offshore Pipelines & Services (1)	(330)	2,321	6,373	4,221
Petrochemical Services	379	5	769	418
Total	$ 2,265	$ 3,703	$ 14,306	$ 14,563

(1) Equity earnings from Cameron Highway for the nine months ended September 30, 2005 were reduced by a charge of $11.5 million for costs associated with the refinancing of Cameron Highway's project debt in June 2005. The reduction in equity earnings from Cameron Highway for the nine months ended September 30, 2005, is offset by increases in equity earnings from investments we acquired in connection with the GulfTerra Merger. The 2006 amounts include the non-cash Neptune impairment charge of $7.4 million.

Summarized financial information of unconsolidated affiliates

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

	Summarized Income Statement Information for the Three Months Ended					
	September 30, 2006			September 30, 2005		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income	Net Income
NGL Pipelines & Services (1)	$ 63,086	$ (4,031)	$ (3,644)	$ 54,816	$ 5,267	$ 5,671
Onshore Natural Gas Pipelines & Services	82,924	2,091	1,441	96,809	633	1,216
Offshore Pipelines & Services	41,245	21,311	14,138	53,959	34,044	26,591
Petrochemical Services	5,029	1,527	1,560	3,782	281	298

(1) The decrease in earnings generated by the unconsolidated affiliates within our NGL Pipelines & Services segment is primarily attributable to losses incurred by VESCO due to the effects of Hurricane Katrina.

	Summarized Income Statement Information for the Nine Months Ended					
	September 30, 2006			September 30, 2005		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income	Net Income
NGL Pipelines & Services (1)	$ 143,592	$ (28,394)	$ (27,107)	$ 194,162	$ 33,100	$ 34,102
Onshore Natural Gas Pipelines & Services	242,647	6,796	4,355	232,217	6,835	3,539
Offshore Pipelines & Services (2)	112,495	52,407	30,622	121,610	67,840	25,026
Petrochemical Services	14,454	3,358	3,435	11,829	2,130	2,169

(1) The decrease in earnings generated by the unconsolidated affiliates within our NGL Pipelines & Services segment is primarily attributable to losses incurred by VESCO due to the effects of Hurricane Katrina.

(2) Earnings for Cameron Highway for the six months ended June 30, 2005 were reduced by a charge of $11.5 million for costs associated with the refinancing of Cameron Highway's project debt in June 2005.

8. Business Combination

Effective July 1, 2006, we acquired the Encinal and Canales natural gas gathering systems and related gathering and processing contracts and other amounts 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 $326.1 million, consisting of $145 million in cash and 7,115,844 of our common units.

Our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income for the three and nine months ended September 30, 2006 includes three months of results of operations from the Encinal business.

The Encinal and Canales gathering systems are located in South Texas and are connected to over 1,450 natural gas production wells tapped into the Olmos and Wilcox formations. The Encinal system consists of 452 miles of pipeline, which is comprised 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, volumes gathered by the Encinal and Canales systems are transported by our existing South Texas pipeline system and are processed by our South Texas natural gas processing plants.

As part of this transaction, we acquired long-term natural gas processing and gathering dedications from Lewis. First, these gathering systems will be supported by a life of reserves gathering and processing dedication of Lewis' natural gas production from the Olmos formation. Second, Lewis entered into a 10-year agreement with us for the transportation of natural gas treated at its Big Reef facility. This facility processes natural gas production from the southern portion of the Edwards Trend in South Texas. Third, Lewis entered into a 10-year gathering and processing agreement with us for rich gas developed below the Olmos formation.

The total consideration paid or granted for the Encinal acquisition is summarized in the following table:

Cash consideration, including third-party direct transaction costs	$ 144,973
Fair value of our 7,115,844 common units issued to Lewis	181,112
Total consideration	$ 326,085

In accordance with purchase accounting, the value of our common units issued to Lewis is based on the average closing price of such units immediately prior to and after the transaction was announced on July 12, 2006. The average closing price used was $25.45 per unit.

Purchase price allocation

This acquisition was accounted for under the purchase method of accounting and, accordingly, its cost has been allocated to the assets acquired and liabilities assumed based on estimated preliminary fair values. Such preliminary values have been developed using recognized business valuation techniques and are subject to change pending a final valuation report. We expect to finalize the purchase price allocation for this transaction during the third quarter of 2007.

Purchase price allocation:	
Assets acquired in business combination:	
Current assets	$ 218
Property, plant and equipment, net	100,310
Intangible assets	132,872
Total assets acquired	233,400
Liabilities assumed in business combination:	
Current liabilities	(2,149)
Other long-term liabilities	(108)
Total liabilities assumed	(2,257)
Total assets acquired less liabilities assumed	231,143
Total consideration given	326,085
Remaining Goodwill	$ 94,942

As a result of our preliminary purchase price allocation, we recorded $132.9 million of amortizable intangible assets. The remaining preliminary amount represents goodwill of $94.9 million, which management attributes to potential future benefits we may realize from our other South Texas processing and NGL businesses as a result of the Encinal acquisition. Specifically, the long-term dedication rights acquired in connection with the Encinal acquisition are expected to add value to our South Texas processing facilities and related NGL businesses due to increased volumes. For additional information regarding our intangible assets and goodwill, see Note 9.

Pro forma financial information

The following table presents selected unaudited pro forma financial information incorporating the historical results of the Encinal and Canales operations. The effective closing date of our purchase of the Encinal business was July 1, 2006. As a result, our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income for the three and nine months ended September 30, 2006 include three months of results of operations of this acquired business.

Our unaudited pro forma financial information reflects transactions that are factually supportable and exclude amounts that may or may not be realized from operating synergies or potential future business opportunities resulting from the business combination.

The following pro forma information has been prepared as if the acquisition had been completed on January 1, 2005 rather than the actual closing date. The pro forma information is based upon data currently available and includes certain estimates and assumptions made by management. As a result, this pro forma information is not necessarily indicative of our financial results had the transaction actually occurred on this date. Likewise, the following unaudited pro forma financial information is not necessarily indicative of our future financial results.

	Six Months Ended June 30, 2006	Year Ended December 31, 2005
Pro forma earnings data:		
Revenues	$ 10,714,216	$ 12,408,112
Costs and expenses	$ 10,076,252	$ 11,758,425
Operating income	$ 652,270	$ 664,235
Income before extraordinary items	$ 465,321	$ 417,534
Net income	$ 465,321	$ 417,534
Basic earnings per unit, net of general partner interest:		
As reported basic units outstanding	408,469	381,857
Pro forma basic units outstanding	415,585	388,973
As reported basic net income per unit	$ 0.97	$ 0.91
Pro forma basic net income per unit	$ 0.95	$ 0.89
Diluted earnings per unit, net of general partner interest:		
As reported pro forma units outstanding	408,763	382,963
Pro forma diluted units outstanding	415,879	390,079
As reported diluted net income per unit	$ 0.97	$ 0.91
Pro forma diluted net income per unit	$ 0.95	$ 0.89

9. Intangible Assets and Goodwill

Identifiable intangible assets

As a result of asset purchases and business combinations during the nine months ended September 30, 2006, we recorded an additional $170.7 million of intangible assets. The following table summarizes our intangible assets by business segment at the dates indicated. Our intangible assets primarily consist of values we assigned to contracts and customer relationships.

	At September 30, 2006			At December 31, 2005	
Business Segment	Gross Value	Accum. Amort.	Carrying Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services (1,2)	$ 520,134	$ (101,459)	$ 418,675	$ (79,485)	$ 275,778
Onshore Natural Gas Pipelines & Services(2)	463,551	(69,136)	394,415	(43,955)	413,843
Offshore Pipelines & Services	207,012	(49,385)	157,627	(32,480)	174,532
Petrochemical Services	56,674	(8,696)	47,978	(7,201)	49,473
Total	$ 1,247,371	$ (228,676)	$ 1,018,695	$ (163,121)	$ 913,626

(1) In March 2006, we recorded an additional $37.8 million of contract-based intangible assets in connection with our acquisition of the Pioneer natural gas processing plant and associated natural gas processing rights. See Note 6 for additional information regarding this asset purchase.
(2) In July 2006, we recorded an additional $132.9 million of customer relationship intangible assets in connection with our acquisition of the Encinal midstream energy business from Lewis. The amortization period for these intangible assets is 20 years. See Note 8 for additional information regarding this business combination.

The $37.8 million of intangible assets we acquired in connection with our purchase of the Pioneer natural gas processing plant (see Note 6) represent our contractual rights to process natural gas produced from the Jonah and Pinedale fields located in the Greater Green River Basin in Wyoming. The value we assigned to these processing rights is recorded in our NGL Pipelines & Services segment and will be amortized to earnings using methods that closely resemble the pattern in which we estimate the depletion of the underlying natural gas resource basins. Our estimate of the remaining useful life of each resource basin is predicated on a number of factors, including third-party reserve estimates, the economic viability of production and exploration activities in the basin and other industry-related factors.

The $132.9 million of intangible assets we acquired in connection with the Encinal acquisition (see Note 8) represents the value we assigned to customer relationships, particularly the long-term relationship we now have with Lewis through natural gas processing and gathering arrangements. We recorded $127.1 million in our NGL Pipelines & Services segment associated with processing arrangements and $5.8 million in our Onshore Natural Gas Pipelines & Services segment associated with gathering arrangements. Customer relationships, as used in this context, represent the estimated economic value attributable to (i) contractual arrangements in existence at the time of the acquisition plus (ii) projected cash flows from the anticipated future renewal of such arrangements due to the relationship we have with such customer. These intangible assets will be amortized to earnings in a manner similar to that described in the previous paragraph.

The following table shows amortization expense by segment associated with our intangible assets for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
NGL Pipelines & Services	$ 9,309	$ 6,555	$ 21,974	$ 20,027
Onshore Natural Gas Pipelines & Services	8,375	8,690	25,181	26,510
Offshore Pipelines & Services	5,438	6,261	16,905	19,471
Petrochemical Services	499	498	1,495	1,495
Total	$ 23,621	$ 22,004	$ 65,555	$ 67,503

For the remainder of 2006, amortization expense associated with our intangible assets is currently estimated at $23.2 million. Based on information available, we estimate that the additional amortization expense associated with the intangible assets we acquired during the first nine months of 2006 will be $12.7 million in 2007, $13.9 million in 2008, $13 million in 2009, $12.1 million in 2010 and $11.3 million in 2011.

Goodwill

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

	September 30, 2006	December 31, 2005
NGL Pipelines & Services	$ 152,444	$ 54,960
Onshore Natural Gas Pipelines & Services	282,977	282,997
Offshore Pipelines & Services	82,386	82,386
Petrochemical Services	73,690	73,690
Totals	$ 591,497	$ 494,033

In August 2006, we recorded $94.9 million of goodwill in connection with our preliminary purchase price allocation for the Encinal acquisition. Management attributes this goodwill amount to potential future benefits we may realize from our other South Texas processing and NGL businesses as a result of acquiring the Encinal business. Specifically, our acquisition of the long-term dedication rights associated with the Encinal business is expected to add value to our South Texas processing facilities and related NGL businesses due to increased volumes. The Encinal goodwill is recorded as part of the NGL

Pipelines & Services business segment due to management's belief that such future benefits will accrue to businesses classified within this segment.

The remainder of our goodwill is associated with previous acquisitions, principally the $387.1 million recorded in connection with the merger of GulfTerra Energy Partners, L.P. with a wholly owned subsidiary of ours in September 2004.

10. Debt Obligations

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

	September 30, 2006	December 31, 2005
Operating Partnership debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due October 2011 (1)		$ 490,000
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	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
Dixie Revolving Credit Facility, variable rate, due June 2010 (2)	10,000	17,000
Debt obligations assumed from GulfTerra	5,068	5,068
Total principal amount of senior debt obligations	4,369,068	4,866,068
Junior Notes A, due August 2066	550,000	
Total principal amount of senior and junior debt obligations	4,919,068	4,866,068
Other, including unamortized discounts and premiums and changes in fair value (3)	(34,807)	(32,287)
Long-term debt	$ 4,884,261	$ 4,833,781
Standby letters of credit outstanding	$ 53,158	$ 33,129

(1) In June 2006, the Operating Partnership executed a second amendment (the "Second Amendment") to the credit agreement governing its Multi-Year Revolving Credit Facility. The Second Amendment, among other things, extends the maturity date of amounts borrowed under the Multi-Year Revolving Credit Facility from October 2010 to October 2011 with respect to $1.2 billion of the commitments. Borrowings with respect to the remaining $48 million in commitments mature in October 2010.

(2) The maturity date of this facility was extended from June 2007 to June 2010 in August 2006. The other terms of the Dixie facility remain unchanged from those described in our annual report on Form 10-K for the year ended December 31, 2005.

(3) The September 30, 2006 amount includes $21.3 million related to fair value hedges and $13.5 million in net unamortized discounts. The December 31, 2005 amount includes $18.2 million related to fair value hedges and $14.1 million in net unamortized discounts.

Parent-Subsidiary guarantor relationships

We guarantee the debt obligations of our Operating Partnership, with the exception of the Dixie revolving credit facility and the senior subordinated notes assumed from GulfTerra. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation.

Operating Partnership debt obligations

Apart from that discussed below, there have been no significant changes in the terms of our Operating Partnership's debt obligations since those reported in our annual report on Form 10-K for the year ended December 31, 2005.

Multi-Year Revolving Credit Facility. At September 30, 2006, we did not have any amounts outstanding under this facility. In June 2006, the Operating Partnership executed a second amendment (the "Second Amendment") to the credit agreement governing its Multi-Year Revolving Credit Facility. The Second Amendment, among other things, extends the maturity date of the Multi-Year Revolving Credit Facility from October 2010 to October 2011 with respect to $1.2 billion of the commitments. Borrowings with respect to $48 million in commitments mature in October 2010. The Second Amendment also modifies the Operating Partnership's financial covenants to, among other things, allow the Operating Partnership to include in the calculation of its Consolidated EBITDA (as defined in the credit agreement) pro forma adjustments for material capital projects. In addition, the Second Amendment allows for the issuance of hybrid debt, such as the $550 million in principal amount of Junior Notes A issued by the Operating Partnership during the third quarter of 2006 (see below).

In March 2006, we generated net proceeds of $430 million in connection with the sale of 18,400,000 of our common units in an underwritten equity offering. In addition, in September 2006, we generated net proceeds of $320.8 million in connection with the sale of 12,650,000 of our common units in an underwritten equity offering. Subsequently, these amounts were contributed to the Operating Partnership, which, in turn, primarily used the amounts to temporarily reduce debt outstanding under its Multi-Year Revolving Credit Facility. See Note 11 for additional information regarding our equity offerings during the first nine months of 2006.

Junior Notes A. The Operating Partnership sold $550 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due 2066 ("Junior Notes A") during the third quarter of 2006. The Operating Partnership used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. The Operating Partnership's payment obligations under Junior Notes A are subordinated to all of its current and future senior indebtedness (as defined in the Indenture Agreement). Enterprise Products Partners has guaranteed repayment of amounts due under Junior Notes A through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Notes A allows the Operating Partnership to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. The indenture agreement also provides that, unless (i) all deferred interest on Junior Notes A has been paid in full as of the most recent interest payment date, (ii) no event of default under the Indenture has occurred and is continuing and (iii) Enterprise Products Partners is not in default of its obligations under related guarantee agreements, then the Operating Partnership and Enterprise Products Partners cannot declare or make any distributions with respect to any of their respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or subordinate to Junior Notes A.

The Junior Notes A will bear interest at a fixed annual rate of 8.375% from July 2006 to August 2016, payable semi-annually in arrears in February and August of each year, commencing in February 2007. After August 2016, the Junior Notes A will bear variable rate interest at an annual rate equal to the 3-month LIBOR rate for the related interest period plus 3.708%, payable quarterly in arrears in February, May, August and November of each year commencing in November 2016. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to the certain provisions. The Junior Notes A mature in August 2066 and are not redeemable by the Operating Partnership prior to August 2016 without payment of a make-whole premium.

In connection with the issuance of Junior Notes A, the Operating Partnership entered into a Replacement Capital Covenant in favor of the covered debt holders (as named therein) pursuant to which the Operating Partnership agreed for the benefit of such debt holders that it would not redeem or repurchase such junior notes unless such redemption or repurchase is made from the proceeds of issuance of certain securities.

Covenants

We were in compliance with the covenants of our consolidated debt agreements at September 30, 2006 and December 31, 2005.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and the weighted-average interest rate paid on our consolidated variable-rate debt obligations during the nine months ended September 30, 2006.

	Range of interest rates paid	**Weighted-average interest rate paid**
Operating Partnership's Multi-Year Revolving Credit Facility	4.87% to 8.25%	5.53%
Dixie Revolving Credit Facility	4.67% to 5.79%	5.18%

Consolidated debt maturity table

Our scheduled maturities of debt principal amounts over the next five years and in total thereafter are presented in the following table. No amounts are currently due in 2006 or 2008.

2007	$ 500,000
2009	500,000
2010	569,068
Thereafter	3,350,000
Total scheduled principal payments	$ 4,919,068

Joint venture debt obligations

We have three unconsolidated affiliates with long-term debt obligations. The following table shows (i) our ownership interest in each entity at September 30, 2006, (ii) total debt of each unconsolidated affiliate at September 30, 2006 (on a 100% basis to the joint venture) and (iii) the corresponding scheduled maturities of such debt.

	Our Ownership Interest	**Total**	**Scheduled Maturities of Debt**					
			2006	**2007**	**2008**	**2009**	**2010**	**After 2010**
Cameron Highway	50.0%	$ 415,000			$ 25,000	$ 25,000	$ 50,000	$ 315,000
Poseidon	36.0%	92,000						92,000
Evangeline	49.5%	30,650	$ 5,000	$ 5,000	5,000	5,000	10,650	
Total		$ 537,650	$ 5,000	$ 5,000	$ 30,000	$ 30,000	$ 60,650	$ 407,000

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, 2006.

Amendment of Cameron Highway debt agreement. In March 2006, Cameron Highway amended the note purchase agreement governing its senior secured notes to primarily address the effect of reduced deliveries of crude oil to Cameron Highway resulting from production delays. In general, this amendment modified certain financial covenants in light of production forecasts made by management. In addition, the amendment increased the face amount of the letters of credit required to be issued by the Operating Partnership and an affiliate of our joint venture partner from $18.4 million each to $36.8 million each.

Also, the amendment specifies that Cameron Highway cannot make distributions to its partners during the period beginning March 30, 2006 and ending on the earlier of (i) December 31, 2007 or (ii) the date on which Cameron Highway's debt service coverage ratios are not less than 1.5 to 1 for three consecutive fiscal quarters. In order for Cameron Highway to resume paying distributions to its partners, no default or event of default can be present or continuing at the date Cameron Highway desires to start paying such distributions.

Amendment of Poseidon debt agreement. In May 2006, Poseidon amended its revolving credit facility to, among other things, reduce commitments from $170 million to $150 million, extend the maturity date from January 2008 to May 2011 and lower the borrowing rate.

11. Partners' Equity

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights and 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.

Capital accounts

In accordance with our Partnership Agreement, capital accounts are maintained for our general partner and our 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 100% 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).

The following table reflects the number of common units issued and the net proceeds received from each public offering during the nine months ended September 30, 2006:

Month of Offering	Number of common units issued	Net Proceeds from Sale of Common Units: Contributed by Limited Partners	Contributed by General Partner	Total
February 2006 (1)	418,190	$ 9,972	$ 203	$ 10,175
March 2006 (2)	18,400,000	421,419	8,601	430,020
May 2006 (1)	477,646	11,441	234	11,675
August 2006 (1)	2,410,600	61,288	1,251	62,539
September 2006 (3)	12,650,000	314,400	6,402	320,802
Totals	34,356,436	$ 818,520	$ 16,691	$ 835,211

(1) These units were issued primarily in connection with our distribution reinvestment plan. We used the proceeds from the February and May 2006 offerings primarily for general partnership purposes. We used all of the proceeds from the August 2006 offering to temporarily reduce debt outstanding under our Multi-Year Revolving Credit Facility.
(2) Net proceeds from this offering were used to temporarily reduce debt outstanding under our Multi-Year Revolving Credit Facility.
(3) Net proceeds of $260 million from this offering were used to temporarily repay amounts outstanding under our Multi-Year Revolving Credit Facility. The remainder of net proceeds from this offering was used for general partnership purposes.

We have a universal shelf registration statement on file with the SEC registering the issuance of up to $4 billion of equity and debt securities. After taking into account past issuances of securities under this universal registration statement, we can issue approximately $2.1 billion of additional securities under this registration statement as of September 30, 2006.

In July 2006, we issued approximately 7.1 million of our common units as partial consideration for our Encinal acquisition. In August 2006, we filed a registration statement with the SEC for the resale of these common units.

Summary of limited partner transactions

The following table details the changes in limited partners' equity since December 31, 2005:

	Limited Partners: Common units	Restricted Common units	Total
Balance, December 31, 2005	$ 5,542,700	$ 18,638	$ 5,561,338
Net income	396,838	921	397,759
Operating leases paid by EPCO	1,548	3	1,551
Cash distributions to partners	(539,845)	(1,144)	(540,989)
Unit option reimbursements to EPCO	(1,697)		(1,697)
Net proceeds from sales of common units	818,520		818,520
Common units issued to Lewis in connection with Encinal acquisition	181,112		181,112
Proceeds from exercise of unit options	4,044		4,044
Change in accounting method for equity awards (see Note 3)	(895)	(14,919)	(15,814)
Amortization of equity awards	1,679	4,370	6,049
Balance, September 30, 2006	$ 6,404,004	$ 7,869	$ 6,411,873

Unit history

The following table details the outstanding balance of each class of units for the periods and at the dates indicated:

	Limited Partners	
	Common Units	Restricted Common Units
Balance, December 31, 2005	389,109,564	751,604
Common units issued in February 2006	418,190	
Common units issued in February 2006 in connection with exercise of unit options	29,000	
Restricted common units issued in February 2006		17,500
Vesting of restricted units in February 2006	2,434	(2,434)
Common units issued in connection with March 2006 public offering	18,400,000	
Forfeiture of restricted units in March 2006		(26,021)
Vesting of restricted units in April 2006	37,277	(37,277)
Forfeiture of restricted units in April 2006		(1,000)
Common units issued in May 2006	477,646	
Common units issued in May 2006 in connection with exercise of unit options	34,000	
Restricted common units issued in May 2006		382,900
Forfeiture of restricted units in May 2006		(1,000)
Forfeiture of restricted units in June 2006		(9,255)
Issuance of units in July 2006 in connection with Encinal business combination (see Note 8)	7,115,844	
Common units issued in August 2006 in connection with exercise of unit options	92,000	
Common units issued in August 2006	2,410,600	
Restricted common units issued in August 2006		10,000
Forfeiture of restricted common units in August 2006		(27,355)
Common units issued in September 2006	12,650,000	
Forfeiture of restricted common units in September 2006		(6,000)
Balance, September 30, 2006	430,776,555	1,051,662

Distributions

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.

Our quarterly cash distributions for 2006 are presented in the following table:

	Cash Distribution History		
	Distribution per Unit	Record Date	Payment Date
1st Quarter 2006	$ 0.4450	Apr. 28, 2006	May 10, 2006
2nd Quarter 2006	$ 0.4525	Jul. 31, 2006	Aug. 10, 2006
3rd Quarter 2006	$ 0.4600	Oct. 31, 2006	Nov. 8, 2006

Accumulated other comprehensive income

The following table summarizes transactions affecting our accumulated other comprehensive income since December 31, 2005.

	Commodity Financial Instruments	Interest Rate Financial Instruments	Accumulated Other Comprehensive Income Balance
Balance, December 31, 2005		$ 19,072	$ 19,072
Change in fair value of commodity financial instruments	$ 4,880		4,880
Reclassification of gain on settlement of interest rate financial instruments		(3,158)	(3,158)
Balance, September 30, 2006	$ 4,880	$ 15,914	$ 20,794

During the remainder of 2006, we will reclassify $1.1 million from accumulated other comprehensive income to earnings as a reduction in consolidated interest expense.

12. Business Segments

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technology 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 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 (or consolidated) segment gross operating margin as 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 expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of changes in accounting principles. 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 and operating costs and expenses include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of all material 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 customers and/or suppliers. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our 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 and petrochemicals. Our asset system has multiple entry points. 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. At each point along our asset system, we typically earn fee-based revenues based on volumes received or we receive ownership of products such as NGLs in lieu of fees.

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 investees to our operations, we believe the treatment of earnings from our equity method investees as a component of gross operating margin and operating income is meaningful and appropriate.

Historically, 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 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. Beginning with the fourth quarter of 2006, a portion of our revenues will be earned in Canada. See Note 19 for information regarding our acquisition of a Canadian affiliate of EPCO in October 2006.

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.

The following table shows 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,	
		2006	2005	2006	2005
Revenues (1)		$ 3,872,525	$ 3,249,291	$ 10,640,452	$ 8,476,581
Less:	Operating costs and expenses (1)	(3,584,783)	(3,045,345)	(9,955,231)	(7,959,122)
Add:	Equity in income of unconsolidated affiliates (1)	2,265	3,703	14,306	14,563
	Depreciation, amortization and accretion in operating costs and expenses (2)	112,412	103,028	325,180	304,041
	Operating lease expense paid by EPCO (2)	526	528	1,582	1,584
	Loss (gain) on sale of assets in operating costs and expenses (2)	(3,204)	611	(3,401)	(4,742)
Total segment gross operating margin		$ 399,741	$ 311,816	$ 1,022,888	$ 832,905

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

A reconciliation of 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,	
	2006	2005	2006	2005
Total segment gross operating margin	$ 399,741	$ 311,816	$ 1,022,888	$ 832,905
Adjustments to reconcile total gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(112,412)	(103,028)	(325,180)	(304,041)
Operating lease expense paid by EPCO	(526)	(528)	(1,582)	(1,584)
Gain (loss) on sale of assets in operating costs and expenses	3,204	(611)	3,401	4,742
General and administrative costs	(15,823)	(13,252)	(45,798)	(46,655)
Consolidated operating income	274,184	194,397	653,729	485,367
Other expense	(60,657)	(59,144)	(169,705)	(167,139)
Income before provision for income taxes, minority interest and cumulative effect of change in accounting principle	$ 213,527	$ 135,253	$ 484,024	$ 318,228

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

	Reportable Segments					
	NGL Pipelines & Services	**Onshore Pipelines & Services**	**Offshore Pipelines & Services**	**Petrochemical Services**	**Adjustments and Eliminations**	**Consolidated Totals**
Revenues from third parties:						
Three months ended September 30, 2006	$ 2,797,651	$ 341,537	$ 53,936	$ 547,038		$ 3,740,162
Three months ended September 30, 2005	2,426,672	304,215	25,018	374,422		3,130,327
Nine months ended September 30, 2006	7,689,559	1,062,948	105,794	1,446,279		10,304,580
Nine months ended September 30, 2005	6,229,322	810,362	86,550	1,092,242		8,218,476
Revenues from related parties:						
Three months ended September 30, 2006	48,699	83,521	143			132,363
Three months ended September 30, 2005	11,869	106,870	203	22		118,964
Nine months ended September 30, 2006	92,748	242,390	734			335,872
Nine months ended September 30, 2005	15,489	241,901	642	73		258,105
Intersegment and intrasegment revenues:						
Three months ended September 30, 2006	1,105,719	30,377	484	101,452	$ (1,238,032)	
Three months ended September 30, 2005	792,744	10,047	403	106,598	(909,792)	
Nine months ended September 30, 2006	3,079,511	90,106	1,187	287,718	(3,458,522)	
Nine months ended September 30, 2005	2,289,451	28,464	1,031	248,485	(2,567,431)	
Total revenues:						
Three months ended September 30, 2006	3,952,069	455,435	54,563	648,490	(1,238,032)	3,872,525
Three months ended September 30, 2005	3,231,285	421,132	25,624	481,042	(909,792)	3,249,291
Nine months ended September 30, 2006	10,861,818	1,395,444	107,715	1,733,997	(3,458,522)	10,640,452
Nine months ended September 30, 2005	8,534,262	1,080,727	88,223	1,340,800	(2,567,431)	8,476,581
Equity in income in unconsolidated affiliates:						
Three months ended September 30, 2006	1,422	794	(330)	379		2,265
Three months ended September 30, 2005	773	604	2,321	5		3,703
Nine months ended September 30, 2006	4,864	2,300	6,373	769		14,306
Nine months ended September 30, 2005	8,058	1,866	4,221	418		14,563
Gross operating margin by individual business segment and in total:						
Three months ended September 30, 2006	232,037	77,489	38,364	51,851		399,741
Three months ended September 30, 2005	153,760	93,513	16,922	47,621		311,816
Nine months ended September 30, 2006	549,401	260,943	76,131	136,413		1,022,888
Nine months ended September 30, 2005	427,392	257,774	62,180	85,559		832,905
Segment assets:						
At September 30, 2006	3,180,179	3,667,364	743,341	506,087	1,304,698	9,401,669
At December 31, 2005	3,075,048	3,622,318	632,222	504,841	854,595	8,689,024
Investments in and advances to unconsolidated affiliates (see Note 7):						
At September 30, 2006	119,015	87,201	315,006	18,964		540,186
At December 31, 2005	130,376	4,644	316,844	20,057		471,921
Intangible assets (see Note 9):						
At September 30, 2006	418,675	394,415	157,627	47,978		1,018,695
At December 31, 2005	275,778	413,843	174,532	49,473		913,626
Goodwill (see Note 9):						
At September 30, 2006	152,444	282,977	82,386	73,690		591,497
At December 31, 2005	54,960	282,997	82,386	73,690		494,033

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,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
NGL Pipelines & Services:				
Sale of NGL products	$ 2,640,568	$ 2,218,620	$ 7,276,342	$ 5,680,345
Percent of consolidated revenues	68%	68%	68%	67%
Onshore Natural Gas Pipelines & Services:				
Sale of natural gas	$ 316,273	$ 290,166	$ 954,111	$ 713,692
Percent of consolidated revenues	8%	9%	9%	8%
Petrochemical Services:				
Sale of natural gas	$ 417,395	$ 273,319	$ 1,157,184	$ 899,033
Percent of consolidated revenues	11%	8%	11%	11%

13. Related Party Transactions

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
Revenues from consolidated operations				
EPCO and affiliates	$ 47,812	$ 1	$ 86,892	$ 287
Unconsolidated affiliates	84,551	118,963	248,980	257,818
Total	$ 132,363	$ 118,964	$ 335,872	$ 258,105
Operating costs and expenses				
EPCO and affiliates	$ 78,570	$ 66,302	$ 244,632	$ 189,124
Unconsolidated affiliates	4,523	11,464	19,113	21,930
Total	$ 83,093	$ 77,766	$ 263,745	$ 211,054
General and administrative expenses				
EPCO and affiliates	$ 10,728	$ 8,640	$ 32,566	$ 28,528

Relationship with EPCO and affiliates

General. We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities:

- EPCO and its private company subsidiaries;
- Enterprise Products GP, our sole general partner;
- Enterprise GP Holdings, which owns and controls our general partner;
- the Employee Partnership; and
- TEPPCO and TEPPCO GP, which are controlled by affiliates of EPCO.

Unless noted otherwise, our agreements with EPCO are not the result of arm’s length transactions. As a result, we cannot provide assurance that the terms and provisions of such agreements are at least as favorable to us as we could have obtained from unaffiliated third parties.

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, 2006, EPCO and its affiliates beneficially owned 146,379,464 (or 33.9%) of our outstanding common units, which includes 13,454,498 of our common units owned by Enterprise GP Holdings. In addition, at September 30, 2006, EPCO and its affiliates beneficially owned 86.7% 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 $73.5 million and $55.4 million from us during the nine months ended September 30, 2006 and 2005, respectively. These amounts include $62.5 million and $45.9 million of incentive distributions for the nine months ended September 30, 2006 and 2005, 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 depends on the cash distributions it receives from us, Enterprise GP Holdings and other investments to fund its other operations and to meet its debt obligations. EPCO and its affiliates received $225.5 million and $243.9 million in cash distributions from us during the nine months ended September 30, 2006 and 2005, respectively, in connection with its limited and general partner interests in us.

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 an 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. The ownership interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility.

We have entered into an agreement with an affiliate of EPCO to provide trucking services to us for the transportation of NGLs and other products. We also lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates. In addition, we buy and sell NGL products to and from a Canadian affiliate of EPCO at market-related prices in the normal course of business. We acquired this foreign affiliate in October 2006. See Note 19 for additional information regarding this acquisition.

On November 2, 2006, a newly formed and wholly owned subsidiary of ours, Duncan Energy Partners, filed its initial registration statement for a proposed public offering of its common units. Duncan Energy Partners will own interests in certain of our midstream energy businesses and will have related party transactions with us and other affiliates of EPCO. For additional information regarding this subsequent event, please read Note 19.

Relationship with TEPPCO. We received $14 million and $31.1 million from TEPPCO during the three and nine months ended September 30, 2006, respectively, from the sale of hydrocarbon products. During the three months ended September 30, 2006 and 2005, we paid TEPPCO $7.1 million and $4 million, respectively, for NGL pipeline transportation and storage services. We paid TEPPCO $17.7 million and $12.6 million for NGL pipeline transportation and storage services during the nine months ended September 30, 2006 and 2005, respectively.

Affiliates of EPCO and Dan Duncan LLC own the general partner of TEPPCO and 2,500,000 common units of TEPPCO. See Note 15 for recent litigation involving us and TEPPCO.

In March 2006, we paid $38.2 million to TEPPCO for its Pioneer natural gas processing plant located in Opal, Wyoming and certain natural gas processing rights related to production from the Jonah and Pinedale fields located in the Greater Green River Basin in Wyoming. After an in-depth consideration of relevant factors, this transaction was approved by the Audit and Conflicts Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO. In addition, each party received a fairness opinion rendered by an independent advisor. TEPPCO will have no continued involvement in the contracts or in the operations of the Pioneer facility. The unaudited pro forma financial impact of this transaction is not significant.

In August 2006, we announced a joint venture in which we and TEPPCO will be partners in TEPPCO's Jonah Gas Gathering Company ("Jonah"). Jonah owns the Jonah Gas Gathering System ("the Jonah system"), located in the Greater Green River Basin of southwestern Wyoming. The Jonah 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-use 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 entered into in February 2006. In connection with the joint venture arrangement, we and TEPPCO intend to continue the Phase V expansion, which is expected to increase the capacity of the Jonah system from 1.5 Bcf/d to 2.4 Bcf/d and to significantly reduce system operating pressures, which is anticipated to 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 Bcf/d, is projected to be completed in the first quarter of 2007 at an estimated cost of approximately $295 million. The second portion of the expansion is expected to cost approximately $170 million and be completed by the end of 2007.

We will continue to 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. From August 1, 2006, we and TEPPCO equally share in the construction costs of the Phase V expansion.

In the third quarter of 2006, TEPPCO reimbursed us $65 million for 50% of the Phase V cost incurred through August 1, 2006 (including carrying costs of $1.3 million). We had a receivable of $18.9 million from TEPPCO at September 30, 2006, for costs incurred through September 30, 2006. 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%. We will operate the system.

The Jonah joint venture is governed by a management committee comprised of two representatives approved by us and two appointed by TEPPCO, each with equal voting power. After an in-depth consideration of relevant factors, this transaction was approved by the Audit and Conflicts Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO. In addition, each party received a fairness opinion rendered by an independent advisor.

We will account for our investment in the Jonah joint venture using the equity method. As a result of entering into the Jonah joint venture, we reclassified $52.1 million expended on this project through July 31, 2006 (representing our 50% share) from Other Assets to Investments in Unconsolidated Affiliates. The remaining $52.1 million we spent through this date is included in the $65 million we billed TEPPCO (see above). See Note 7 for information regarding our investments in unconsolidated affiliates.

We have agreed to indemnify TEPPCO from any and all losses, claims, demands, suits, liability, costs and expenses arising out of or related to breaches of our representations, warranties, or covenants related to the Jonah joint venture. A claim for indemnification cannot be filed until the losses suffered by TEPPCO exceed $1 million. The maximum potential amount of future payments under the indemnity agreement is limited to $100 million. All indemnity payments are net of insurance recoveries that TEPPCO may receive from third-party insurers. We carry insurance coverage that may offset any payments required under the indemnification.

See Note 6 for information regarding our purchase and lease of certain pipeline segments from TEPPCO during the fourth quarter of 2006.

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 ("ASA"). We and our general partner, Enterprise GP Holdings and its general partner, and TEPPCO and its general partner, among other affiliates, are parties to the ASA. We reimburse EPCO for the costs of its employees who perform operating functions for us and for costs related to its other management and administrative employees.

Relationships with unconsolidated affiliates

Our significant related party 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.

14. Earnings per Unit

Basic earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the weighted-average number of distribution-bearing units outstanding during a period. Diluted earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the sum of (i) the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit); (ii) the weighted-average number of time-vested and performance-based restricted common 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, the restricted 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 in accordance with 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 shows the allocation of net income to our general partner for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
Net income	$ 208,302	$ 131,169	$ 468,374	$ 311,084
Less incentive earnings allocations to Enterprise Products GP	(22,386)	(16,755)	(62,497)	(45,891)
Net income available after incentive earnings allocation	185,916	114,414	405,877	265,193
Multiplied by Enterprise Products GP ownership interest	2.0%	2.0%	2.0%	2.0%
Standard earnings allocation to Enterprise Products GP	$ 3,718	$ 2,288	$ 8,118	$ 5,304
Incentive earnings allocation to Enterprise Products GP	$ 22,386	$ 16,755	$ 62,497	$ 45,891
Standard earnings allocation to Enterprise Products GP	3,718	2,288	8,118	5,304
Enterprise Products GP interest in net income	$ 26,104	$ 19,043	$ 70,615	$ 51,195

The following table shows the calculation of our limited partners' interest in net income and basic and diluted earnings per unit.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
Income before change in accounting principle and Enterprise Products GP interest	$ 208,302	$ 131,169	$ 466,899	$ 311,084
Cumulative effect of change in accounting principle			1,475	
Net income	208,302	131,169	468,374	311,084
Enterprise Products GP interest in net income	(26,104)	(19,043)	(70,615)	(51,195)
Net income available to limited partners	$ 182,198	$ 112,126	$ 397,759	$ 259,889
BASIC EARNINGS PER UNIT				
Numerator				
Income before change in accounting principle and Enterprise Products GP interest	$ 208,302	$ 131,169	$ 466,899	$ 311,084
Cumulative effect of change in accounting principle			1,475	
Enterprise Products GP interest in net income	(26,104)	(19,043)	(70,615)	(51,195)
Limited partners' interest in net income	$ 182,198	$ 112,126	$ 397,759	$ 259,889
Denominator				
Common units	418,790	384,468	407,539	380,429
Time-vested restricted units	1,064	674	930	555
Common units	419,854	385,142	408,469	380,984
Basic earnings per unit				
Income per unit before change in accounting principle and Enterprise Products GP interest	$ 0.50	$ 0.34	$ 1.14	$ 0.82
Enterprise Products GP interest in net income	(0.07)	(0.05)	(0.17)	(0.13)
Limited partners' interest in net income	$ 0.43	$ 0.29	$ 0.97	$ 0.69
DILUTED EARNINGS PER UNIT				
Numerator				
Income before change in accounting principle and Enterprise Products GP interest	$ 208,302	$ 131,169	$ 466,899	$ 311,084
Cumulative effect of change in accounting principle			1,475	
Enterprise Products GP interest in net income	(26,104)	(19,043)	(70,615)	(51,195)
Limited partners' interest in net income	$ 182,198	$ 112,126	$ 397,759	$ 259,889
Denominator				
Common units	418,790	384,468	407,539	380,429
Time-vested restricted units	1,064	674	930	555
Performance-based restricted units	16	45	23	51
Incremental option units	332	346	271	515
Total	420,202	385,533	408,763	381,550
Diluted earnings per unit				
Income per unit before change in accounting principle and Enterprise Products GP interest	$ 0.50	$ 0.34	$ 1.14	$ 0.82
Enterprise Products GP interest in net income	(0.07)	(0.05)	(0.17)	(0.13)
Limited partners' interest in net income	$ 0.43	$ 0.29	$ 0.97	$ 0.69

15. Commitments and Contingencies

Litigation

On occasion, we are named as a defendant in litigation relating to our normal business activities, including regulatory and environmental matters. Although we insure 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 not aware of any significant litigation, pending or threatened, that may have a significant adverse effect on our financial position, cash flows or results of operations.

A number of lawsuits have been filed by municipalities and other water suppliers against various manufacturers of reformulated gasoline containing methyl tertiary butyl ether ("MTBE"). In general, such suits have not named manufacturers of MTBE 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 MTBE manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits.

We acquired additional ownership interests in our octane-additive production facility from affiliates of Devon Energy Corporation ("Devon"), which sold us its 33.3% interest in 2003, and Sunoco, Inc. ("Sun"), which sold us its 33.3% interest in 2004. As a result of these acquisitions, we own 100% of our Mont Belvieu, Texas octane-additive production facility. Devon and Sun have indemnified us for any liabilities (including potential liabilities as described in the preceding paragraph) that are in respect of periods prior to the date we purchased such interests. There are no dollar limits or deductibles associated with the indemnities we received from Sun and Devon with respect to potential claims linked to the period of time they held ownership interests in our octane-additive production facility.

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. The complaint names as defendants (i) TEPPCO, its directors, and certain of its affiliates; (ii) us and certain of our affiliates, including the parent company of our general partner; (iii) EPCO, Inc.; and (iv) Dan L. Duncan. The complaint alleges, among other things, that the defendants have caused TEPPCO to enter into certain transactions with us or our affiliates that are 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 system entered into by TEPPCO and one of our affiliates in August 2006 (see Note 13) and the sale by TEPPCO to one of our affiliates of the Pioneer gas processing plant in March 2006 (see Note 6). The 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 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.

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. Lease and rental expense included in operating income was $10.3 million and $8.1 million for the three months ended September 30, 2006 and 2005, respectively. For the nine months ended September 30, 2006 and 2005, lease and rental expense included in operating income was $30 million and $26.2 million, respectively.

There have been no material changes in our operating lease commitments since December 31, 2005, except for the renewal of our Wilson natural gas storage facility lease. During the first quarter of 2006, we exercised our right to renew the Wilson lease for an additional 20-year period. Our rental payments under the renewal agreement are at a fixed rate. Under the renewal agreement, we have the option to purchase the Wilson natural gas storage facility at either December 31, 2024 for $61 million or January 25, 2028 for $55 million. In addition, the lessor, at its election, may cause us to purchase the facility for $65 million at the end of any calendar quarter beginning on March 31, 2008 and extending through December 31, 2023. After adjusting for the renewal, the incremental future minimum lease payments associated with our lease of the Wilson natural gas storage facility are as follows: $4.1 million, 2008; $5.5 million, 2009; $5.5 million, 2010; and $94.9 million thereafter.

Performance guaranty

In December 2004, a subsidiary of the Operating Partnership entered into the Independence Hub Agreement (the "Hub Agreement") with six oil and natural gas producers. The Hub Agreement, as amended, obligates the subsidiary (i) to construct an offshore platform production facility to process 1 Bcf/d of natural gas and condensate and (ii) to process certain natural gas and condensate production of the six producers following construction of the platform facility.

In conjunction with the Hub Agreement, our Operating Partnership guaranteed the performance of its subsidiary under the Hub Agreement up to $426 million. In December 2004, 20% of this guaranteed amount was assumed by Helix Energy Solutions Group, Inc. (formerly known as Cal Dive International, Inc.), our joint venture partner in the Independence Hub project. The remaining $341 million represents our share of the anticipated construction cost of the platform facility. This amount represents the cap on our Operating Partnership's potential obligation to the six producers for the cost of constructing the platform under the remote scenario where the six producers finish construction of the platform facility. This performance guarantee continues until the earlier to occur of (i) all of the guaranteed obligations of the subsidiary shall have been terminated, paid or otherwise discharged in full, (ii) upon mutual written consent of our Operating Partnership and the producers or (iii) mechanical completion of the production facility. We currently expect that mechanical completion of the platform will occur in the first quarter of 2007; therefore, we anticipate that the performance guaranty will exist until at least this future period.

In accordance with FIN 45, "*Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*," we recorded the fair value of the performance guaranty using an expected present value approach. Given the remote probability that our Operating Partnership would be required to perform under this guaranty, we have estimated the fair value of the performance guaranty at approximately $1.2 million, which is a component of other current liabilities on our Unaudited Condensed Consolidated Balance Sheet at September 30, 2006.

Other Claims

As part of our normal industry 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, 2006, our contingent claims against such parties were approximately $2 million and claims against us were approximately $34 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated. However, in our opinion, the likelihood of a material adverse outcome related to 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.

16. Significant Risks and Uncertainties – Weather-Related Risks

EPCO renewed its property and casualty insurance programs during the second quarter of 2006. As a result of severe hurricanes such as Katrina and Rita that occurred in 2005, market conditions for obtaining property damage insurance coverage were difficult. Under our renewed insurance programs, coverage is more restrictive, including increased physical damage and business interruption deductibles. For example, our deductible for onshore physical damage increased from $2.5 million to $5 million per event and our deductible period for onshore business interruption claims increased from 30 days to 60 days. Additional restrictions will also be applied in the event of damage from named windstorms.

In addition to changes in coverage, the cost of property damage insurance increased substantially from prior periods. At present, our annualized cost of insurance premiums for all lines of coverage is approximately $49.2 million, which represents a $28.1 million (or 133%) increase from our 2005 annualized insurance cost.

The following is a discussion of the general status of insurance claims related to significant storm events that affected our assets in 2004 and 2005. To the extent we include estimates regarding the dollar value of damages, please be aware that a change in our estimates may occur as additional information becomes available to us.

Hurricane Ivan insurance claims. Our final purchase price allocation related to the merger of GulfTerra with a wholly owned subsidiary of Enterprise Products Partners in September 2004 (the “GulfTerra Merger”) included a $26.2 million receivable for insurance claims related to expenditures to repair property damage to certain pre-merger GulfTerra assets caused by Hurricane Ivan. During the first nine months of 2006, we received cash reimbursements from insurance carriers totaling $24.1 million related to these property damage claims, and we expect to recover the remaining $2.1 million in late 2006. If the final recovery of funds is different than the amount previously expended, we will recognize an income impact at that time.

In addition, we have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan. During the first nine months of 2006, we received claim proceeds of $17.4 million. To the extent we receive cash proceeds from business interruption insurance claims, they are recorded as a gain in our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income in the period of receipt.

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. Repair of property damage to our facilities is continuing. To the extent that insurance proceeds from property damage claims do not cover our estimated recoveries (in excess of the $5 million of insurance deductibles we expensed during the third quarter of 2005), such shortfall will be charged to earnings when realized. We recorded $81.4 million of estimated recoveries from property damage claims arising from Hurricanes Katrina and Rita, based on amounts expended through September 30, 2006. During the first nine months of 2006, we received $9.7 million of physical damage proceeds.

In addition, during the first nine months of 2006 we received $45.1 million of business interruption proceeds. To the extent we receive cash proceeds from business interruption claims, they are recorded as a gain in our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income in the period of receipt. We estimate that up to $25 million of additional business interruption proceeds could be received by the end of 2007. Such additional amounts are subject to the review and concurrence of our insurers. Reviews of the outstanding claims are ongoing.

The following table summarizes our cash receipts with respect to business interruption and property damage proceeds for Hurricanes Ivan, Katrina and Rita for the periods indicated.

	For The Three Months Ended September 30, 2006	For The Nine Months Ended September 30, 2006
Business interruption proceeds:		
Hurricane Ivan	$ 5,157	$ 17,383
Hurricane Katrina	24,325	24,325
Hurricane Rita	20,740	20,740
Total proceeds	$ 50,222	$ 62,448
Property damage proceeds:		
Hurricane Ivan		$ 24,104
Hurricane Katrina	$ 6,975	6,975
Hurricane Rita	2,730	2,730
Total	$ 9,705	$ 33,809

17. Supplemental Cash Flow Information

We prepare our Unaudited Condensed Statements of Consolidated Cash Flows 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 the like, (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 assets or gains or losses from the extinguishment of debt and (iv) other non-cash amounts such as depreciation, amortization and changes in the fair market value of 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,	
	2006	2005
Decrease (increase) in:		
Accounts and notes receivable	$ 72,878	$ (203,835)
Inventories	(122,672)	(386,057)
Prepaid and other current assets	(42,597)	(31,287)
Other assets	(3,229)	49,484
Increase (decrease) in:		
Accounts payable	21,799	(143,634)
Accrued gas payable	63,667	369,568
Accrued expenses	63,500	18,116
Accrued interest	9,334	1,344
Other current liabilities	100,858	11,861
Other long-term liabilities	(3,689)	238
Net effect of changes in operating accounts	$ 159,849	$ (314,202)

Third parties may be obligated to reimburse us for all or a portion of project 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 $63.7 million and $40.4 million as contributions in aid of our construction costs during the nine months ended September 30, 2006 and 2005, respectively.

18. Condensed Financial Information of Operating Partnership

The Operating Partnership conducts substantially all of our business. Currently, we have no independent operations and no material assets outside those of our Operating Partnership.

We guarantee the debt obligations of our Operating Partnership, with the exception of the Dixie revolving credit facility and the senior subordinated notes assumed from GulfTerra. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. For additional information regarding our consolidated debt obligations, see Note 10.

The reconciling items between our consolidated financial statements and those of our Operating Partnership are insignificant.

The following table presents unaudited condensed consolidated balance sheet data for the Operating Partnership at the dates indicated:

	September 30, 2006	December 31, 2005
ASSETS		
Current assets	$ 2,146,745	$ 1,960,015
Property, plant and equipment, net	9,401,669	8,689,024
Investments in and advances to unconsolidated affiliates, net	540,186	471,921
Intangible assets, net	1,018,695	913,626
Goodwill	591,497	494,033
Deferred tax asset	3,054	3,606
Other assets	46,058	39,014
Total	$ 13,747,904	$ 12,571,239
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities	$ 2,257,968	$ 1,894,227
Long-term debt	4,884,261	4,833,781
Other long-term liabilities	102,609	84,486
Minority interest	133,394	106,159
Partners' equity	6,369,672	5,652,586
Total	$ 13,747,904	$ 12,571,239
Total Operating Partnership debt obligations guaranteed by us	$ 4,904,000	$ 4,844,000

The following table presents unaudited condensed consolidated statements of operations data for the Operating Partnership for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
Revenues	$ 3,872,525	$ 3,249,291	$ 10,640,452	$ 8,476,581
Costs and expenses	3,599,990	3,058,042	9,997,962	8,003,909
Equity in income of unconsolidated affiliates	2,265	3,703	14,306	14,563
Operating income	274,800	194,952	656,796	487,235
Other income (expense)	(61,209)	(59,483)	(171,134)	(167,699)
Income before provision for income taxes, minority interest and change in accounting principle	213,591	135,469	485,662	319,536
Provision for income taxes	(3,214)	(3,223)	(12,378)	(3,958)
Income before minority interest and change in accounting principle	210,377	132,246	473,284	315,578
Minority interest	(2,028)	(902)	(4,761)	(3,235)
Income before change in accounting principle	208,349	131,344	468,523	312,343
Cumulative effect of change in accounting principle			1,475	
Net income	$ 208,349	$ 131,344	$ 469,998	$ 312,343

19. Subsequent Events

Acquisition of Canadian NGL marketing business from EPCO and Dan L. Duncan

On October 1, 2006, we acquired all of the outstanding stock of an affiliated NGL marketing company located in Canada from EPCO and Dan L. Duncan. The purchase price of this business was $18.5 million in cash, of which $16.4 million was paid to EPCO and the remainder to Dan L. Duncan. The purpose of this business acquisition was to expand our North American operations to serve Canadian-based NGL customers and to enhance our access to Canadian NGL production.

Acquisition of Mexia and Genco pipeline assets from TEPPCO

On October 10, 2006, we purchased certain idle pipeline assets in the Houston, Texas area from TEPPCO for $11.7 million in cash. These purchases are part of the pipeline projects we announced in July 2006 in connection with our new long-term natural gas transportation and storage contracts with CenterPoint Energy Resources Corp. The acquired pipelines will be modified for natural gas service.

Initial Public Offering of Duncan Energy Partners

On November 2, 2006, our subsidiary, Duncan Energy Partners, filed its initial registration statement for a proposed initial public offering of its common units. Duncan Energy Partners was formed in September 2006 as a Delaware limited partnership to own, operate and acquire a diversified portfolio of midstream energy assets. At the closing of Duncan Energy Partner's initial public offering, we will contribute 66% of the equity interests in following subsidiaries to Duncan Energy Partners:

§ *Mont Belvieu Caverns, L.P.* ("Mont Belvieu Caverns"), which receives, stores and delivers NGLs and petrochemical products for industrial customers located along the upper Texas Gulf Coast, which has the largest concentration for petrochemical plants and refineries in the United States.

§ *Acadian Gas, LLC* ("Acadian Gas"), which is 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.

§ *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* ("Lou-Tex Propylene"), which transports chemical-grade propylene between Mont Belvieu, Texas and Sorrento, Louisiana; and a

§ *South Texas NGL Pipelines, LLC* ("South Texas NGL"), which will transport NGLs from Corpus Christi, Texas to Mont Belvieu, Texas. South Texas NGL will own the South Texas NGL pipeline system. See Note 6 for a description of this pipeline.

We expect to retain a 34% ownership interest in each of these entities. In addition, we will own the 2% general partner and expect to own at least 25% of the limited partner interests of Duncan Energy Partners. Our ownership of the limited partner interests of Duncan Energy Partners (following its initial public offering) assumes that the underwriters exercise their overallotment option with respect to the offering. Our Operating Partnership will direct the business operations of Duncan Energy Partners through its ownership and control of Duncan Energy Partners.

From a financial reporting perspective, the formation of Duncan Energy Partners had no effect on our financial statements at September 30, 2006. Beginning with the quarterly period in which the initial public offering of Duncan Energy Partners is completed, we will consolidate the results of Duncan Energy Partners with minority interest treatment for the common units of Duncan Energy Partners owned by unitholders other than us.

We expect to have significant continuing involvement with all of these assets, including the following types of transactions:

- § We will continue to utilize storage services provided by Mont Belvieu Caverns to support our Mont Belvieu fractionation and other businesses;
- § We will continue to buy from and sell natural gas to Acadian Gas in connection with its normal business activities; and
- § We will be the sole shipper on the NGL pipeline system to be owned by South Texas NGL.

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

For the three and nine months ended September 30, 2006 and 2005.

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." Unless the context requires otherwise, references to "we," "us," "our," or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

We are a North American midstream energy company that provides a wide range of services to producers and consumers of natural gas, natural gas liquids ("NGLs"), crude oil and certain petrochemicals. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating L.P. (our "Operating Partnership").

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 common units of which are listed on the NYSE under the ticker symbol "EPE." We, Enterprise Products GP and Enterprise GP Holdings are affiliates and under common control of Dan L. Duncan, the Chairman and controlling shareholder of EPCO, Inc. ("EPCO").

This quarterly report contains various forward-looking statements and information based on our beliefs and those of Enterprise Products GP, our general partner, as well as assumptions made by us and information currently available to us. Please read the section titled "*Cautionary Statement Regarding Forward-Looking Information*" included within this Item 2.

As generally used in the energy industry and in this document, the terms listed below have the following meanings:

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

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 the general partner of TEPPCO, which is wholly owned by a private company subsidiary of EPCO.

The following discussion and analysis should be read in conjunction with our unaudited condensed consolidated financial statements and 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, 2005 (Commission File No. 1-14323).

RECENT DEVELOPMENTS

The following information highlights our significant developments since December 31, 2005 through the date of this filing. For additional information regarding the capital projects and acquisitions highlighted below, please read "*Capital Spending – Significant Recently Announced Growth Capital Projects*" included within this Item 2.

- § On November 2, 2006, we filed a registration statement on Form S-1 with the SEC relating to a proposed underwritten initial public offering of limited partner interests in Duncan Energy Partners L.P. ("Duncan Energy Partners"). Duncan Energy Partners was formed in September 2006 as a Delaware limited partnership to acquire ownership interests in certain of our midstream energy businesses. For additional information regarding Duncan Energy Partners, please read " *– Other Items – Initial Public Offering of Duncan Energy Partners*" included within this Item 2.

- § In October 2006, we signed definitive agreements with producers to construct, own and operate an offshore oil pipeline that will provide firm gathering services from the Shenzi production field located in the South Green Canyon area of the central Gulf of Mexico.

- § In September 2006, we sold 12,650,000 of our common units in an underwritten public offering (including the over-allotment amount of 1,650,000 common units), which generated net proceeds of approximately $320.8 million.

- § During the third quarter of 2006, the Operating Partnership sold $550 million in principal amount of fixed/floating unsecured junior subordinated notes due 2066 (the "Junior Notes A"). For additional information regarding this issuance of debt, please read "*Liquidity and Capital Resources*" included within this Item 2.

- § In August 2006, we announced a joint venture in which we and TEPPCO will be partners in TEPPCO's Jonah Gas Gathering Company ("Jonah"). Jonah owns the Jonah Gas Gathering System ("the Jonah system"), located in the Greater Green River Basin of southwestern Wyoming. The Jonah 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-use markets. As part of this new joint venture, we and TEPPCO are significantly expanding the Jonah system (the Phase V expansion project).

- § In August 2006, we purchased 223 miles of NGL pipelines extending from Corpus Christi, Texas to Pasadena, Texas from ExxonMobil Pipeline Company. The total purchase price for these assets was $97.7 million in cash. This pipeline (in combination with others to be constructed or acquired) will be used to transport mixed NGLs from our South Texas natural gas processing plants to our Mont Belvieu fractionation facilities.

- § In August 2006, our wholly owned subsidiary, Mid-America Pipeline Company LLC ("Mid-America") executed new long-term transportation agreements with all but one of its current shippers on its Rocky Mountain pipeline pursuant to terms and conditions of Mid-America's open season tariff that was accepted by the Federal Energy Regulatory Commission effective August 6, 2006. Under the terms of the new agreements, shippers have committed to transport all of their current and future NGL production from the Rocky Mountains through the Mid-America Pipeline System to either our Hobbs fractionator (operational by mid-2007) or to Mont Belvieu, Texas via our Seminole Pipeline for a minimum of 10 years and up to a maximum of 20 years. Based on shipper production forecasts and current NGL extraction rates, we expect that these new agreements will fully utilize our Mid-America Pipeline System, including the 50 MBPD Phase I Expansion announced in January 2005.

- In July 2006, we signed long-term agreements with CenterPoint Energy Resources Corp. (“CenterPoint Energy”) to provide firm natural gas transportation and storage services to its natural gas utility, primarily in the Houston, Texas metropolitan area. We will provide CenterPoint Energy with an estimated 14 Bcf per year of natural gas beginning in April 2007. Our deliveries to CenterPoint Energy through these new contracts marks the first time that we have had the opportunity to serve the growing Houston area natural gas market. We are already the primary natural gas service providers to the San Antonio and Austin, Texas markets.

- In July 2006, we acquired the Encinal and Canales natural gas gathering systems and their related gathering and processing contracts and other amounts 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 $326.1 million, which includes $145 million in cash paid to Lewis and the issuance of 7,115,844 of our common units to Lewis.

- In April 2006, we announced plans to expand our Houston Ship Channel NGL import and export facility and related pipeline and other assets to accommodate an expected increase in throughput volumes.

- In March 2006, we purchased the Pioneer natural gas processing plant and certain related natural gas processing rights from TEPPCO for $38.2 million in cash.

- In March 2006, we announced plans to expand our petrochemical assets located in southeast Texas. The plans include the construction of a new propylene fractionator at our Mont Belvieu, Texas facility and the expansion of two refinery grade propylene pipelines.

- In March 2006, we sold 18,400,000 of our common units in a public offering (including the over-allotment amount of 2,400,000 common units), which generated net proceeds of approximately $430 million.

- In January 2006, we announced the execution of a minimum 15-year natural gas processing agreement with an affiliate of the EnCana Corporation (“EnCana”). Under this agreement, we will have the right to process up to 1.3 Bcf/d of EnCana’s natural gas production from the Piceance Basin area of western Colorado. To accommodate this production, we began construction of the Meeker natural gas processing facility in Rio Blanco County, Colorado. In addition, we will construct a 50-mile NGL pipeline that will connect our Meeker processing facility to our Mid-America Pipeline System.

CAPITAL SPENDING

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 that 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, 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 forecast that this trend will continue, and expect independent oil and natural gas companies to consider similar divestitures.

Based on information currently available, we estimate our capital spending for 2006 will approximate $2 billion, of which $1.4 billion was recorded during the first nine months of 2006. All but $30 million of the $0.6 billion we expect to record during the fourth quarter of 2006 is attributable to growth capital projects.

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 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 the 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.

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

	For the Nine Months Ended September 30,	
	2006	**2005**
Capital spending for business combinations:		
Encinal acquisition, including non-cash equity consideration (1)	$ 326,085	
Indirect interests in the Indian Springs natural gas gathering and processing assets		$ 74,854
Storage business acquired from Ferrellgas LP		144,000
Additional ownership interests in Dixie Pipeline Company ("Dixie")		68,608
Additional ownership interests in Mid-America and Seminole pipeline systems		25,000
Other business combinations		12,618
Total capital spending for business combinations	326,085	325,080
Capital spending for property, plant and equipment:		
Growth capital projects	881,397	524,767
Sustaining capital projects	95,274	62,778
Total capital spending for property, plant and equipment	976,671	587,545
Capital spending attributable to unconsolidated affiliates:		
Investment in Jonah	83,294	
Other investments in and advances to unconsolidated affiliates	9,140	77,472
Total capital spending attributable to unconsolidated affiliates	92,434	77,472
Total capital spending	$ 1,395,190	$ 990,097

(1) Reflects a cash payment of $145 million and the fair value of 7,115,844 of our common units issued to Lewis.

Our capital spending for growth capital projects (as presented in the preceding table) are net of amounts we received from third parties as contributions in aid of our construction costs. Such contributions were $63.7 million and $40.4 million for the nine months ended September 30, 2006 and 2005, respectively. 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.

At September 30, 2006, we had $283.2 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 the Shenzi Oil Export Pipeline Project (see below), which is expected to be completed in 2009.

Significant Recently Announced Growth Capital Projects

The following information details our significant growth capital projects as of November 1, 2006. The capital spending amount noted for each project includes accrued expenditures and capitalized interest through September 30, 2006. The forecast amount noted for each project includes a provision for estimated capitalized interest.

Shenzi Oil Export Pipeline Project. In October 2006, we signed definitive agreements with producers to construct, own and operate an oil export pipeline that will provide firm gathering services from the BHP Billiton Plc-operated Shenzi production field located in the South Green Canyon area of the central Gulf of Mexico. The estimated construction cost of this new pipeline is approximately $170 million. As of September 30, 2006, our capital spending with respect to the Shenzi oil pipeline project was $3.6 million.

The Shenzi oil export pipeline will originate at the Shenzi Field, located in 4,300 feet of water at Green Canyon Block 653, approximately 120 miles off the coast of Louisiana. The 83-mile, 20-inch diameter pipeline will have the capacity to transport up to 230 MBPD of crude oil and will connect the Shenzi Field to our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at our Ship Shoal 332B junction platform. We own a 50% interest in the Cameron Highway Oil Pipeline and a 36% interest in the Poseidon Oil Pipeline System and operate both pipelines. The Shenzi oil export pipeline will connect to a platform being constructed by BHP Billiton Plc to develop the Shenzi Field, which is expected to begin production in mid-2009.

Jonah Joint Venture with TEPPCO and the Phase V Expansion. In August 2006, we announced a joint venture in which we and TEPPCO will be partners in Jonah. Jonah owns the Jonah system, located in the Greater Green River Basin of southwestern Wyoming. The Jonah 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-use 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 entered into in February 2006. In connection with the joint venture arrangement, we and TEPPCO intend to continue the Phase V expansion, which is expected to increase the capacity of the Jonah system from 1.5 Bcf/d to 2.4 Bcf/d and to significantly reduce system operating pressures, which is anticipated to 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 Bcf/d, is projected to be completed in the first quarter of 2007 at an estimated cost of approximately $295 million. The second portion of the expansion is expected to cost approximately $170 million and be completed by the end of 2007. As of September 30, 2006, capital spending with respect to the overall Phase V Expansion (on a 100% basis) was $165.4 million.

We will continue to 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. From August 1, 2006, we and TEPPCO equally share in the construction costs of the Phase V expansion.

In the third quarter of 2006, TEPPCO reimbursed us $65 million for 50% of the Phase V expansion cost incurred through August 1, 2006 (including carrying costs of $1.3 million). We had a receivable of $18.9 million from TEPPCO at September 30, 2006, for costs incurred through September 30, 2006. 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%. We will operate the system.

The Jonah joint venture is governed by a management committee comprised of two representatives approved by us and two appointed by TEPPCO, each with equal voting power. After an in-depth consideration of relevant factors, this transaction was approved by the Audit and Conflicts Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO. In addition, each party received a fairness opinion rendered by an independent advisor.

We will account for our investment in the Jonah joint venture using the equity method. As a result of entering into the Jonah joint venture, we reclassified amounts expended on this project through August 2006 from Other Assets to Investments in and Advances to Unconsolidated Affiliates.

We have agreed to indemnify TEPPCO from any and all losses, claims, demands, suits, liability, costs and expenses arising out of or related to breaches of our representations, warranties, or covenants related to the Jonah joint venture. A claim for indemnification cannot be filed until the losses suffered by TEPPCO exceed $1 million. The maximum potential amount of future payments under the indemnity agreement is limited to $100 million. All indemnity payments are net of insurance recoveries that TEPPCO may receive from third-party insurers. We carry insurance coverage that may offset any payments required under the indemnification.

South Texas NGL Pipeline System Project. In August 2006, we acquired a 223-mile pipeline from ExxonMobil Pipeline Company for $97.7 million in cash. This pipeline originates in Corpus Christi, Texas and extends to Pasadena, Texas. This pipeline segment will be expanded (the “Phase I expansion”) to (i) connect with our Armstrong and Shoup NGL fractionation facilities through the construction of 45 miles of pipeline laterals; (ii) lease from TEPPCO a 10-mile interconnecting pipeline extending from Pasadena, Texas to Baytown, Texas; and (iii) purchase an additional 10-mile pipeline from TEPPCO that will connect the leased TEPPCO pipeline to Mont Belvieu, Texas. The purchase of the 10-mile segment from TEPPCO is estimated to cost $8 million and be completed during the fourth quarter of 2006. The primary term of the TEPPCO pipeline lease will expire in July 2007, and will continue on a month-to-month basis subject to customary termination provisions. Collectively, this 288-mile pipeline will be termed the South Texas NGL pipeline system. The South Texas NGL pipeline system is not in operation, but it is currently undergoing modifications, extensions and interconnections as described above to allow it to transport NGLs beginning in January 2007.

During 2007, we will construct an additional 21 miles of pipeline (the “Phase II upgrade”) to replace (i) the 10-mile pipeline we will lease from TEPPCO and (ii) certain segments of the pipeline we acquired in August 2006 from ExxonMobil Pipeline Company. The Phase II upgrade is expected to provide a significant increase in pipeline capacity and be operational during the third quarter of 2007.

We estimate the cost of the Phase I expansion to be $37.7 million, which includes the $8 million we will pay TEPPCO to acquire its 10-mile Baytown to Mont Belvieu pipeline. We expect the Phase II upgrade to cost an additional $30.9 million. As of September 30, 2006, our capital spending with respect to the South Texas NGL pipeline system was $104.4 million, which includes the $97.7 million we paid in August 2006.

This pipeline system will be owned by South Texas NGL Pipelines, LLC, which will be majority owned by Duncan Energy Partners. For additional information regarding Duncan Energy Partners, please read “ *– Other Items – Initial Public Offering of Duncan Energy Partners*” included within this Item 2.

Texas Intrastate Pipeline Expansion Projects. In July 2006, we signed long-term agreements with CenterPoint Energy to provide firm natural gas transportation and storage services to its natural gas utility, primarily in the Houston, Texas metropolitan area. We will provide CenterPoint Energy with an estimated 14 Bcf per year of natural gas beginning in April 2007. To provide these new services, we will enhance our Texas Intrastate natural gas pipeline system through a combination of pipeline and compression projects, including the expansion of our natural gas storage facilities in Texas, acquisition of certain pipeline laterals located in the Houston, Texas area and the construction of eleven new city gate delivery stations. The total capital cost of these projects is estimated to be $110 million and will be completed in phases throughout 2006 and 2007. As of September 30, 2006, our capital spending with respect to these natural gas pipeline projects was $0.2 million. As part of this expansion project, we purchased certain idle pipeline assets in the Houston, Texas area from TEPPCO for $11.7 million in cash in October 2006.

Encinal Acquisition. In July 2006, we acquired the Encinal and Canales natural gas gathering systems and related gathering and processing contracts and other amounts that comprised the South Texas natural gas transportation and processing business of Lewis. The aggregate value of total consideration we paid or issued to complete this business combination, referred to as the Encinal acquisition, was $326.1 million.

The Encinal and Canales gathering systems are located in South Texas and are connected to over 1,450 natural gas production wells tapped into the Olmos and Wilcox formations. The Encinal system consists of 452 miles of pipeline, which is comprised 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, volumes gathered by the Encinal and Canales systems are transported by our existing South Texas natural gas pipeline system and are processed by our South Texas natural gas processing plants.

As part of this transaction, we acquired long-term natural gas processing and gathering dedications from Lewis. First, these gathering systems will be supported by a life of reserves gathering and processing dedication of Lewis' natural gas production from the Olmos formation. Second, Lewis entered into a 10-year agreement with us for the transportation of natural gas treated at its Big Reef facility. This facility processes natural gas production from the southern portion of the Edwards Trend in South Texas. Third, Lewis entered into a 10-year gathering and processing agreement with us for rich gas developed below the Olmos formation.

The total consideration paid or granted for the Encinal acquisition is summarized in the following table:

Cash payment to Lewis	$ 144,973
Fair value of our 7,115,844 common units issued to Lewis	181,112
Total consideration	$ 326,085

As a result of our preliminary purchase price allocation for the Encinal acquisition, we recorded $132.9 million of amortizable intangible assets. The remaining preliminary amount represents goodwill of $94.9 million, which management attributes to potential future benefits we may realize from our existing South Texas processing and NGL businesses as a result of the Encinal acquisition. Specifically, the long-term dedication rights acquired in connection with the Encinal acquisition are expected to add value to our South Texas processing facilities and related NGL businesses due to increased volumes. For additional information regarding the Encinal acquisition, please read Note 8 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Expansion of Import and Export Capability. In April 2006, we announced an expansion of our NGL import and export terminal located on the Houston Ship Channel. This expansion project will increase offloading capability of our import facility from a maximum peak operating rate of 240 MBPD to 480 MBPD and the maximum loading rate of our export facility from 140 MBPD to 160 MBPD. As part of this expansion project, we will increase the transportation and processing capacities of certain of our assets that serve the terminal in order to accommodate the expected increase in import volumes. This expansion project is expected to cost approximately $59 million and be completed in the second quarter of 2007. As of September 30, 2006, our capital spending with respect to the expansion of import and export capabilities was $2 million.

Wyoming Gas Processing Projects. In March 2006, we paid $38.2 million to TEPPCO for its Pioneer natural gas processing plant located in Opal, Wyoming and certain natural gas processing rights related to production from the Jonah and Pinedale fields located in the Greater Green River Basin in Wyoming. After completing this asset purchase, we increased the capacity of the Pioneer natural gas processing plant from 275 MMcf/d to 550 MMcf/d at an additional cost of approximately $21 million. This expansion was completed in July 2006 and enables us to process natural gas production from the Jonah and Pinedale fields that will be transported to our Wyoming facilities as a result of the contract rights we acquired from TEPPCO. Of the $38.2 million we paid TEPPCO to acquire the Pioneer facility, $37.8 million was allocated to the contract rights we acquired.

After an in-depth consideration of relevant factors, this transaction was approved by the Audit and Conflicts Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO. In addition, each party received a fairness opinion rendered by an independent advisor.

In addition, to handle future production growth in the region, we started construction of a new natural gas processing plant in July 2006 having a capacity of 650 MMcf/d adjacent to the Pioneer plant. We expect our new natural gas processing plant to be placed in service by the third quarter of 2007 at an expected cost of $235 million. As of September 30, 2006, our capital spending with respect to new natural gas processing plant was $20.9 million.

Expansion of Mont Belvieu Petrochemical Assets. In March 2006, we announced an expansion of petrochemical assets in Mont Belvieu and southeast Texas. This expansion project includes (i) the construction of a new propylene fractionator at our Mont Belvieu complex, which will increase our propylene/propane fractionation capacity by approximately 15 MBPD and (ii) the expansion of two refinery grade propylene gathering pipelines which will add 50 MBPD of gathering capacity into Mont Belvieu. These projects are expected to be operational by late 2007 and are expected to cost approximately $205 million, which includes $35 million we spent in December 2005 to acquire a related pipeline asset. As of September 30, 2006, our capital spending with respect to the expansion of our Mont Belvieu petrochemical assets was $95.2 million.

Piceance Basin Gas Processing Project. In January 2006, we announced the execution of a minimum 15-year natural gas processing agreement with an affiliate of EnCana. Under that agreement, we will have the right to process up to 1.3 Bcf/d of EnCana's natural gas production from the Piceance Basin area of western Colorado.

To accommodate this production, we have begun construction of the Meeker natural gas processing facility in Rio Blanco County, Colorado. This processing plant, which will provide us with 750 MMcf/d of natural gas processing capacity and the ability to recover up to 35 MBPD of NGLs at full rates, is expected to be placed in service in mid-2007. In addition, we will construct an approximate 50-mile NGL pipeline that will connect our Meeker facility with our Mid-America Pipeline System. The estimated cost of the Meeker facility and related NGL pipeline is $246 million. We are currently working to secure production dedications from additional producers.

In June 2006, EnCana executed an option which requires us to build a 650 MMcf/d expansion of the Meeker facility by mid-2008. We have initiated design work on this expansion, which is expected to cost $250 million. This expansion will enable us to recover an additional 30 MBPD of NGLs at full rates. Under the terms of the agreement, EnCana has certain guaranteed payment obligations to us.

As of September 30, 2006, our capital spending with respect to our Piceance Basin gas processing projects was $87.3 million.

Hobbs NGL Fractionator. In June 2005, we announced plans to construct a new NGL fractionator, designed to handle up to 75 MBPD of mixed NGLs, located at the interconnection of our Mid-America Pipeline System and our Seminole Pipeline near Hobbs, New Mexico. This project is expected to cost $231 million and be placed in service during the third quarter of 2007. Our Hobbs NGL fractionator will process the increase in mixed NGLs resulting from our Phase I expansion of the Mid-America Pipeline

System. As of September 30, 2006, our capital spending with respect to the Hobbs NGL fractionator was $62.7 million.

Mid-America Pipeline System Projects. In January 2005, we announced an expansion (the Phase I expansion) of the Rocky Mountain segment of our Mid-America Pipeline System to accommodate expected increases in mixed NGL shipments originating from producing basins in Wyoming, Utah, Colorado and New Mexico. The Phase I expansion project will be completed in stages and will increase throughput volumes on the Rocky Mountain segment by 50 MBPD. We expect final completion of the Phase I expansion during the third quarter of 2007 at a cost of approximately $197 million. As of September 30, 2006, our capital spending with respect to the Phase I expansion project was $86.2 million, including accrued expenditures. In August 2006, we executed new long-term transportation agreements with all but one of our current shippers on the Rocky Mountain segment of the Mid-America Pipeline System that will fully utilize this additional capacity.

In June 2005, we began engineering and design work to construct a 190-mile, 12-inch NGL pipeline that will have the capacity to move up to 67 MBPD of mixed NGLs bi-directionally between Skellytown, Texas and Conway, Kansas and an additional 48 MBPD from Skellytown, Texas to Hobbs, New Mexico. Construction of this pipeline began in the spring of 2006 and is expected to cost approximately $83 million and be placed in service in April 2007. As of September 30, 2006, our capital spending with respect to the Skellytown to Conway pipeline was $42.5 million.

Independence Hub Platform and Independence Trail Pipeline System. In November 2004, we entered into an agreement with the Atwater Valley Producers Group for the dedication, processing and gathering of natural gas and condensate production from several natural gas fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas (collectively, the “anchor fields”) of the deepwater Gulf of Mexico. First production is expected in mid-2007.

We are constructing and will own an 80% interest in the Independence Hub platform, which will be located in Mississippi Canyon Block 920, at a water depth of 8,000 feet. The Independence Hub is a 105-foot deep-draft, semi-submersible platform with a two-level production deck, which will process 1 Bcf/d of natural gas. During the third quarter of 2006, we successfully attached the platform topside to the hull and started precommissioning activities. We expect to install the platform during the fourth quarter of 2006 and look for mechanical completion in the first quarter of 2007.

The platform, which is estimated to cost $420 million, will be operated by Anadarko, and is designed to process production from its anchor fields and has excess payload capacity to support ten additional pipeline risers. As of September 30, 2006, our 80% share of capital spending with respect to the Independence Hub platform was $316.5 million.

During the third quarter of 2006, we completed construction of our 134-mile Independence Trail natural gas pipeline system, which has a throughput capacity of 1 Bcf/d of natural gas and will transport production from our Independence Hub platform to the Tennessee Gas Pipeline. This pipeline system and a related junction platform (under construction) are estimated to cost $265 million. As of September 30, 2006, our capital spending with respect to the Independence Trail pipeline and related junction platform was $251.9 million, including accrued expenditures.

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. During the three months ended September 30, 2006, we spent approximately $22.6 million to comply with these programs, of which $7.1 million was recorded as an operating expense and the remaining $15.5 million was capitalized. We spent approximately $54.3 million to comply with these programs during the nine months ended September 30, 2006, of which $21.4 million was recorded as an operating expense and the remaining $32.9 million was capitalized.

We expect our net cash outlay for pipeline integrity program expenditures to approximate $10.4 million for the remainder 2006. Our forecast is net of certain costs we expect to recover from El Paso in connection with an indemnification agreement. In May 2006, we recovered $13.7 million from El Paso related to our 2005 expenditures. We expect to recover $23.4 million for expenditures made during the first nine months of 2006, which leaves a remainder of $13.1 million reimbursable by El Paso for 2006 and 2007 pipeline integrity costs.

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 technology employed) and products produced and/or sold.

We evaluate segment performance based on the non-generally accepted accounting principle (“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 financial measure calculated using accounting principles generally accepted in the United States of America (“GAAP”) 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 (or consolidated) segment gross operating margin as operating income before: 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 expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of changes in accounting principles. 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.

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 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.

For additional information regarding our business segments, please read Note 12 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 presents selected average quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products since the beginning of 2005:

	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)
2005									
1st Quarter	$6.27	$49.68	$0.52	$0.79	$0.98	$1.00	$1.14	$0.45	$0.39
2nd Quarter	$6.74	$53.09	$0.52	$0.82	$0.98	$1.01	$1.16	$0.37	$0.30
3rd Quarter	$8.53	$63.08	$0.69	$0.97	$1.14	$1.26	$1.36	$0.37	$0.33
4th Quarter	$13.00	$60.03	$0.76	$1.06	$1.27	$1.34	$1.36	$0.50	$0.44
Average for Year	$8.64	$56.47	$0.62	$0.91	$1.09	$1.15	$1.26	$0.42	$0.37
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
Average for Year	$7.47	$68.10	$0.67	$1.03	$1.23	$1.28	$1.48	$0.49	$0.43

(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"). The 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, and reflect the periods in which we owned an interest in such operations.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
NGL Pipelines & Services, net:				
NGL transportation volumes (MBPD)	1,740	1,468	1,591	1,463
NGL fractionation volumes (MBPD)	341	270	302	311
Equity NGL production (MBPD) (1)	67	66	63	78
Fee-based natural gas processing (MMcf/d)	2,237	1,471	2,224	1,828
Onshore Natural Gas Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	6,049	6,021	6,066	5,918
Offshore Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	1,573	1,623	1,524	1,876
Crude oil transportation volumes (MBPD)	173	124	149	134
Platform gas treating (Mcf/d)	160	221	158	285
Platform oil treating (MBPD)	12	8	12	8
Petrochemical Services, net:				
Butane isomerization volumes (MBPD)	82	96	83	82
Propylene fractionation volumes (MBPD)	57	55	55	55
Octane additive production volumes (MBPD)	11	8	8	5
Petrochemical transportation volumes (MBPD)	101	50	94	65
Total, net:				
NGL, crude oil and petrochemical transportation volumes (MBPD)	2,014	1,642	1,834	1,662
Natural gas transportation volumes (BBtus/d)	7,622	7,644	7,590	7,794
Equivalent transportation volumes (MBPD) (2)	4,020	3,654	3,831	3,713

(1) Volumes for the first, second and third quarters of 2005 have been revised to incorporate asset-level definitions of equity NGL production volumes.
(2) 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,	
	2006	**2005**	**2006**	**2005**
Revenues	$ 3,872,525	$ 3,249,291	$ 10,640,452	$ 8,476,581
Operating costs and expenses	3,584,783	3,045,345	9,955,231	7,959,122
General and administrative costs	15,823	13,252	45,798	46,655
Equity in income of unconsolidated affiliates	2,265	3,703	14,306	14,563
Operating income	274,184	194,397	653,729	485,367
Interest expense	62,793	60,538	177,203	170,697
Net income	208,302	131,169	468,374	311,084

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,	
	2006	**2005**	**2006**	**2005**
Gross operating margin by segment:				
NGL Pipelines & Services	$ 232,037	$ 153,760	$ 549,401	$ 427,392
Onshore Natural Gas Pipelines & Services	77,489	93,513	260,943	257,774
Offshore Pipelines & Services	38,364	16,922	76,131	62,180
Petrochemical Services	51,851	47,621	136,413	85,559
Total segment gross operating margin	$ 399,741	$ 311,816	$ 1,022,888	$ 832,905

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

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,		For the Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
NGL Pipelines & Services:				
Sale of NGL products	$ 2,640,568	$ 2,218,620	$ 7,276,342	$ 5,680,345
Percent of consolidated revenues	68%	68%	68%	67%
Onshore Natural Gas Pipelines & Services:				
Sale of natural gas	$ 316,273	$ 290,166	$ 954,111	$ 713,692
Percent of consolidated revenues	8%	9%	9%	8%
Petrochemical Services:				
Sale of natural gas	$ 417,395	$ 273,319	$ 1,157,184	$ 899,033
Percent of consolidated revenues	11%	8%	11%	11%

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

Comparison of Three Months Ended September 30, 2006 with Three Months Ended September 30, 2005

Revenues for the third quarter of 2006 were $3.9 billion compared to $3.2 billion for the third quarter of 2005. The quarter-to-quarter increase in consolidated revenues is primarily due to higher sales volumes and energy commodity prices in the third quarter of 2006 relative to the same period in 2005. These differences accounted for a $592.1 million increase in consolidated revenues associated with our marketing activities. Revenues for the third quarter of 2006 include $50.2 million of proceeds from business interruption insurance associated with Hurricanes Katrina and Rita in 2005 and Hurricane Ivan in 2004.

Operating costs and expenses were $3.6 billion for the third quarter of 2006 versus $3 billion for the third quarter of 2005. The quarter-to-quarter increase in consolidated operating costs and expenses is primarily due to an increase in the cost of sales associated with our marketing activities. The cost of sales of our natural gas, NGL and petrochemical products increased $383.9 million quarter-to-quarter as a result of higher energy commodity prices. Operating costs and expenses associated with our South Louisiana natural gas processing plants increased $103 million attributable to higher processing volumes in the third quarter of 2006 relative to the same quarter in 2005.

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 during the third quarter of 2006 versus $0.98 per gallon during the third quarter of 2005—a quarter-to-quarter increase of 11%. 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 hub of the domestic NGL industry. The market price of natural gas (as measured at Henry Hub in Louisiana) averaged $6.58 per MMBtu during the third quarter of 2006 versus $8.53 per MMBtu during the third quarter of 2005. For additional historical energy commodity pricing information, please see the table on page 55.

Equity earnings from unconsolidated affiliates were $2.3 million for the third quarter of 2006 compared to $3.7 million for the third quarter of 2005. Equity earnings from our investment in Neptune Pipeline Company, L.L.C. (“Neptune”) decreased $6.7 million quarter-to-quarter. The third quarter of 2006 includes a $7.4 million non-cash impairment charge associated with our investment in Neptune. Collectively, equity earnings from Poseidon Oil Pipeline, L.L.C. (“Poseidon”) and Deepwater Gateway, L.L.C. (“Deepwater Gateway”) increased $4.3 million quarter-to-quarter due to increased production activity.

Operating income for the third quarter of 2006 was $274.2 million compared to $194.4 million for the third quarter of 2005. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $79.8 million increase in operating income quarter-to-quarter.

Interest expense increased $2.3 million quarter-to-quarter. Although outstanding debt balances and interest rates were higher during the third quarter of 2006 relative to the third quarter of 2005, significant amounts of interest are being capitalized as a result of borrowings to finance our capital spending program. Capitalized interest amounts were $15 million for the third quarter of 2006 compared to $4.6 million for the third quarter of 2005.

As a result of the items noted in previous paragraphs, our consolidated net income increased $77.1 million to $208.3 million for the third quarter of 2006 compared to $131.2 million for the third quarter of 2005.

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

NGL Pipelines & Services. Gross operating margin from this business segment was $232 million for the third quarter of 2006 compared to $153.8 million for the third quarter of 2005. Proceeds from business interruption insurance received during the third quarter of 2006 accounted for $30.1 million of the increase in gross operating margin. Strong demand for NGLs in the third quarter of 2006 compared to the third quarter of 2005 led to higher processing margins, increased volumes processed under fee-based contracts and higher throughput volumes at certain of our pipelines and NGL fractionation facilities.

Gross operating margin from our natural gas processing and related NGL marketing business, excluding proceeds from business interruption insurance, was $107.9 million for the third quarter of 2006 compared to $97.5 million for the same quarter in 2005. The $10.4 million increase in gross operating margin quarter-to-quarter is largely due to strong demand for NGLs during the third quarter of 2006. Fee-based processing volumes increased to 2.2 Bcf/d during the third quarter of 2006 from 1.5 Bcf/d during the third quarter of 2005. Lastly, gross operating margin from natural gas processing for the third quarter of 2006 includes $3.7 million from the Pioneer plant we acquired from TEPPCO in March 2006.

Gross operating margin from NGL fractionation, excluding proceeds from business interruption insurance, was $37.4 million for the third quarter of 2006 compared to $12.8 million for the third quarter of 2005. Fractionation volumes increased from 270 MBPD during the third quarter of 2005 to 341 MBPD during the third quarter of 2006. The quarter-to-quarter increase in gross operating margin is largely due to increased fractionation volumes at our Norco and Mont Belvieu NGL fractionators. These facilities suffered a reduction of volumes in the third quarter of 2005 due to Hurricanes Katrina and Rita. Also, our Mont Belvieu NGL fractionator benefited from a 15 MBPD expansion project that was completed during the second quarter of 2006.

Gross operating margin from NGL pipelines and storage, excluding proceeds from business interruption insurance, was $56.6 million for the third quarter of 2006 compared to $43.4 million for the third quarter of 2005. Total NGL transportation volumes increased to 1,740 MBPD during the third quarter of 2006 from 1,468 MBPD during the same quarter of 2005. The $13.2 million quarter-to-quarter increase in gross operating margin is attributable to higher NGL transportation and storage volumes at certain of our facilities and the affects of a higher average transportation rate charged to shippers on our Mid-America pipeline.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $77.5 million for the third quarter of 2006 compared to $93.5 million for the third quarter of 2005. Collectively, gross operating margin from our Acadian Gas System and Petal natural gas storage facility decreased $11.9 million quarter-to-quarter due to lower natural gas sales margins and demand for natural gas storage during the third quarter of 2006 versus the same quarter in 2005. Natural gas supply interruptions in South Louisiana resulting from Hurricane Katrina led to higher natural gas sales margins and demand for storage services during the third quarter of 2005. Also, gross operating margin from this segment decreased $9.4 million quarter-to-quarter as a result of mechanical problems associated with three storage caverns at our Wilson natural gas storage facility in Texas. This includes a $6.6 million charge for an accrued loss associated with the withdrawal of cushion gas during the third quarter of 2006 at lower realized natural gas prices compared to the higher contracted prices for natural gas volumes that are expected to be re-injected in the first half of 2007 when the caverns return to service.

Segment gross operating margin from our Texas Intrastate System increased $5.4 million to $28.2 million for the third quarter of 2006 from $22.8 million for the third quarter of 2005. Our Texas Intrastate System benefited from lower natural gas purchase costs quarter-to-quarter. The third quarter of 2006 includes $1.1 million of gross operating margin from the Encinal natural gas gathering system we acquired in July 2006. Natural gas transportation volumes for the Encinal natural gas gathering system were 95 BBtu/d for the third quarter of 2006. Our total onshore natural gas transportation volumes were 6,049 BBtu/d during the third quarter of 2006 compared to 6,021BBtu/d for the third quarter of 2005.

Offshore Pipelines & Services. Gross operating margin from this business segment was $38.4 million for the third quarter of 2006 compared to $16.9 million for the third quarter of 2005. Segment gross operating margin for the third quarter of 2006 includes $20.1 million of proceeds from business interruption insurance claims related to Hurricanes Katrina and Rita in 2005 and Hurricane Ivan in 2004. As a result of industry losses associated with these storms, insurance costs for offshore operations have increased dramatically. Insurance costs for our offshore assets were $6.2 million for the third quarter of 2006 compared to $2 million for the third quarter of 2005.

Gross operating margin from our offshore crude oil pipelines was $8.8 million for the third quarter of 2006 versus $1.2 million for the third quarter of 2005. Our Marco Polo and Poseidon oil pipelines posted higher crude oil transportation volumes during the third quarter of 2006 due to increased production activity. Collectively, gross operating margin from the Marco Polo and Poseidon oil pipelines improved $4.3 million quarter-to-quarter. Our Constitution Oil Pipeline, which was placed in-service during the first quarter of 2006, contributed $3 million to segment gross operating margin during the third quarter of 2006. Total offshore crude oil transportation volumes were 173 MBPD during the third quarter of 2006 versus 124 MBPD during the third quarter of 2005.

Gross operating margin from our offshore natural gas pipelines, excluding proceeds from business interruption insurance, was $1 million for the third quarter of 2006 compared to $4.9 million for the third quarter of 2005. Offshore natural gas transportation volumes were 1,573 BBtu/d during the third quarter of 2006 versus 1,623 BBtu/d during the third quarter of 2005. Gross operating margin for the third quarter of 2006 includes a non-cash impairment charge of $7.4 million associated with our investment in Neptune. The third quarter of 2006 includes gross operating margin of $4 million and transportation volumes of 94 BBtu/d from the Constitution natural gas pipeline, which was placed in service during the first quarter of 2006. Also, during the third quarter of 2006, we continue to make significant progress on our Independence Hub and Trail project. We expect to complete the installation of the platform and begin receiving demand charges in the first quarter of 2007. First production is expected late in the second quarter of 2007, at which time we will begin receiving commodity fees for our platform processing and gathering services.

Gross operating margin from our offshore platforms, excluding proceeds from business interruption insurance, was $8.6 million for the third quarter of 2006 compared to $10.8 million for the third quarter of 2005. The decrease in gross operating margin quarter-to-quarter is primarily due to reduced production attributable to last year’s hurricanes. Equity earnings from Deepwater Gateway, which owns the Marco Polo platform, increased $2 million quarter-to-quarter primarily due to higher processing volumes.

Petrochemical Services. Gross operating margin from this business segment was $51.9 million for the third quarter of 2006 compared to $47.6 million for the third quarter of 2005. The $4.3 million quarter-to-quarter increase in gross operating margin is primarily due to improved results from our octane enhancement business. Gross operating margin from this business was $18.4 million for the third quarter of 2006 compared to $14.2 million for the third quarter of 2005. The $4.2 million quarter-to-quarter increase is primarily attributable to higher isooctane sales volumes. Isooctane, a high octane, low vapor pressure motor gasoline additive, complements the increasing use of ethanol, which has a high vapor pressure. Our isooctane production facility commenced operations in the second quarter of 2005.

Gross operating margin from our propylene fractionation and pipeline activities was $14.9 million for the third quarter of 2006 versus $12.6 million for the third quarter of 2005. The quarter-to-quarter increase in gross operating margin of $2.3 million is primarily due to improved results from our Lou-Tex propylene pipeline and the addition of the Texas City refinery-grade propylene pipeline, which we completed during 2005. Petrochemical transportation volumes were 101 MBPD during the third quarter of 2006 compared to 50 MBPD during the third quarter of 2005.

Gross operating margin from butane isomerization was $18.5 million for the third quarter of 2006 compared to $20.8 million for the third quarter of 2005. The quarter-to-quarter decrease of $2.3 million is primarily due to lower processing volumes. Butane isomerization volumes were 82 MBPD during the third quarter of 2006 compared to 96 MBPD during the third quarter of 2005.

Comparison of Nine Months Ended September 30, 2006 with Nine Months Ended September 30, 2005

Revenues for the first nine months of 2006 were $10.6 billion compared to $8.5 billion for the first nine months of 2005. The period-to-period increase in consolidated revenues is primarily due to higher sales volumes and energy commodity prices during the first nine months of 2006 relative to the 2005 period. These differences accounted for a $2.1 billion increase in consolidated revenues associated with our marketing activities. Revenues for the first nine months of 2006 include $62.4 million of proceeds from business interruption insurance associated with Hurricanes Katrina and Rita in 2005 and Hurricane Ivan in 2004.

Operating costs and expenses were $10 billion for the first nine months of 2006 compared to $8 billion for the first nine months of 2005. The period-to-period increase in consolidated operating costs and expenses is primarily 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 $1.8 billion period-to-period as a result of higher energy commodity prices. Operating costs and expenses associated with our South Louisiana natural gas processing plants increased $119.7 million attributable to higher processing activity and energy commodity prices during the first nine months of 2006 relative to the same period in 2005.

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 $1.02 per gallon for the nine months ended September 30, 2006 versus $0.86 per gallon during the first nine months of 2005—a period-to-period increase of 19%. The Henry Hub market price for natural gas averaged $7.47 per MMBtu for the nine months ended September 30, 2006 versus $7.18 per MMBtu during the 2005 period. For additional historical energy commodity pricing information, please see the table on page 55.

Equity earnings from unconsolidated affiliates were $14.3 million for the first nine months of 2006 versus $14.6 million for the first nine months of 2005. Equity earnings from Neptune for the first nine months of 2006 include a non-cash impairment charge of $7.4 million. Collectively, equity earnings from Poseidon and Deepwater Gateway increased $7.3 million period-to-period due to increased production activity. Equity earnings for Cameron Highway increased $6.8 million period-to-period. The first nine months of 2005 include a one-time charge of $11.5 million for costs associated with the refinancing of Cameron Highway's project finance debt. Also, the first nine months of 2005 includes a $5.1 million benefit associated with the settlement of a transportation contract dispute.

Interest expense increased to $177.2 million for the first nine months of 2006 from $170.7 million for the first nine months of 2005. Although outstanding debt balances and interest rates were higher during the first nine months of 2006 relative to the 2005 period, significant amounts of interest are being capitalized as a result of borrowings to finance our capital spending program. Capitalized interest amounts were $36.6 million for the first nine months of 2006 compared to $12.2 million for the first nine months of 2005. Provision for income taxes increased $8.5 million period-to-period primarily due to the new Texas margin tax. For more information regarding the Texas Margin Tax, please see "*Other Items*" included within this Item 2.

As a result of the items noted in previous paragraphs, our consolidated net income increased $157.3 million to $468.4 million for the nine months ended September 30, 2006 compared to $311.1 million for the 2005 period. The first nine months of 2006 includes 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.

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 $549.4 million for the first nine months of 2006 compared to $427.4 million for the first nine months of 2005. Our receipt of business interruption insurance proceeds during the third quarter of 2006 accounted for $40.4 million of the increase in gross operating margin period-to-period. Strong demand for NGLs during the first nine months of 2006 relative to the first nine months of 2005 led to higher processing margins, increased volumes processed under fee-based contracts and higher throughput volumes on all of our NGL pipelines.

Gross operating margin from our natural gas processing and related NGL marketing business, excluding proceeds from business interruption insurance, was $268.9 million for the first nine months of 2006 compared to $236.9 million for the first nine months of 2005. The $32 million increase in gross operating margin period-to-period is largely due to strong demand for NGLs during the first nine months of 2006 relative to the same period in 2005. Fee-based processing volumes increased to 2.2 Bcf/d during the first nine months of 2006 from 1.8 Bcf/d during the first nine months of 2005. Lastly, gross operating margin from natural gas processing for the first nine months of 2006 includes $6 million from the Pioneer plant we acquired from TEPPCO in March 2006.

Gross operating margin from NGL pipelines and storage, excluding proceeds from business interruption insurance, was $175.7 million for the first nine months of 2006 compared to $143.9 million for the first nine months of 2005. Total NGL transportation volumes increased to 1,591 MBPD for the first nine months of 2006 from 1,463 MBPD for the first nine months of 2005. The $31.8 million period-to-period increase in gross operating margin is attributable to higher pipeline transportation, NGL storage and export volumes at certain of our facilities and contributions from acquired or consolidated assets, particularly that generated by the Dixie NGL Pipeline. The increase in gross operating margin was partially offset by a $4.3 million increase in pipeline integrity costs period-to-period.

Gross operating margin from NGL fractionation, excluding proceeds from business interruption insurance, was $64.4 million for the first nine months of 2006 compared to $46.7 million for the first nine months of 2005. Of the $17.7 million increase in gross operating margin period-to-period, $10.8 million of the increase is attributable to our Mont Belvieu NGL fractionation facility and $6 million is attributable to our Norco facility. Results from our Mont Belvieu facility for the first nine months of 2006 include $6.7 million of operating and blending gains compared to $4.3 million of operating and blending losses during the same period in 2005, which results in a positive variance of $11 million period-to-period. Our Norco facility benefited from higher processing fees during the first nine months of 2006 versus the first nine months of 2005.

As noted in our discussion of quarter-to-quarter results for NGL fractionation, volumes for the third quarter of 2006 were 71 MBPD higher than those for the third quarter of 2005, which were reduced due to the effects of Hurricanes Katrina and Rita. Despite increased volumes for the third quarter of 2006, NGL fractionation volumes for the first nine months of 2006 were 302 MBPD compared to 311 MBPD during the first nine months of 2005.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $260.9 million for the first nine months of 2006 compared to $257.8 million for the first nine months of 2005. Higher transportation revenues on our Texas Intrastate System contributed to a $15.8 million increase in segment gross operating margin period-to-period. An increase in drilling activity in the Permian and San Juan basins benefited our assets during the first nine months of 2006. Our gathering systems in the Permian basin experienced higher transportation volumes and natural gas sales margins period-to-period. Collectively, gross operating margin from our San Juan and Permian basin gathering systems increased $7.5 million period-to-period. Also, segment gross operating margin for the first nine months of 2006 includes $1.1 million from the Encinal natural gas gathering system we acquired in July 2006. Our total onshore natural gas transportation volumes were 6,066 BBtu/d during the first nine months of 2006 compared to 5,918 BBtu/d during the first nine months of 2005.

Gross operating margin from our natural gas storage business was $14.3 million for the first nine months of 2006 compared to $31.1 million for the first nine months of 2005. The period-to-period decrease in gross operating margin is largely due to lower storage revenues and higher operating costs attributable to mechanical problems associated with three storage caverns at our Wilson natural gas storage facility in Texas.

Offshore Pipelines & Services. Gross operating margin from this business segment was $76.1 million for the first nine months of 2006 compared to $62.2 million for the first nine months of 2005. Segment gross operating margin for the first nine months of 2006 includes $22 million of proceeds from business interruption insurance. As a result of industry losses last year, insurance costs for offshore operations have increased dramatically. Our insurance costs for the first nine months of 2006 increased $9.3 million over those recorded during the first nine months of 2005.

Gross operating margin from our offshore crude oil pipelines was a positive $16.2 million for the first nine months of 2006 versus a loss of $2.4 million for the first nine months of 2005. Our Marco Polo and Poseidon oil pipelines posted higher crude oil transportation volumes during the first nine months of 2006 due to increased production activity. Collectively, gross operating margin from these pipelines improved $5.8 million period-to-period. Our Constitution oil pipeline, which was placed in-service during the first quarter of 2006, contributed $6.4 million to segment gross operating margin during the first nine months of 2006. Gross operating margin from Cameron Highway improved $6.8 million period-to-period. Cameron Highway's results for the first nine months of 2005 included a one-time charge of $11.5 million for costs associated with the refinancing of its project finance debt. Offshore crude oil transportation volumes were 149 MBPD during the first nine months of 2006 versus 134 MBPD during the first nine months of 2005.

Gross operating margin from our offshore natural gas pipelines, excluding proceeds from business interruption insurance, was $14.6 million for the first nine months of 2006 compared to $32.3 million for the first nine months of 2005. Offshore natural gas transportation volumes were 1,524 BBtu/d during the first nine months of 2006 versus 1,876 BBtu/d during the first nine months of 2005. The $17.7 million decrease in gross operating margin and overall transportation volumes is due in part to last year's hurricanes. Gross operating margin for the first nine months of 2006 includes a non-cash impairment charge of $7.4 million associated with our investment in Neptune. Also, gross operating margin attributable to this group of assets for the first nine months of 2005 includes a one-time $5.1 million benefit resulting from the settlement of a transportation contract dispute. Gross operating margin for the first nine months of 2006 includes $6.1 million from the Constitution natural gas pipeline, which was placed in service during the first quarter of 2006.

Gross operating margin from our offshore platforms and services business, excluding proceeds from business interruption insurance, was $23.4 million for the first nine months of 2006 compared to $32.2 million for the first nine months of 2005. The decrease in gross operating margin period-to-period is primarily due to last year's hurricanes. Equity earnings from Deepwater Gateway increased $5.5 million period-to-period primarily due to higher processing volumes on the Marco Polo platform.

Petrochemical Services. Gross operating margin from this business segment was $136.4 million for the first nine months of 2006 compared to $85.6 million for the first nine months of 2005. The $50.8 million period-to-period increase in gross operating margin is primarily due to improved results from our octane enhancement business. Gross operating margin from this business was a positive $27.8 million for the first nine months of 2006 compared to a loss of $0.9 million for the first nine months of 2005. The $28.7 million period-to-period increase is primarily attributable to higher isooctane sales volumes, particularly during the second quarter of 2006. Also, our isooctane production facility commenced operations in the second quarter of 2005.

Gross operating margin from propylene fractionation was $51.5 million for the first nine months of 2006 versus $34.8 million for the first nine months of 2005. The period-to-period increase in gross operating margin of $16.7 million is primarily due to higher propylene sales margins and pipeline transportation volumes. Petrochemical transportation volumes were 94 MBPD during the first nine months of 2006 compared to 65 MBPD during the first nine months of 2005.

Gross operating margin from butane isomerization was $57.1 million for the first nine months of 2006 compared to $51.6 million for the first nine months of 2005. The period-to-period increase of $5.5 million is largely due to increased demand for motor gasoline additives.

Significant Risks and Uncertainties – Hurricanes

EPCO renewed its property and casualty insurance programs during the second quarter of 2006. As a result of severe hurricanes such as Katrina and Rita that occurred in 2005, market conditions for obtaining property damage insurance coverage were difficult. Under our renewed insurance programs, coverage is more restrictive, including increased physical damage and business interruption deductibles. For example, our deductible for onshore physical damage increased from $2.5 million to $5 million per event and our deductible period for onshore business interruption claims increased from 30 days to 60 days. Additional restrictions will also be applied in the event of damage from named windstorms.

In addition to changes in coverage, the cost of property damage insurance increased substantially from prior periods. At present, our annualized cost of insurance premiums for all lines of coverage is approximately $49.2 million, which represents a $28.1 million (or 133%) increase from our 2005 annualized insurance cost.

The following is a discussion of the general status of insurance claims related to significant storm events that affected our assets in 2004 and 2005. To the extent we include estimates regarding the dollar value of damages, please be aware that a change in our estimates may occur as additional information becomes available to us.

Hurricane Ivan insurance claims. Our final purchase price allocation related to the merger of GulfTerra with a wholly owned subsidiary of Enterprise Products Partners in September 2004 (the "GulfTerra Merger") included a $26.2 million receivable for insurance claims related to expenditures to repair property damage to certain pre-merger GulfTerra assets caused by Hurricane Ivan. During the first nine months of 2006, we received cash reimbursements from insurance carriers totaling $24.1 million related to these property damage claims, and we expect to recover the remaining $2.1 million in late 2006. If the final recovery of funds is different than the amount previously expended, we will recognize an income impact at that time.

In addition, we have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan. During the first nine months of 2006, we received claim proceeds of $17.4 million. To the extent we receive cash proceeds from business interruption insurance claims, they are recorded as a gain in our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income in the period of receipt.

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. Repair of property damage to our facilities is continuing. To the extent that insurance proceeds from property damage claims do not cover our estimated recoveries (in excess of the $5 million of insurance deductibles we expensed during the third quarter of 2005), such shortfall will be charged to earnings when realized. We recorded $81.4 million of estimated recoveries from property damage claims arising from Hurricanes Katrina and Rita, based on amounts expended through September 30, 2006. During the first nine months of 2006, we received $9.7 million of physical damage proceeds.

In addition, during the first nine months of 2006 we received $45.1 million of business interruption proceeds. To the extent we receive cash proceeds from business interruption claims, they are recorded as a gain in our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income in the period of receipt. We estimate that up to $25 million of additional business interruption proceeds could be received by the end of 2007. Such additional amounts are subject to the review and concurrence of our insurers. Reviews of the outstanding claims are ongoing.

The following table summarizes our cash receipts with respect to business interruption and property damage proceeds for Hurricanes Ivan, Katrina and Rita for the periods indicated.

	For The Three Months Ended September 30, 2006	For The Nine Months Ended September 30, 2006
Business interruption proceeds:		
Hurricane Ivan	$ 5,157	$ 17,383
Hurricane Katrina	24,325	24,325
Hurricane Rita	20,740	20,740
Total proceeds	$ 50,222	$ 62,448
Property damage proceeds:		
Hurricane Ivan		$ 24,104
Hurricane Katrina	$ 6,975	6,975
Hurricane Rita	2,730	2,730
Total	$ 9,705	$ 33,809

LIQUIDITY AND CAPITAL RESOURCES

Our primary cash requirements, in addition to normal operating expenses and debt service, are for 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 cash flows from operating activities, borrowings under commercial bank credit facilities and the issuance of additional equity and debt securities. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

At September 30, 2006, we had $117.4 million of unrestricted cash on hand and approximately $1.3 billion of available credit under our Operating Partnership's Multi-Year Revolving Credit Facility. We had approximately $4.9 billion in principal outstanding under various consolidated debt obligations at September 30, 2006.

As a result of our growth objectives, we expect to access debt and equity capital markets from time-to-time and we believe that financing arrangements to support our growth activities can be obtained on reasonable terms. Furthermore, we believe that maintenance of an investment grade credit rating combined with continued ready access to debt and equity capital at reasonable rates and sufficient trade credit to operate our businesses efficiently provide a solid foundation to meet our long and short-term liquidity and capital resource requirements.

For additional information regarding our growth strategy, please read “*Capital Spending*” included within this Item 2.

Credit Ratings

At November 1, 2006, the credit ratings of our Operating Partnership's senior unsecured debt securities were Baa3 with a stable outlook as rated by Moody's Investor Services; BBB- with a stable outlook as rated by Fitch Ratings; and BB+ with a positive outlook as rated by Standard and Poor's.

Based on the characteristics of the fixed/floating unsecured junior subordinated notes that the Operating Partnership issued during the third quarter of 2006, the rating agencies assigned partial equity treatment to the notes. Moody's Investor Services and Standard and Poor's each assigned 50% equity treatment and Fitch Ratings assigned 75% equity treatment.

Registration Statements and Equity and Debt Offerings

From time-to-time, we issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. We have a universal shelf registration statement on file with the U.S. Securities and Exchange Commission ("SEC") registering the issuance of up to $4 billion of equity and debt securities. After taking into account the past issuance of securities under this universal registration statement, we can issue approximately $2.1 billion of additional securities under this registration statement as of November 1, 2006.

In March 2006, we sold 18,400,000 common units (including an over-allotment amount of 2,400,000 common units) to the public at an offering price of $23.90 per unit. Net proceeds from this offering, including Enterprise Products GP's proportionate net capital contribution of $8.6 million, were approximately $430 million after deducting applicable underwriting discounts, commissions and estimated offering expenses of $18.3 million. The net proceeds from this offering, including Enterprise Products GP's proportionate net capital contribution, were used to temporarily reduce indebtedness outstanding under our Operating Partnership's Multi-Year Revolving Credit Facility.

During the third quarter of 2006, the Operating Partnership sold $550 million in principal amount of fixed/floating unsecured junior subordinated notes (the "Junior Notes A"). The Operating Partnership used the proceeds from these issuances to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. The Junior Notes A mature in August 2066 and bear interest from July 2006 to August 2016 at an annual rate of 8.375%, and thereafter at an annual rate equal to the 3-month LIBOR rate for the related interest period plus 3.708%.

In July 2006, we issued approximately 7.1 million of our common units in connection with the Encinal business acquisition. In August 2006, we filed a registration statement with the SEC for the resale of these common units. Please read "*Capital Spending*" included within this Item 2 for additional information regarding this business combination.

In September 2006, we sold 12,650,000 common units (including an over-allotment amount of 1,650,000 common units) to the public at an offering price of $25.80 per unit. Net proceeds from this offering, including Enterprise Products GP's proportionate net capital contribution of $6.4 million, were approximately $320.8 million after deducting applicable underwriting discounts, commissions and estimated offering expenses of $11.8 million. Net proceeds of $260 million from this offering, including Enterprise Products GP's proportionate net capital contribution, were used to temporarily reduce indebtedness outstanding under our Operating Partnership's Multi-Year Revolving Credit Facility. The remaining net proceeds were used for general partnership purposes.

During the first nine months of 2006, we issued 3,306,436 common units in connection with the our distribution reinvestment plan, or DRP, and related employee unit purchase program, which generated aggregate proceeds of $84.4 million. These proceeds include $50 million reinvested by EPCO in August 2006 with respect to its beneficial ownership of our common units. A total of 1,966,354 common units were issued to EPCO as a result of this reinvestment in our partnership.

Debt Obligations

Consolidated debt obligations. For detailed information regarding our consolidated debt obligations and those of our unconsolidated affiliates, please read Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report. The following table summarizes our consolidated debt obligations at the dates indicated (dollars in thousands):

	September 30, 2006	December 31, 2005
Operating Partnership debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due October 2011 (1)		$ 490,000
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	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
Dixie Revolving Credit Facility, variable rate, due June 2010 (2)	10,000	17,000
Debt obligations assumed from GulfTerra	5,068	5,068
Total principal amount of senior debt obligations	4,369,068	4,866,068
Junior Notes A, due August 2066	550,000	
Total principal amount of senior and junior debt obligations	4,919,068	4,866,068
Other, including unamortized discounts and premiums and changes in fair value (3)	(34,807)	(32,287)
Long-term debt	$ 4,884,261	$ 4,833,781
Standby letters of credit outstanding	$ 53,158	$ 33,129

(1) In June 2006, the Operating Partnership executed a second amendment (the “Second Amendment”) to the credit agreement governing its Multi-Year Revolving Credit Facility. The Second Amendment, among other things, extends the maturity date of amounts borrowed under the Multi-Year Revolving Credit Facility from October 2010 to October 2011 with respect to $1.2 billion of the commitments. Borrowings with respect to the remaining $48 million in commitments mature in October 2010.

(2) The maturity date of this facility was extended from June 2007 to June 2010 in August 2006. The other terms of the Dixie facility remain unchanged from those described in our annual report on Form 10-K for the year ended December 31, 2005.

(3) The September 30, 2006 amount includes $21.3 million related to fair value hedges and $13.5 million in net unamortized discounts. The December 31, 2005 amount includes $18.2 million related to fair value hedges and $14.1 million in net unamortized discounts.

Issuance of Junior Notes A. The Operating Partnership sold $550 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due 2066 (“Junior Notes A”) during the third quarter of 2006. The Operating Partnership used the proceeds from issuing this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. The Operating Partnership’s payment obligations under Junior Notes A are subordinated to all of its current and future senior indebtedness (as defined in the Indenture Agreement). Enterprise Products Partners has guaranteed repayment of amounts due under Junior Notes A through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Notes A allows the Operating Partnership to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. The indenture agreement also provides that, unless (i) all deferred interest on Junior Notes A has been paid in full as of the most recent interest payment date, (ii) no event of default under the Indenture has occurred and is continuing and (iii) Enterprise Products Partners is not in default of its obligations under related guarantee agreements, then the Operating Partnership and Enterprise Products Partners cannot declare or make any distributions with respect to any of their respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or subordinate to Junior Notes A.

The Junior Notes A will bear interest at a fixed annual rate of 8.375% from July 2006 to August 2016, payable semi-annually in arrears in February and August of each year, commencing in February 2007. After August 2016, the Junior Notes A will bear variable rate interest at an annual rate equal to the 3-month LIBOR rate for the related interest period plus 3.708%, payable quarterly in arrears in February, May, August and November of each year commencing in November 2016. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to the certain provisions. The Junior Notes A mature in August 2066 and are not redeemable by the Operating Partnership prior to August 2016 without payment of a make-whole premium.

In connection with the issuance of Junior Notes A, the Operating Partnership entered into a Replacement Capital Covenant in favor of the covered debt holders (as named therein) pursuant to which the Operating Partnership agreed for the benefit of such debt holders that it would not redeem or repurchase such junior notes unless such redemption or repurchase is made from the proceeds of issuance of certain securities.

Based on the characteristics of the fixed/floating unsecured junior subordinated notes that the Operating Partnership issued during the third quarter of 2006, the rating agencies assigned partial equity treatment to the notes. Moody’s Investor Services and Standard and Poor’s each assigned 50% equity treatment and Fitch Ratings assigned 75% equity treatment.

Debt obligations of unconsolidated affiliates. The following table summarizes the debt obligations of our unconsolidated affiliates (on a 100% basis to the joint venture) at September 30, 2006 and our ownership interest in each entity on that date (dollars in thousands):

	Our Ownership Interest	**Total**
Cameron Highway Oil Pipeline Company (“Cameron Highway”)	50.0%	$ 415,000
Poseidon Oil Pipeline Company, L.L.C. (“Poseidon”)	36.0%	92,000
Evangeline Gas Pipeline Company, L.P.	49.5%	30,650
Total		$ 537,650

In March 2006, Cameron Highway amended the note purchase agreement governing its senior secured notes to primarily address the effect of reduced deliveries of crude oil to Cameron Highway resulting from production delays caused by the lingering effects of Hurricanes Katrina and Rita. In general, this amendment modified certain financial covenants in light of production forecasts. In addition, the amendment increased the letters of credit required to be issued by the Operating Partnership and an affiliate of our joint venture partner from $18.4 million each to $36.8 million each.

In September 2006, Fitch Ratings reaffirmed its BBB- rating (with a negative outlook) of Cameron Highway’s privately placed senior secured notes. The rating was placed on watch in March 2006 due to the near-term financial impact of lower than anticipated volumes on the Cameron Highway Oil Pipeline. While Fitch continues to believe that the current volume shortfalls are temporary, particularly with completion of the Atlantis development expected in the first quarter of 2007, if transportation volumes remain impaired over the next several months Fitch will likely lower the rating. If the rating falls below BBB-, the interest costs paid by Cameron Highway will increase from 1% to 1.5% per annum depending on the lower rating.

In May 2006, Poseidon amended its revolving credit facility, which, among other things, decreased the availability to $150 million from $170 million, extended the maturity date from January 2008 to May 2011 and lowered the borrowing rate.

Cash Flows from Operating, Investing and Financing Activities

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

	For the Nine Months Ended September 30,	
	2006	2005
Net cash provided from operating activities	$ 986,024	$ 344,633
Net cash used in investing activities	1,217,238	881,864
Net cash provided by financing activities	306,516	545,363

Net cash provided from operating activities is 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.

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

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

Comparison of Nine Months Ended September 30, 2006 with Nine Months Ended September 30, 2005

Operating activities. Net cash provided from operating activities was $986 million for the first nine months of 2006 compared to $344.6 million for the first nine months of 2005, an increase of $641.4 million period-to-period. In addition to changes in our earnings and other factors as described below, cash flows from operating activities are influenced by the timing of cash disbursements and cash receipts between periods. The following information highlights other factors that attributed to the period-to-period change in cash flows provided by operating activities:

§ Gross operating margin increased $190 million period-to-period to approximately $1 billion for the first nine months of 2006 versus $832.9 million for the same period in 2005. Gross operating margin for the first nine months of 2006 includes $62.4 million of cash proceeds from business interruption insurance claims. The increase in gross operating margin period-to-period is discussed under “Results of Operations” within this Item 2.

§ Inventories increased by $384.1 million during the first nine months of 2005 versus $11 million during the first nine months of 2006. Increases or decreases in inventory are influenced by changes in commodity prices and our marketing activities.

§ Cash distributions received from unconsolidated affiliates decreased $20.3 million period-to-period primarily due to (i) a $3 million decrease in cash distributions from our investment in Venice Energy Services Company, LLC resulting from facility downtime and repair costs caused by damage inflicted by Hurricane Katrina, (ii) our receipt of a $5.1 million cash distribution from Neptune in the second quarter of 2005 associated with the resolution of a transportation contract dispute, (iii) our receipt of a special distribution of $11.6 million from Deepwater Gateway in

March 2005 in connection with the repayment of its term loan and (iv) a $1.1 million decrease in cash distributions from our investment in Coyote Gas Treating, LLC, which was sold to a third party in August 2006.

§ Cash payments for interest were $201.9 million for the first nine months of 2006 compared to $190.9 million for the first nine months of 2005.

Investing activities. Cash used in investing activities was $1.2 billion for the first nine months of 2006 compared to $881.9 million for the first nine months of 2005. Expenditures for growth and sustaining capital projects (net of contributions in aid of construction costs) increased $350.9 million period-to-period primarily due to cash payments associated with our projects in the Rocky Mountains and Gulf of Mexico. For additional information regarding our capital spending program, please read " – Capital Spending" included within this Item 2.

Our cash outlays for asset purchases and business combinations were $183.2 million for the first nine months of 2006 versus $325.1 million for the first nine months of 2005. During the first nine months of 2006, we acquired the Pioneer processing plant from TEPPCO for $38.2 million and paid Lewis $145 million in cash in connection with the Encinal acquisition. Our cash outlay for acquisitions during the first nine months of 2005 included (i) $144 million for storage assets purchased from Ferrellgas LP, (ii) $74.9 million for indirect interests in certain East Texas natural gas gathering and processing assets, (iii) $68.6 million for additional ownership interests in Dixie and (iv) $25 million for the remaining ownership interests in our Mid-America Pipeline System and Seminole Pipeline.

Proceeds from the sale of assets during the first nine months of 2005 include $42.1 million from the sale of our investment in Starfish Pipeline Company, LLC. We were required to divest our ownership interest in this entity by the Federal Trade Commission in order to gain its approval for our merger with GulfTerra Energy Partners, L.P. in September 2004. In addition, we received $47.5 million as a return of our investment in Cameron Highway in June 2005. As a result of refinancing its project debt, Cameron Highway was authorized by its lenders to make this special distribution.

Investments in unconsolidated affiliates were $100.3 million for the first nine months of 2006 compared to $80.8 million for the first nine months of 2005. The 2006 period includes $83.3 million we invested to date in the Phase V expansion project of Jonah. The 2005 period primarily reflects $72 million we contributed to Deepwater Gateway to fund our share of the repayment of its construction loan in March 2005.

Financing activities Cash provided by financing activities was $306.5 million for the first nine months of 2006 compared to $545.4 million for the first nine months of 2005. We had net borrowings under our debt agreements of $61.3 million during the 2006 period versus $522.3 million during the 2005 period. As a result of our capital spending program, we utilized the Operating Partnership's Multi-Year Revolving Credit Facility in varying degrees throughout the first nine months of 2006. At September 30, 2006, we had temporarily repaid amounts borrowed under this facility, in part due to the partial or complete application of net proceeds from equity and debt offerings completed in 2006. We used $430 million of net proceeds from our March 2006 equity offering and $260 million of net proceeds from our September 2006 equity offering to temporarily reduce amounts due under the Multi-Year Revolving Credit Facility. We also used the net proceeds from the Operating Partnership's issuance of Junior Notes A in the third quarter of 2006 to reduce debt outstanding under this facility. We used any remaining net proceeds from these offerings in 2006 for general partnership purposes.

During the first nine months of 2005, our Operating Partnership issued an aggregate of $1 billion in senior notes, the proceeds of which were used to repay $350 million due under Senior Notes A, to temporarily reduce amounts outstanding under our bank credit facilities and for general partnership purposes. Additionally, we repaid the remaining $242.2 million that was due under our 364-Day Acquisition Credit Facility (which was used to finance elements of the GulfTerra merger) using proceeds generated from our February 2005 equity offering.

Net proceeds from the issuance of our limited partner interests were $843 million for the first nine months of 2006 compared to $537.2 million for the first nine months of 2005. With respect to equity offerings (including sales through our distribution reinvestment program), we issued 34,356,436 common units during the first nine months of 2006 versus 19,576,622 common units during the first nine months of 2005. Net proceeds from underwritten equity offerings were $751 million during the first nine months of 2006 reflecting the sale of 31,050,000 common units and $456.7 million during the first nine months of 2005 reflecting the sale of 17,250,000 common units. Our distribution reinvestment program and related employee unit purchase plan generated net proceeds of $84.4 million during the first nine months of 2006, including $50 million reinvested by EPCO in August 2006. In comparison, this program generated proceeds of $59.6 million during the first nine months of 2005, including $30 million reinvested by EPCO in February 2005.

Cash distributions to partners increased from $529 million during the first nine months of 2005 to $616.3 million during the first nine months of 2006. The period-to-period increase in cash distributions is due to an increase in common units outstanding and quarterly cash distribution rates. Cash contributions from minority interests were $23.1 million for the first nine months of 2006 compared to $28.5 million for the same period during 2005. These amounts represent contributions from our joint venture partner in the Independence Hub project.

CONTRACTUAL OBLIGATIONS

Scheduled maturities of long-term debt at September 30, 2006 increased $53 million compared to balances at December 31, 2005. The increase in debt is primarily due to the issuance of Junior Notes A and the temporary repayment of amounts borrowed under our Multi-Year Revolving Credit Facility. For additional information regarding our debt obligations, please read Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

In addition, we renewed our lease of the Wilson natural gas storage facility for an additional 20-year period during the first quarter of 2006. For additional information regarding our commitments under this lease, please read Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Other than the items noted in the previous paragraph, there have been no significant changes with regard to our material contractual obligations (outside of the ordinary course of business) since those reported in our annual report on Form 10-K for the year ended December 31, 2005.

OFF-BALANCE SHEET ARRANGEMENTS

In March 2006, Cameron Highway amended the note purchase agreement governing its senior secured notes to primarily address the effect of reduced deliveries of crude oil to Cameron Highway resulting from production delays caused by the lingering effects of Hurricanes Katrina and Rita. In general, this amendment modified certain financial covenants in light of production forecasts. In addition, the amendment increased the face amount of the letters of credit required to be issued by our Operating Partnership and an affiliate of our joint venture partner from $18.4 million each to $36.8 million each.

In May 2006, Poseidon amended its revolving credit facility to, among other things, reduce commitments from $170 million to $150 million, extend the maturity date from January 2008 to May 2011 and lower the borrowing rate.

Other than the amendments discussed above, there have been no significant changes with regard to our off-balance sheet arrangements since those reported in our annual report on Form 10-K for the year ended December 31, 2005.

RECENT ACCOUNTING DEVELOPMENTS

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

- EITF 04-13, "*Accounting for Purchases and Sale of Inventory With the Same Counterparty*,"
- EITF 06-3, "*How Taxes Collected From Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)*,"
- FIN 48, "*Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS 109, Accounting for Income Taxes*,"
- SFAS 155, "*Accounting for Certain Hybrid Financial Instruments*,"
- SFAS 157, "*Fair Value Measurements*,"
- SFAS 158, "*Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)*," and
- SAB 108, "*Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*."

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

CRITICAL ACCOUNTING POLICIES

In our financial reporting process, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of our financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect.

In general, there have been no significant changes in our critical accounting policies since December 31, 2005. For a detailed discussion of these policies, please read "*Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies*" in our annual report on Form 10-K for the year ended December 31, 2005. The following describes the estimation risk underlying our most significant financial statement items:

Depreciation methods and estimated useful lives of property, plant and equipment

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts on a going forward basis.

At September 30, 2006 and December 31, 2005, the net book value of our property, plant and equipment was $9.4 billion and $8.7 billion, respectively. For additional information regarding our property, plant and equipment, please read Note 6 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Measuring recoverability of long-lived assets and equity method investments

In general, long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Equity method investments are evaluated for impairment whenever events or changes in circumstances indicate that there is a possible loss in value for the investment other than a temporary decline. Measuring the potential impairment of such assets and investments involves the estimation of future cash flows to be derived from the asset being tested. Our estimates of such cash flows are based on a number of assumptions including anticipated margins and volumes; estimated useful life of asset or asset group; and salvage values. A significant change in these underlying assumptions could result in our recording an impairment charge.

Amortization methods and estimated useful lives of qualifying intangible assets

In general, our intangible asset portfolio consists primarily of the estimated values assigned to certain customer relationships and customer contracts. We amortize the customer relationship values using methods that closely resemble the pattern in which the economic benefits of the underlying oil and natural gas resource bases from which the customers produce are estimated to be consumed or otherwise used. We amortize the customer contract intangible assets over the estimated remaining economic life of the underlying contract. A change in the estimates we use to determine amortization rates of our intangible assets (e.g., oil and natural gas production curves, remaining economic life of the contracts, etc.) could result in a material change in the amortization expense we record and the carrying value of our intangible assets.

At September 30, 2006 and December 31, 2005, the carrying value of our intangible asset portfolio was $1 billion and $913.6 million, respectively. For additional information regarding our intangible assets, please read Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Methods we employ to measure the fair value of goodwill

Goodwill represents the excess of the purchase prices we paid for certain businesses over their respective fair values and is primarily comprised of $387.1 million associated with the GulfTerra Merger. We do not amortize goodwill; however, we test our goodwill (at the reporting unit level) for impairment during the second quarter of each fiscal year, and more frequently, if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. Our goodwill testing involves the determination of a reporting unit’s fair value, which is predicated on our assumptions regarding the future economic prospects of the reporting unit. Our estimates of such prospects (i.e., cash flows) are based on a number of assumptions including anticipated margins and volumes of the underlying assets or asset group. A significant change in these underlying assumptions could result in our recording an impairment charge.

At September 30, 2006 and December 31, 2005, the carrying value of our goodwill was $591 million and $494 million, respectively. For additional information regarding our goodwill, please read Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Our revenue recognition policies and use of estimates for revenues and expenses

Our use of certain estimates for revenues and operating costs and other expenses has increased as a result of SEC regulations that require us to submit financial information on accelerated time frames. Such estimates are necessary due to the timing of compiling actual billing information and receiving third-party data needed to record transactions for financial reporting purposes. If the basis of our estimates proves to be substantially incorrect, it could result in material adjustments in results of operations between periods.

Reserves for environmental matters

Each of our business segments is subject to federal, state and local laws and regulations governing environmental quality and pollution control. Such laws and regulations may, in certain instances, require us to remediate current or former operating sites where specified substances have been released or disposed of. We accrue reserves for environmental matters when our assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Our assessments are based on studies, as well as site surveys, to determine the extent of any environmental damage and the necessary requirements to remediate this damage. Future environmental developments, such as increasingly strict environmental laws and additional claims for damages to property, employees and other persons resulting from current or past operations, could result in substantial additional costs beyond our current reserves.

At September 30, 2006 and December 31, 2005, we had a liability for environmental remediation of $23.5 million and $21 million, respectively, which was derived from a range of reasonable estimates based upon studies and site surveys. In accordance with SFAS 5 "*Accounting for Contingencies*" and Financial Accounting Standards Board Interpretation ("FIN") 14, "*Reasonable Estimation of the Amount of a Loss*," we recorded our best estimate of these remediation activities.

Natural gas imbalances

Natural gas imbalances result when customers physically deliver a larger or smaller quantity of natural gas into our pipelines than they take out. In general, we value such imbalances using a twelve-month moving average of natural gas prices, which we believe is reasonable given that the actual settlement dates for such imbalances are generally not known. As a result, significant changes in natural gas prices between reporting periods may impact our estimates.

At September 30, 2006 and December 31, 2005, our imbalance receivables were $108.5 million and $89.4 million, respectively, and are reflected as a component of accounts receivable. At September 30, 2006 and December 31, 2005, our imbalance payables were $39.1 million and $80.5 million, respectively, and are reflected as a component of accrued gas payables.

SUMMARY OF RELATED PARTY TRANSACTIONS

In accordance with SFAS 57, "*Related Party Disclosures*," we have identified our material related party revenues, costs and expenses. 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,	
	2006	2005	2006	2005
Revenues from consolidated operations				
EPCO and affiliates	$ 47,812	$ 1	$ 86,892	$ 287
Unconsolidated affiliates	84,551	118,963	248,980	257,818
Total	$ 132,363	$ 118,964	$ 335,872	$ 258,105
Operating costs and expenses				
EPCO and affiliates	$ 78,570	$ 66,302	$ 244,632	$ 189,124
Unconsolidated affiliates	4,523	11,464	19,113	21,930
Total	$ 83,093	$ 77,766	$ 263,745	$ 211,054
General and administrative expenses				
EPCO and affiliates	$ 10,728	$ 8,640	$ 32,566	$ 28,528

For additional information regarding our related party transactions identified in accordance with GAAP, please read Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

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

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 November 2, 2006, our subsidiary, Duncan Energy Partners, filed its initial registration statement for a proposed 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, please read " – *Other Items – Initial Public Offering of Duncan Energy Partners*" included within this Item 2.

OTHER ITEMS

Initial Public Offering of Duncan Energy Partners

On November 2, 2006, our subsidiary, Duncan Energy Partners, filed its initial registration statement for a proposed initial public offering of its common units. Duncan Energy Partners was formed in September 2006 as a Delaware limited partnership to own, operate and acquire a diversified portfolio of midstream energy assets. At the closing of Duncan Energy Partner's initial public offering, we will contribute 66% of the equity interests in following subsidiaries to Duncan Energy Partners:

§ *Mont Belvieu Caverns, L.P.* ("Mont Belvieu Caverns"), which receives, stores and delivers NGLs and petrochemical products for industrial customers located along the upper Texas Gulf Coast, which has the largest concentration for petrochemical plants and refineries in the United States.

§ *Acadian Gas, LLC* ("Acadian Gas"), which is 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.

§ *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* ("Lou-Tex Propylene"), which transports chemical-grade propylene between Mont Belvieu, Texas and Sorrento, Louisiana; and a

§ *South Texas NGL Pipelines, LLC* ("South Texas NGL"), which will transport NGLs from Corpus Christi, Texas to Mont Belvieu, Texas. South Texas NGL will own the South Texas NGL pipeline system. For additional information regarding our South Texas NGL pipeline system, please read "– *Capital Spending – Significant Recently Announced Growth Capital Projects*" included within this Item 2.

We expect to retain a 34% ownership interest in each of these entities. In addition, we will own the 2% general partner and expect to own approximately 25% of the limited partner interests of Duncan Energy Partners. Our ownership of the limited partner interests of Duncan Energy Partners (following its initial public offering) assumes that the underwriters exercise their overallotment option with respect to the offering. Our Operating Partnership will direct the business operations of Duncan Energy Partners through its ownership and control of Duncan Energy Partners.

From a financial reporting perspective, the formation of Duncan Energy Partners had no effect on our financial statements at September 30, 2006. Beginning with the quarterly period in which the initial public offering of Duncan Energy Partners is completed, we will consolidate the results of Duncan Energy

Partners with minority interest treatment for the common units of Duncan Energy Partners owned by unitholders other than us.

We expect to have significant continuing involvement with all of these assets, including the following types of transactions:

- § We will continue to utilize storage services provided by Mont Belvieu Caverns to support our Mont Belvieu fractionation and other businesses;
- § We will continue to buy from and sell natural gas to Acadian Gas in connection with its normal business activities; and
- § We will be the sole shipper on the NGL pipeline system to be owned by South Texas NGL.

Non-GAAP reconciliations

Gross operating margin. The following table presents a reconciliation 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 a change in accounting principle (dollars in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2006	2005	2006	2005
Total non-GAAP gross operating margin	$ 399,741	$ 311,816	$ 1,022,888	$ 832,905
Adjustments to reconcile total non-GAAP gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(112,412)	(103,028)	(325,180)	(304,041)
Operating lease expense paid by EPCO	(526)	(528)	(1,582)	(1,584)
Gain (loss) on sale of assets in operating costs and expenses	3,204	(611)	3,401	4,742
General and administrative costs	(15,823)	(13,252)	(45,798)	(46,655)
GAAP consolidated operating income	274,184	194,397	653,729	485,367
Other expense	(60,657)	(59,144)	(169,705)	(167,139)
GAAP income before provision for income taxes, minority interest and cumulative effect of change in accounting principle	$ 213,527	$ 135,253	$ 484,024	$ 318,228

EPCO subleases certain equipment located at our Mont Belvieu facility and 100 railcars for $1 per year (the “retained leases”) to us. These subleases are part of an administrative services agreement between EPCO and us that was executed 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 of the retained leases to us.

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. For additional information regarding this cumulative effect adjustment, please read Note 3 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Provision for income taxes – Texas Margin Tax

Prior to the second quarter of 2006, our provision for income taxes related to federal income tax and state franchise and income tax obligations of Seminole and Dixie, which are both corporations and represented our only consolidated subsidiaries that were historically subject to such income taxes. In May

2006, the State of Texas enacted a new business tax (the "Texas Margin Tax") that replaced the existing state franchise tax. In general, legal entities that conduct business in Texas are subject to the Texas Margin Tax. Limited partnerships, limited liability companies, corporations and limited liability partnerships are examples of the types of entities that are subject to the Texas Margin Tax. As a result of the change in tax law, our tax status in the State of Texas will change from non-taxable to taxable. The tax is considered an income tax for purposes of adjustments to deferred tax liability as the tax is determined by applying a tax rate to a base that considers both revenues and expenses. The Texas Margin Tax becomes effective for margin tax reports due on or after January 1, 2008. The Texas Margin Tax due in 2008 will be based on revenues earned during the 2007 fiscal year.

The Texas Margin Tax is assessed at 1% of Texas-sourced taxable margin. The taxable margin is the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. Our deferred tax liability, which is a component of other long-term liabilities on our consolidated balance sheets, reflects the net tax effects of temporary differences related to items such as property, plant and equipment; therefore, the deferred tax liability is noncurrent. We recorded an estimated net deferred tax liability of approximately $6.6 million for the Texas Margin Tax. The offsetting net charge of $6.6 million is shown on our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income as a component of provision for income taxes for the nine months ended September 30, 2006.

The constitutionality of the Texas Margin Tax is being questioned. The Texas Comptroller has requested a formal opinion from the Texas Attorney General on whether the Texas Margin Tax is an income tax that violates the Texas constitution. The Texas constitution requires voter approval of any tax imposed on the net income of natural persons, including a person's share of partnership or unincorporated association income; such approval was not obtained for the Texas Margin Tax. The Comptroller has requested that the Attorney General determine whether the direct imposition of the Texas Margin Tax on partnerships without voter approval violates this constitutional requirement. The Attorney General's decision is not expected until late 2006 or early 2007. If the Texas Margin Tax is ultimately challenged in court, the legislation enacting the Texas Margin Tax gives the Texas Supreme Court jurisdiction over the constitutional challenge and allows the Court to grant injunctive or declaratory relief. The Court would have 120 days from the date the challenge is filed to make a ruling.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION AND RISK FACTORS

This quarterly report contains various forward-looking statements and information based on our beliefs and those of Enterprise Products GP, 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 for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations (as reflected in such forward-looking statements) are reasonable, neither we nor Enterprise Products GP can give any assurance that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions. 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.

When considering forward-looking statements, please read Part II, Item 1A, "*Risk Factors*," included within this quarterly report on Form 10-Q and Part I, Item 1A, "*Risk Factors*," included in our annual report on Form 10-K for 2005.

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

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type 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 certain interest rates or commodity prices. 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 exposures by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt.

Fair value hedges – Interest rate swaps. As summarized in the following table, we had eleven interest rate swap agreements outstanding at September 30, 2006 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 8.89%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 7.43%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.6% to 6.14%	$600 million
Senior Notes K, 4.95% fixed rate, due June 2010	2	Aug. 2005 to June 2010	June 2010	4.95% to 5.73%	$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, 2006 and December 31, 2005, was a liability of $30.4 million and $19.2 million, respectively, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the three months ended September 30, 2006 and 2005 reflects a $1.9 million expense and a $2.3 million benefit from these swap agreements, respectively. For the nine months ended September 30, 2006 and 2005, interest expense reflects a $2.8 million expense and a $9.8 million benefit, respectively, from these swap agreements.

The following table shows the effect of hypothetical price movements on the estimated fair value ("FV") 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 on the first day of each six-month interest calculation period.

Scenario	Resulting Classification	Swap Fair Value at September 30, 2006	Swap Fair Value at October 11, 2006
FV assuming no change in underlying interest rates	*Liability*	$ (30,365)	$ (39,387)
FV assuming 10% increase in underlying interest rates	*Liability*	(59,755)	(69,721)
FV assuming 10% decrease in underlying interest rates	*Liability*	(974)	(9,053)

The change in fair value of our interest rate swaps since December 31, 2005 is primarily due to an increase in interest rates.

Cash flow hedges – Treasury Locks. During the second quarter of 2006, the Operating Partnership entered into a treasury lock transaction having a notional amount of $250 million. In addition, in July 2006, the Operating Partnership entered into an additional treasury lock transaction having a notional amount of $50 million. A treasury lock is a specialized agreement that fixes the price (or yield) on a specific treasury security for an established period of time. A treasury lock purchaser is protected from a rise in the yield of the underlying treasury security during the lock period. The Operating Partnership's purpose of entering into these transactions was to hedge the underlying U.S. treasury rate related to its anticipated issuance of subordinated debt. In July 2006, the Operating Partnership issued $300 million in principal amount of its Junior Notes A. Each of the treasury lock transactions was designated as a cash flow hedge under SFAS 133. In July 2006, the Operating Partnership elected to terminate these treasury lock transactions and recognized a minimal gain.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and 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 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) 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.

The fair value of our commodity financial instrument portfolio at September 30, 2006 and December 31, 2005 was a benefit of $4.8 million and a liability of $0.1 million, respectively. During the three and nine months ended September 30, 2006, we recorded $7.8 million and $2.4 million of income related to our commodity financial instruments, respectively, which is included in operating costs and expenses on our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income. We recorded nominal amounts of earnings from our commodity financial instruments during the three and nine months ended September 30, 2005.

We assess the risk of our commodity financial instrument portfolio using a sensitivity analysis model. This analysis measures potential income or loss resulting from changes in fair value of the portfolio, based upon a hypothetical 10% change in the underlying quoted market prices of the commodity financial instruments. The following table shows the effect of such hypothetical price movements on the estimated fair value of our commodity financial instrument portfolio at the dates indicated (dollars in thousands):

Scenario	Resulting Classification	Commodity Financial Instrument Portfolio FV September 30, 2006	Commodity Financial Instrument Portfolio FV October 11, 2006
FV assuming no change in underlying commodity prices	*Asset*	$ 4,765	$ 11,365
FV assuming 10% increase in underlying commodity prices	*Asset*	2,175	9,607
FV assuming 10% decrease in underlying commodity prices	*Asset*	7,354	13,123

Effect of financial instruments on accumulated other comprehensive income

The following table summarizes the effect of our cash flow hedging financial instruments on accumulated other comprehensive income since December 31, 2005.

	Commodity Financial Instruments	Interest Rate Financial Instruments	Accumulated Other Comprehensive Income Balance
Balance, December 31, 2005		$ 19,072	$ 19,072
Change in fair value of commodity financial instruments	$ 4,880		4,880
Reclassification of gain on settlement of interest rate financial instruments		(3,158)	(3,158)
Balance, September 30, 2006	$ 4,880	$ 15,914	$ 20,794

During the remainder of 2006, we will reclassify $1.1 million from accumulated other comprehensive income to earnings as a reduction in consolidated interest expense.

Item 4. *Controls and Procedures*.

Our management, with the participation of the chief executive officer ("CEO") and chief financial officer ("CFO") of our general partner, has evaluated the effectiveness of our disclosure controls and procedures, including internal controls over financial reporting, as of the end of the period covered by this report. Based on their evaluation, the CEO and CFO of our general partner have concluded that our disclosure controls and procedures are effective to ensure that material information relating to our partnership is made known to management on a timely basis. Our CEO and CFO noted no material weaknesses in the design or operation of our internal controls over financial reporting that are likely to adversely affect our ability to record, process, summarize and report financial information. Also, they detected no fraud involving management or employees who have a significant role in our internal controls over financial reporting.

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) that have not been evaluated by management and no other factors that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

Collectively, these disclosure controls and procedures are designed to provide us with reasonable assurance that the information required to be disclosed in our periodic reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. 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 15, "*Commitments and Contingencies – Litigation*," which is incorporated herein by reference.

Item 1A. *Risk Factors*.

Apart from that discussed below, there have been no significant changes in our risk factors since December 31, 2005. For a detailed discussion of our risk factors, please read, Item 1A "*Risk Factors*," in our annual report on Form 10-K for the year ended December 31, 2005.

If we were to become subject to entity level taxation for federal or state tax purposes, then our cash available for distribution to common unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service on this matter.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and we likely would pay state taxes as well. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses or deductions would flow though to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distributions to our common unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the after-tax return to our common unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change, causing us to be treated as a corporation for United States federal income tax purposes or otherwise subjecting us to entity level taxation. For example, because of widespread state budget deficits, certain states, including Texas, have taken steps to subject partnerships to entity level taxation through the imposition of state income, franchise or other forms of taxation. To the extent any state imposes an income tax or other tax upon us as an entity, the cash available for distribution to our common unitholders would be reduced.

We may not consummate the proposed initial public offering of common units for Duncan Energy Partners on terms that we expect or at all, which would result in less cash available for us to fund other growth capital projects.

Although Duncan Energy Partners has filed a registration statement for an initial public offering of its common units, we may not be able to consummate the offering on terms that we expect or at all. If we do not consummate that offering or we are required to change the current proposed terms of our contributions and related-party agreements with Duncan Energy Partners, we may have less cash available to fund our other growth capital projects. Our cost of capital for funding these projects may be higher than cash made available through our contribution of assets and the initial public offering of common units by Duncan Energy Partners.

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, 2006. As of September 30, 2006, 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	Purchase and Sale Agreement between Coral Energy, LLC and Enterprise Products Operating L.P. dated September 22, 2000 (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 26, 2000).
2.2	Purchase and Sale Agreement dated January 16, 2002 by and between Diamond-Koch, L.P. and Diamond-Koch III, L.P. and Enterprise Products Texas Operating L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 8, 2002.)
2.3	Purchase and Sale Agreement dated January 31, 2002 by and between D-K Diamond-Koch, L.L.C., Diamond-Koch, L.P. and Diamond-Koch III, L.P. as Sellers and Enterprise Products Operating L.P. as Buyer (incorporated by reference to Exhibit 10.2 to Form 8-K filed February 8, 2002).
2.4	Purchase Agreement by and between E-Birchtree, LLC and Enterprise Products Operating L.P.

	dated July 31, 2002 (incorporated by reference to Exhibit 2.2 to Form 8-K filed August 12, 2002).
2.5	Purchase Agreement by and between E-Birchtree, LLC and E-Cypress, LLC dated July 31, 2002 (incorporated by reference to Exhibit 2.1 to Form 8-K filed August 12, 2002).
2.6	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).
2.7	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).
2.8	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).
2.9	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).
2.10	Second Amended and Restated Limited Liability Company Agreement of GulfTerra Energy Company, L.L.C., adopted by GulfTerra GP Holding Company, a Delaware corporation, and Enterprise Products GTM, LLC, a Delaware limited liability company, as of December 15, 2003, (incorporated by reference to Exhibit 2.3 to Form 8-K filed December 15, 2003).
2.11	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of GulfTerra Energy Company, L.L.C. adopted by Enterprise Products GTM, LLC as of September 30, 2004 (incorporated by reference to Exhibit 2.11 to Registration Statement on Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
2.12	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	Third Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated as of August 29, 2005 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 1, 2005).
3.3	Amended and Restated Agreement of Limited Partnership of Enterprise Products Operating L.P. dated as of July 31, 1998 (restated to include all agreements through December 10, 2003) (incorporated by reference to Exhibit 3.1 to Form 8-K filed July 1, 2005).
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).
4.1	$2.25 Billion 364-Day 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, Citicorp North America, Inc. and Lehman Commercial Paper Inc., as Co-Syndication Agents, JPMorgan Chase Bank, UBS Loan Finance LLC and Morgan Stanley Senior Funding, Inc., as Co-Documentation Agents, Wachovia Capital Markets, LLC, Citigroup Global Markets Inc. and Lehman Brothers Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 4.3 to Form 8-K filed on August 30, 2004).
4.2	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).
4.3	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).
4.4	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).
4.5	Form of Junior Note, including Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed July 19, 2006).
4.6	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).
18.1	Letter regarding Change in Accounting Principles dated May 4, 2004 (incorporated by reference to Exhibit 18.1 to Form 10-Q filed May 10, 2004).
31.1#	Sarbanes-Oxley Section 302 certification of Robert G. Phillips for Enterprise Products Partners L.P. for the September 30, 2006 quarterly report on Form 10-Q.
31.2#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the September 30, 2006 quarterly report on Form 10-Q.
32.1#	Section 1350 certification of Robert G. Phillips for the September 30, 2006 quarterly report on Form 10-Q.
32.2#	Section 1350 certification of Michael A. Creel for the September 30, 2006 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 1-14323.

\# Filed with this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this quarterly report on Form 10-Q to be signed on its behalf by the undersigned thereunto duly authorized, in the City of Houston, State of Texas on November 8, 2006.

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

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF MICHAEL A. CREEL, CHIEF FINANCIAL OFFICER OF ENTERPRISE PRODUCTS GP, LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this quarterly report of Enterprise Products Partners L.P. (the “Registrant”) on Form 10-Q for the quarterly period ended September 30, 2006 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Michael A. Creel, Chief Financial Officer of Enterprise Products GP, LLC, the general partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

___/s/ Michael A. Creel________________________________
Name: Michael A. Creel
Title: Chief Financial Officer of Enterprise Products GP, LLC
on behalf of Enterprise Products Partners L.P.

Date: November 8, 2006

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF ROBERT G. PHILLIPS, CHIEF EXECUTIVE OFFICER OF ENTERPRISE PRODUCTS GP, LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this quarterly report of Enterprise Products Partners L.P. (the “Registrant”) on Form 10-Q for the quarterly period ended September 30, 2006 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert G. Phillips, Chief Executive Officer of Enterprise Products GP, LLC, the general partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

___/s/ Robert G. Phillips______________________________________
Name: Robert G. Phillips
Title: Chief Executive Officer of Enterprise Products GP, LLC
on behalf of Enterprise Products Partners L.P.

Date: November 8, 2006

EXHIBIT 31.2

CERTIFICATIONS

I, Michael A. Creel, certify that:

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

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

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

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

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

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

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

Date: November 8, 2006

___/s/ Michael A. Creel___________________________
Name: Michael A. Creel
Title: Principal Financial Officer of our General Partner, Enterprise Products GP, LLC

EXHIBIT 31.1

CERTIFICATIONS

I, Robert G. Phillips, certify that:

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

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

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

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

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

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

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

Date: November 8, 2006

___/s/ Robert G. Phillips___________________________
Name: Robert G. Phillips
Title: Principal Executive Officer of our General Partner, Enterprise Products GP, LLC