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

FORM 10-Q

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

For the quarterly period ended June 30, 2005 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.)

2727 North Loop West, Houston, Texas	**77008-1044**
(Address of Principal Executive Offices)	(Zip Code)

Registrant's Telephone Number, including area code: **(713) 880-6500**

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 an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

YES x NO o

There were 384,695,836 common units of *Enterprise Products Partners L.P.* outstanding at July 31, 2005. Enterprise Products Partners L.P.'s common units trade on the New York Stock Exchange under the symbol "EPD."

ENTERPRISE PRODUCTS PARTNERS L.P.
TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION.
ITEM 1. FINANCIAL STATEMENTS.

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

ASSETS	June 30, 2005	December 31, 2004
Current assets		
Cash and cash equivalents	$ 33,045	$ 24,556
Restricted cash	13,027	26,157
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $24,083 at June 30, 2005 and $24,310 at December 31, 2004	1,022,179	1,058,375
Accounts receivable - related parties	201	25,161
Inventories	365,803	189,019
Assets held for sale		36,562
Prepaid and other current assets	109,583	80,893
Total current assets	1,543,838	1,440,723
Property, plant and equipment, net	8,182,589	7,831,467
Investments in and advances to unconsolidated affiliates	479,146	519,164
Intangible assets, net of accumulated amortization of $119,682 at June 30, 2005 and $74,183 at December 31, 2004	956,956	980,601
Goodwill	483,377	459,198
Deferred tax asset	7,737	6,467
Long-term receivables	14,815	14,931
Other assets	61,511	62,910
Total assets	$ 11,729,969	$ 11,315,461
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities		
Current maturities of debt	$ 15,000	$ 15,000
Accounts payable - trade	113,541	203,142
Accounts payable - related parties	15,538	41,293
Accrued gas payables	971,675	1,021,294
Accrued expenses	31,295	130,051
Accrued interest	69,761	70,335
Other current liabilities	114,094	104,764
Total current liabilities	1,330,904	1,585,879
Long-term debt	4,568,447	4,266,236
Other long-term liabilities	58,708	63,521
Minority interest	85,735	71,040
Commitments and contingencies		
Partners' equity		
Common units (384,200,634 units outstanding at June 30, 2005 and 364,297,340 units at December 31, 2004)	5,548,784	5,204,940
Restricted common units (495,202 units outstanding at June 30, 2005 and 488,525 units at December 31, 2004)	12,237	12,327
Treasury units, at cost (427,200 units outstanding at December 31, 2004)		(8,660)
General partner	113,490	106,475
Accumulated other comprehensive income	21,119	24,554
Deferred compensation	(9,455)	(10,851)
Total partners' equity	5,686,175	5,328,785
Total liabilities and partners' equity	$ 11,729,969	$ 11,315,461

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 June 30,		For the Six Months Ended June 30,	
	2005	2004	2005	2004
REVENUES				
Third parties	$ 2,590,820	$ 1,510,549	$ 5,088,149	$ 3,060,136
Related parties	80,948	202,797	139,141	358,100
Total	2,671,768	1,713,346	5,227,290	3,418,236
COST AND EXPENSES				
Operating costs and expenses				
Third parties	2,461,960	1,426,885	4,780,489	2,832,868
Related parties	68,173	226,432	133,288	441,957
Total operating costs and expenses	2,530,133	1,653,317	4,913,777	3,274,825
General and administrative costs				
Third parties	8,073	1,342	13,515	3,914
Related parties	10,637	5,745	19,888	12,639
Total general and administrative costs	18,710	7,087	33,403	16,553
Total costs and expenses	2,548,843	1,660,404	4,947,180	3,291,378
EQUITY IN INCOME OF UNCONSOLIDATED AFFILIATES	2,581	13,068	10,860	27,935
OPERATING INCOME	125,506	66,010	290,970	154,793
OTHER INCOME (EXPENSE)				
Interest expense	(56,746)	(31,867)	(110,159)	(64,485)
Other, net	1,245	168	2,164	329
Other expense	(55,501)	(31,699)	(107,995)	(64,156)
INCOME BEFORE PROVISION FOR INCOME TAXES, MINORITY INTEREST AND CHANGES IN ACCOUNTING PRINCIPLES	70,005	34,311	182,975	90,637
Provision for income taxes	1,034	(419)	(735)	(2,044)
INCOME BEFORE MINORITY INTEREST AND CHANGES IN ACCOUNTING PRINCIPLES	71,039	33,892	182,240	88,593
Minority interest	(380)	(744)	(2,325)	(3,698)
INCOME BEFORE CHANGES IN ACCOUNTING PRINCIPLES	70,659	33,148	179,915	84,895
Cumulative effect of changes in accounting principles (see Note 1)				10,781
NET INCOME	70,659	33,148	179,915	95,676
Cash flow financing hedges		87,558		104,531
Amortization of cash flow financing hedges	(1,006)	(104)	(2,001)	(206)
Change in fair value of commodity hedges			(1,434)	
COMPREHENSIVE INCOME	$ 69,653	$ 120,602	$ 176,480	$ 200,001
ALLOCATION OF NET INCOME:				
Limited partners' interest in net income	$ 54,040	$ 26,306	$ 147,763	$ 81,432
General Partner interest in net income	$ 16,619	$ 6,842	$ 32,152	$ 14,244
EARNINGS PER UNIT: (see Note 14)				
Basic income per unit before change in accounting principles	$ 0.14	$ 0.11	$ 0.39	$ 0.32
Basic net income per unit	$ 0.14	$ 0.11	$ 0.39	$ 0.37
Diluted income per unit before change in accounting principles	$ 0.14	$ 0.11	$ 0.39	$ 0.32
Diluted net income per unit	$ 0.14	$ 0.11	$ 0.39	$ 0.37

See Notes to Unaudited Condensed Consolidated Financial Statements

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

	For the Six Months Ended June 30,	
	2005	**2004**
OPERATING ACTIVITIES		
Net income	$ 179,915	$ 95,676
Adjustments to reconcile net income to cash flows provided by operating activities:		
Depreciation and amortization in operating costs and expenses	201,013	62,235
Depreciation in general and administrative costs	3,490	155
Amortization in interest expense	(370)	1,843
Equity in income of unconsolidated affiliates	(10,860)	(27,935)
Distributions received from unconsolidated affiliates	38,908	35,857
Cumulative effect of changes in accounting principles		(10,781)
Operating lease expense paid by EPCO, Inc.	1,056	4,547
Minority interest	2,325	3,698
Loss (gain) on sale of assets	(5,353)	115
Deferred income tax expense	3,875	2,912
Changes in fair market value of financial instruments	111	3
Net effect of changes in operating accounts (see Note 11)	(296,273)	(51,181)
Cash provided by operating activities	117,837	117,144
INVESTING ACTIVITIES		
Capital expenditures	(435,769)	(28,264)
Contributions in aid of construction costs	27,032	349
Proceeds from sale of assets	42,267	59
Decrease (increase) in restricted cash	13,130	(9,286)
Cash used for business combinations, net of cash received	(181,079)	(45,085)
Acquisition of intangible asset	(1,750)	
Investments in unconsolidated affiliates	(80,650)	(468)
Advances to unconsolidated affiliates	(1,130)	(1,289)
Return of investment from unconsolidated affiliate	47,500	
Cash used in investing activities	(570,449)	(83,984)
FINANCING ACTIVITIES		
Borrowings under debt agreements	2,612,345	483,000
Repayments of debt	(2,341,007)	(845,000)
Debt issuance costs	(8,287)	(954)
Distributions paid to partners	(346,571)	(180,951)
Distributions paid to minority interests	(4,154)	(2,053)
Contributions from minority interests	23,564	
Contribution from general partner related to issuance of restricted units	7	35
Proceeds from issuance of common units	525,204	411,584
Treasury units reissued		5,607
Settlement of cash flow financing hedges		104,531
Cash provided by (used in) financing activities	461,101	(24,201)
NET CHANGE IN CASH AND CASH EQUIVALENTS	8,489	8,959
CASH AND CASH EQUIVALENTS, JANUARY 1	24,556	30,466
CASH AND CASH EQUIVALENTS, JUNE 30	$ 33,045	$ 39,425

See Notes to Unaudited Condensed Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY
(See Note 9 for Unit History and Detail of Changes in Limited Partners' Equity)
(Dollars in thousands)

	Limited Partners	General Partner	Treasury Units	Deferred Compensation	Accumulated Other Comprehensive Income	Total
Balance, December 31, 2004	$ 5,217,267	$ 106,475	$ (8,660)	$ (10,851)	$ 24,554	$ 5,328,785
Net income	147,763	32,152				179,915
Operating leases paid by EPCO, Inc.	1,035	21				1,056
Cash distributions to partners	(311,086)	(35,485)				(346,571)
Net proceeds from sales of common units	496,055	10,123				506,178
Proceeds from exercise of unit options	18,645	381				19,026
Issuance of restricted units	257	5		(260)		2
Amortization of deferred compensation				1,656		1,656
Cancellation of treasury units	(8,915)	(182)	8,660			(437)
Change in fair value of commodity hedges					(1,434)	(1,434)
Interest rate hedging financial instruments recorded as cash flow hedges:						
Amortization of gain as component of interest expense					(2,001)	(2,001)
Balance, June 30, 2005	$ 5,561,021	$ 113,490	$ -	$ (9,455)	$ 21,119	$ 5,686,175

See Notes to Unaudited Condensed Consolidated Financial Statements

1. GENERAL

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

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 GP"). We and Enterprise GP are affiliates of EPCO, Inc. ("EPCO"). As used in this document, "GulfTerra Merger" refers to the merger of GulfTerra Energy Partners, L.P. with a wholly owned subsidiary of Enterprise on September 30, 2004 and the various transactions related thereto. References to "GulfTerra" mean Enterprise GTM Holdings L.P., the successor to GulfTerra Energy Partners, L.P. References to "GulfTerra GP" mean Enterprise GTMGP, L.L.C., which was formerly known as GulfTerra Energy Company, L.L.C., the general partner of GulfTerra Energy Partners L.P. Enterprise GTMGP, L.L.C. is the general partner of Enterprise GTM Holdings L.P.

In the opinion of Enterprise, the accompanying unaudited condensed consolidated financial statements include all adjustments consisting of normal recurring accruals necessary for fair presentation. Although we believe the disclosures in these financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with 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"). These unaudited financial statements should be read in conjunction with our annual report on Form 10-K for the year ended December 31, 2004 (Commission File No. 1-14323).

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 15 for condensed consolidated financial information of our Operating Partnership.

The results of operations for the three and six months ended June 30, 2005 are not necessarily indicative of results expected for the full year.

Except per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

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

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

Certain reclassifications have been made to the prior year's financial statements to conform to the current year presentation. In accordance with Statement of Financial Accounting Standards ("SFAS") No. 3, "*Reporting Accounting Changes in Interim Financial Statements*," we have reclassified amounts related to our adoption of Emerging Issues Task Force ("EITF") 03-16, "*Accounting for Investments in Limited Liability Companies*," on July 1, 2004. Our adoption of EITF 03-16 on that date required us to change our method of accounting for our 13.1% investment in Venice Energy Services Company, LLC ("VESCO") to the equity method from the cost method. Since this change in accounting principle was made during the third quarter of 2004, our statement of consolidated operations and statement of consolidated cash flows for the first and second quarters of 2004 has been recast for comparability purposes.

The cumulative effect of changes in accounting principles represents the combined impact of changing (i) the method our Belvieu Environmental Fuels, L.P. ("BEF") subsidiary uses to account for its planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred method and (ii) the method we used to account for our investment in VESCO.

In our Unaudited Condensed Consolidated Statement of Cash Flows for the six months ended June 30, 2005, we changed the classification of changes in restricted cash to present such changes as an investing activity. We previously presented such changes as an operating activity. In the accompanying Unaudited Condensed Consolidated Statement of Cash Flows for the six months ended June 30, 2004, we reclassified the change in restricted cash to be consistent with our 2005 presentation which resulted in a $9.3 million increase to cash flows used in investing activities and a corresponding increase to cash provided by operating activities from the amounts previously presented.

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.

Unit option plan accounting

Our unit option plan accounting is based on the intrinsic-value method described in Accounting Principles Board Opinion ("APB") No. 25, "*Accounting for Stock Issued to Employees.*" Under this method, no compensation expense is recorded related to options granted when the exercise price is equal to or greater than the market price of the underlying equity on the date of grant. In accordance with SFAS No. 148, "*Accounting for Stock-Based Compensation – Transition and Disclosure*," we disclose the pro forma effect on our earnings as if the fair-value method of SFAS No. 123, "*Accounting for Stock-Based Compensation*" had been used instead of the intrinsic-value method of APB No. 25. The effects of applying SFAS No. 123 in the following pro forma disclosure may not be indicative of future amounts as additional awards in future years are anticipated. The following table shows the pro forma effects for the periods indicated.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2005	2004	2005	2004
Reported net income	$ 70,659	$ 33,148	$ 179,915	$ 95,676
Additional unit option-based compensation expense estimated using fair value-based method	(138)	(233)	(276)	(466)
Pro forma net income	70,521	32,915	179,639	95,210
Less incentive earnings allocations to Enterprise GP	(15,516)	(6,305)	(29,136)	(12,582)
Pro forma net income after incentive earnings allocation	55,005	26,610	150,503	82,628
Multiplied by Enterprise GP ownership interest	2.0%	2.0%	2.0%	2.0%
Standard earnings allocation to Enterprise GP	$ 1,100	$ 532	$ 3,010	$ 1,653
Incentive earnings allocation to Enterprise GP	$ 15,516	$ 6,305	$ 29,136	$ 12,582
Standard earnings allocation to Enterprise GP	1,100	532	3,010	1,653
Enterprise GP interest in pro forma net income	$ 16,616	$ 6,837	$ 32,146	$ 14,235
Pro forma net income	$ 70,521	$ 32,915	$ 179,639	$ 95,210
Less Enterprise GP interest in pro forma net income	(16,616)	(6,837)	(32,146)	(14,235)
Pro forma net income available to limited partners	$ 53,905	$ 26,078	$ 147,493	$ 80,975
Basic earnings per unit, net of Enterprise GP interest:				
Historical units outstanding	384,229	230,189	378,871	224,326
As reported	$ 0.14	$ 0.11	$ 0.39	$ 0.37
Pro forma	$ 0.14	$ 0.11	$ 0.39	$ 0.36
Diluted earnings per unit, net of Enterprise GP interest:				
Historical units outstanding	384,809	230,625	379,537	224,822
As reported	$ 0.14	$ 0.11	$ 0.39	$ 0.37
Pro forma	$ 0.14	$ 0.11	$ 0.39	$ 0.36

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model and various assumptions. For those options granted during 2005, we used the following assumptions to develop our Black-Scholes model estimates: (i) expected life of options of 7 years; (ii) risk-free interest rate of 3.9%, (iii) expected dividend yield of 9.5% and (iv) expected unit price volatility of 27.8%.

Dixie Pipeline Company ("Dixie") employee benefit plans

During the first quarter of 2005, we acquired additional ownership interests in Dixie that resulted in Dixie becoming a consolidated subsidiary of ours (see Note 3). Dixie employs the personnel who operate the Dixie pipeline. Dixie's employees are eligible to participate in Dixie's company-sponsored defined contribution plan. Additionally, certain Dixie employees are eligible to participate in Dixie's pension and postretirement benefit plans. At June 30, 2005, the preliminary estimated fair value of Dixie's employee benefit plan obligations was approximately $6.6 million, and is included in other long-term liabilities on our Unaudited Condensed Consolidated Balance Sheet. This valuation estimate could change due to this recent transaction and the refinement of our estimate.

Defined contribution plan. Dixie sponsors a defined contribution plan in which its employees are eligible to participate. Dixie contributes 3% of eligible compensation to the plan (the "Automatic Contribution") for employees hired on or after July 1, 2004. Plan participants may contribute from 1% to 16% of their eligible compensation to the plan, and Dixie matches each participant's contributions up to a maximum of 6% of eligible compensation, less the Automatic Contribution amount. For the three and six months ended June 30, 2005, Dixie contributed approximately $0.1 million to its defined contribution plan.

Pension and postretirement benefit plans. Certain Dixie employees hired prior to July 1, 2004, are eligible to participate in Dixie's pension and postretirement benefit plans. Dixie's pension plan is a noncontributory defined benefit plan that provides for the payment of benefits to retirees based on age at retirement, years of credited service, and average compensation. Dixie's postretirement benefit plan provides medical and life insurance to retired employees. The medical plan is contributory and the life insurance plan is noncontributory. Any Dixie employee retiring on or after July 1, 2004 will receive postretirement benefits only until such retiree becomes eligible for Medicare benefits.

The following table shows the components of Dixie's net pension and postretirement benefit costs for the periods indicated:

	Pension plan		Postretirement plan	
	Three Months Ended	Six Months Ended	Three Months Ended	Six Months Ended
	June 30, 2005		June 30, 2005	
Service cost	$ 113	$ 150	$ 22	$ 29
Interest cost	128	171	60	80
Expected return on plan assets	(89)	(119)		
Amortization of transition obligation			37	49
Amortization of prior service cost	(3)	(4)	(67)	(89)
Amortization of net loss	21	28	3	4
Net periodic benefit cost	$ 170	$ 226	$ 55	$ 73

During the remainder of 2005, Dixie expects to contribute approximately $0.7 million to its pension plan and approximately $0.2 million to its postretirement benefit plan.

2. RECENTLY ISSUED ACCOUNTING STANDARDS

SFAS No. 123(R), "Share-Based Payment." This accounting guidance, which is applicable for public companies the first fiscal year beginning on or after June 15, 2005, replaces SFAS No. 123, "*Accounting for Stock-Based Compensation*" and supersedes APB No. 25, "*Accounting for Stock Issued to Employees*." This Statement eliminates the ability to account for share-based compensation transactions using APB No. 25, and generally requires instead that such transactions be accounted for using a fair-value-based method. We are continuing to evaluate the provisions of SFAS No. 123(R) and will adopt the standard on January 1, 2006. Upon the required effective date, we will apply this statement using a modified prospective application as described in the standard.

On March 29, 2005, the SEC issued Staff Accounting Bulletin ("SAB") 107 to provide public companies additional guidance in applying the provisions of SFAS No. 123(R). Among other things, SAB 107 describes the SEC staff's expectations in determining the assumptions that underlie the fair value estimates and discusses the interaction of SFAS No. 123(R) with certain existing SEC guidance. The guidance is also beneficial to users of financial statements in analyzing the information provided under SFAS No. 123(R). We will apply the provisions of SAB 107 upon the adoption of SFAS No. 123(R).

FASB Interpretation ("FIN") 46(R)-5, "Implicit Variable Interests Under FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities." On March 3, 2005, the FASB issued this guidance to address whether a reporting enterprise has an implicit variable interest in a variable interest entity or potential variable interest entity when specific conditions exist. FIN 46(R)-5 covers issues that commonly arise in leasing arrangements among related parties, as well as other types of arrangements involving both related and unrelated parties. Implicit variable interests are implied financial interests in an entity's net assets exclusive of variable interests. An implicit variable interest acts the same as in an explicit variable interest except it involves the absorbing and (or) receiving of variability indirectly from the entity (rather than directly). The identification of an implicit variable interest is a matter of judgment that depends on the relevant facts and circumstances. This guidance was effective for our fiscal quarter ended June 30, 2005, and our adoption of this guidance did not have any impact on our financial position, results of operations or cash flows.

FIN 47, "Accounting for Conditional Asset Retirement Obligations." Under SFAS No. 143, "*Accounting for Asset Retirement Obligations*," a company must record a liability for its legal obligations resulting from the eventual retirement of its tangible long-lived assets, whether that obligation results from the acquisition, construction, or development of the asset. However, many companies have not recorded a liability, concluding that either (1) the conditional nature of the obligation does not create a liability until the retirement activity occurs or (2) the timing and/or the method of settling the obligation is unknown. FIN 47 concludes otherwise. If required legally, an obligation associated with the asset's retirement is inevitable even though uncertainties exist about the timing and/or method of settling the obligation. According to FIN 47, these uncertainties affect the fair value of the liability, rather than prevent the need to record one at all. Additionally, the ability of a company to postpone indefinitely the settlement of the obligation, or to sell the asset prior to its retirement, does not relieve a company of its present duty to settle the obligation. We are currently studying the effects of FIN 47 on our accounting policy for asset retirement obligations. We will adopt FIN 47 in December 2005.

SFAS No. 154, "Accounting Changes and Error Corrections." This accounting guidance, which replaces APB No. 20, "*Accounting Changes*" and SFAS No. 3, "*Reporting Accounting Changes in Interim Financial Statements - an amendment of APB No. 28*," provides guidance on the accounting for and reporting of accounting changes and error corrections. It establishes, unless impracticable, retrospective application as the required method for reporting a change in accounting principle in the absence of explicit transition requirements specific to the newly adopted accounting principle. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. We will adopt the provisions of SFAS No. 154 as applicable beginning in fiscal 2006.

3. BUSINESS COMBINATIONS

As summarized below, we recorded purchase accounting adjustments related to the GulfTerra Merger and completed several smaller acquisitions during the first six months of 2005. All such purchase price allocations are preliminary.

GulfTerra Merger purchase price and purchase price allocation adjustments. During the first six months of 2005, we made purchase price adjustments related to the GulfTerra Merger, and we revised our preliminary purchase price allocation related to the GulfTerra Merger. The purchase price adjustments of $7 million, which increased our overall consideration paid to complete the GulfTerra Merger, were primarily attributable to merger-related financial advisory services and involuntary severance costs, both of which were attributable to the GulfTerra Merger.

The GulfTerra Merger was completed on September 30, 2004, when GulfTerra merged with a wholly owned subsidiary of Enterprise. The aggregate value of total consideration Enterprise paid or issued to complete the GulfTerra Merger was approximately $4 billion. Our purchase price allocations related to the GulfTerra Merger remain preliminary and could change due to the refinement of our estimates, including the estimated recovery of expenditures resulting from damages to certain offshore operations due to the effects of Hurricane Ivan, a Category 3 hurricane which struck the U.S. Gulf Coast in September 2004 prior to the GulfTerra Merger.

Indian Springs acquisition in January 2005. In January 2005, we paid $74.5 million for membership interests in Teco Gas Gathering, LLC and Teco Gas Processing, LLC. As a result of this acquisition, we indirectly own an 80% equity interest in the 89-mile Indian Springs Gathering System and a 75% equity interest in the Indian Springs natural gas processing facility, both of which are located in East Texas. The Indian Springs processing facility has capacity to process up to 120 MMcf/d of natural gas and there is an idle 20 MMcf/d production train available for restart to support increases in natural gas volumes. The natural gas processed at the Indian Springs processing facility is sourced from the Indian Springs Gathering System, as well as our nearby Big Thicket Gathering System.

Acquisition of additional interests in Dixie in January and February 2005. We purchased an approximate 20% interest in Dixie in January 2005 for $31 million and an approximate 26% interest in Dixie in February 2005 for $40 million. As a result of these acquisitions, our ownership interest in Dixie increased to approximately 66% and Dixie became a consolidated subsidiary of ours in February 2005. Dixie owns and operates a 1,301-mile natural gas liquid ("NGL") pipeline, which transports propane from supply areas in Texas, Louisiana and Mississippi to markets throughout the southeastern United States.

Acquisition of additional interests in Mid-America and Seminole Pipelines in June 2005. We exercised our option to acquire a 2% indirect ownership interest in the Mid-America Pipeline System and a 1.6% indirect interest in the Seminole pipeline for a total purchase price of $25 million. As a result of this transaction, we own 100% of the Mid-America Pipeline System and 90% of the Seminole pipeline. The Mid-America Pipeline System is a 7,226-mile NGL pipeline system located in the central and western regions of the United States. The Seminole pipeline is a 1,281-mile NGL pipeline that interconnects with the Mid-America Pipeline System at the Hobbs Hub on the Texas-New Mexico border and extends to Mont Belvieu, Texas.

Acquisition of additional interest in Belle Rose NGL Pipeline LLC ("Belle Rose") in June 2005. We purchased an approximate 41.7% interest in Belle Rose in June 2005 for approximately $4.5 million in cash. As a result of this acquisition, our ownership interest in Belle Rose increased to 83.4% and Belle Rose became a consolidated subsidiary of ours in June 2005. The 48-mile Belle Rose NGL pipeline transports mixed NGLs to NGL fractionation facilities located in Louisiana.

Allocation of preliminary purchase price for 2005 business combinations and other purchase accounting adjustments

The acquisitions and post-closing purchase price adjustments described previously were accounted for under the purchase method of accounting and, accordingly, the cost of each has been allocated to the assets acquired and liabilities assumed based on their estimated preliminary fair values as follows:

	Indian Springs	Dixie	Mid-America & Seminole	GulfTerra	Belle Rose	Other	Total
Purchase price allocation:							
Assets acquired in business combination:							
Current assets	$ 354	$ (476)		$ 6,005	$ 562	$ (3,095)	$ 3,350
Property, plant and equipment, net	41,572	91,402	$ 9,390		17,878	3,090	163,332
Investments in and advances to unconsolidated affiliates (1)		(36,253)			(10,017)		(46,270)
Intangible assets	19,095					1,009	20,104
Other assets		32,023		(3,694)			28,329
Total assets acquired	61,021	86,696	9,390	2,311	8,423	1,004	168,845
Liabilities assumed in business combination:							
Current liabilities		(2,758)		338	(52)		(2,472)
Long-term debt		(9,982)					(9,982)
Other long-term liabilities		(6,535)					(6,535)
Minority interest		(4,563)	15,610		(4,007)		7,040
Total liabilities assumed		(23,838)	15,610	338	(4,059)		(11,949)
Total assets acquired less liabilities assumed	61,021	62,858	25,000	2,649	4,364	1,004	156,896
Total consideration given	74,854	68,608	25,000	7,028	4,364	1,225	181,079
Goodwill	$ 13,833	$ 5,750	$ -	$ 4,379	$ -	$ 221	$ 24,183

(1) Represents carrying value of our investment prior to consolidation.

The purchase price allocations shown in the preceding table are preliminary. Enterprise has engaged an independent third-party business valuation expert to assess the fair values of the tangible and intangible assets of Dixie, Belle Rose, and those acquired in the Indian Springs acquisition. This information will assist management in the development of definitive allocations of the overall purchase prices for these transactions. The allocation of the purchase price for additional interests in Dixie reflects preliminary estimates of Dixie’s pension and postretirement obligations. Management independently developed the fair value estimates for our acquisition of additional interests in the Mid-America and Seminole pipelines using recognized business valuation techniques.

4. INVENTORIES

Our inventories consisted of the following at the dates indicated:

	June 30, 2005	December 31, 2004
Working inventory	$ 254,012	$ 171,485
Forward-sales inventory	111,791	17,534
Inventory	$ 365,803	$ 189,019

Our regular trade (or “working”) inventory is comprised of inventories of natural gas, NGLs, and petrochemical products that are available for sale or used in the provision of services. The forward sales inventory is comprised of segregated NGL 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 inventories. For the three months ended June 30, 2005 and 2004, such consolidated cost of sales amounts were $2.2 billion and $1.5 billion, respectively. We recorded $4.3 billion and $3 billion of such consolidated cost of sales amounts for the six months ended June 30, 2005 and 2004, respectively.

Due to fluctuating 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 adjustments are charged to cost of sales within operating costs and expenses in the period they are recognized. For the three months ended June 30, 2005 and 2004, we recognized $7.4 million and $1.9 million, respectively, of such adjustments. We recorded $17 million and $6 million of such adjustments for the six months ended June 30, 2005 and 2004, respectively.

5. PROPERTY, PLANT AND EQUIPMENT

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

	Estimated Useful Life in Years	June 30, 2005	December 31, 2004
Plants and pipelines (1)	5-35 (5)	$ 7,971,609	$ 7,691,197
Underground and other storage facilities (2)	5-35 (6)	537,839	531,394
Platforms and facilities (3)	23-31	162,694	162,645
Transportation equipment (4)	3-10	8,434	7,240
Land		30,534	29,142
Construction in progress		455,032	230,375
Total		9,166,142	8,651,993
Less accumulated depreciation		983,553	820,526
Property, plant and equipment, net		$ 8,182,589	$ 7,831,467

(1) Plants and pipelines includes 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 includes underground product storage caverns; storage tanks; water wells; and related assets.

(3) Platforms and facilities includes 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 June 30, 2005 and 2004 was $79.2 million and $27.9 million, respectively. We recorded $158.1 million and $54.7 million of depreciation expense for the six months ended June 30, 2005 and 2004, respectively. Capitalized interest on our construction projects for the three months ended June 30, 2005 and 2004 was $3.2 million and $0.1 million, respectively. We recorded $7.6 million and $0.3 million of capitalized interest on our construction projects for the six months ended June 30, 2005 and 2004, respectively.

6. 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 our unconsolidated affiliates are grouped according to the business segment to which they relate. For a general discussion of our business segments, see Note 13. The following table shows our investments in and advances to unconsolidated affiliates at the dates indicated.

	Ownership Percentage at June 30, 2005	Investments in and advances to Unconsolidated Affiliates at June 30, 2005	Investments in and advances to Unconsolidated Affiliates at December 31, 2004
Offshore Pipelines & Services:			
Poseidon Oil Pipeline, L.L.C. (“Poseidon”)	36%	$ 63,531	$ 63,944
Cameron Highway Oil Pipeline Company (“Cameron Highway”) (1)	50%	64,167	114,354
Deepwater Gateway, L.L.C. (“Deepwater Gateway”)	50%	119,328	56,527
Neptune Pipeline Company, L.L.C. (“Neptune”)	25.67%	69,866	72,052
Nemo Gathering Company, LLC (“Nemo”)	33.92%	11,274	12,586
Onshore Natural Gas Pipelines & Services:			
Evangeline (2)	49.5%	3,116	2,810
Coyote Gas Treating, LLC (“Coyote”)	50%	2,006	2,441
NGL Pipelines & Services:			
Dixie Pipeline Company (“Dixie”) (3)			32,514
Venice Energy Services Company, LLC (“VESCO”)	13.1%	38,214	38,437
Belle Rose NGL Pipeline LLC (“Belle Rose”) (4)			10,172
K/D/S Promix LLC (“Promix”)	50%	60,464	65,748
Baton Rouge Fractionators LLC (“BRF”)	32.3%	26,870	27,012
Petrochemical Services:			
Baton Rouge Propylene Concentrator, LLC (“BRPC”)	30%	15,269	15,617
La Porte (5)	50%	5,041	4,950
Total		$ 479,146	$ 519,164

(1) Cameron Highway began deliveries of Gulf of Mexico crude oil production to major refining markets along the Texas Gulf Coast during the first quarter of 2005. In June 2005, we received a $47.5 million return of our investment in Cameron Highway due to the refinancing of Cameron Highway’s project debt. For additional information regarding the refinancing of Cameron Highway's debt, please read Note 10.
(2) Refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.
(3) We acquired an additional 20% ownership interest in Dixie in January 2005 and an additional 26.1% ownership interest in February 2005. As a result of these acquisitions, Dixie became a consolidated subsidiary.
(4) We acquired an additional 41.7% ownership interest in Belle Rose in June 2005. As a result of this acquisition, Belle Rose became a consolidated subsidiary.
(5) Refers to our ownership interests in La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively.

In connection with obtaining regulatory approval for the GulfTerra Merger, we were required by the U.S. Federal Trade Commission ("FTC") to sell our ownership interest in Starfish by March 31, 2005. The $36.6 million carrying value of this investment was classified as "Assets held for sale" on our balance sheet at December 31, 2004. On March 31, 2005, we sold this asset to a third-party for $42.1 million in cash and realized a gain on the sale of $5.5 million.

On occasion, the price we pay to acquire an investment exceeds the carrying value of the underlying historical net assets (i.e., the underlying equity account balances on the books of the investee) that we purchase. These excess cost amounts are a component of our investments in and advances to unconsolidated affiliates. At June 30, 2005, our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway and Nemo included excess cost. At June 30, 2005, excess cost amounts included in our investments in and advances to unconsolidated affiliates totaled $49.2 million, which was attributed to tangible assets. Amortization of our excess cost amounts attributed to tangible assets was $0.5 million and $0.4 million during the three months ended June 30, 2005 and 2004, respectively. For the six months ended June 30, 2005 and 2004, amortization of such amounts was $1.2 million and $0.9 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 June 30, 2005	For the Three Months Ended June 30, 2004	For the Six Months Ended June 30, 2005	For the Six Months Ended June 30, 2004
Offshore Pipelines & Services (1)	$ (1,075)	$ 873	$ 1,900	$ 1,856
Onshore Natural Gas Pipelines & Services	682	132	1,262	156
NGL Pipelines & Services	2,837	1,031	7,285	3,942
Petrochemical Services	137	320	413	715
Other (2)		10,712		21,266
Total	$ 2,581	$ 13,068	$ 10,860	$ 27,935

(1) Equity earnings from Cameron Highway for the three and 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 (see Note 10). The reduction in equity earnings from Cameron Highway for the three and six months ended June 30, 2005, is offset by increases in equity earnings from investments we acquired in connection with the GulfTerra Merger.

(2) This category represents equity income from GulfTerra GP. In connection with the GulfTerra Merger, GulfTerra GP became a wholly owned consolidated subsidiary on September 30, 2004. We had previously accounted for our 50% ownership interest in GulfTerra GP as an equity method investment from December 15, 2003 through September 29, 2004.

Summarized financial information of unconsolidated affiliates

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

	Summarized Income Statement Information for the Three Months Ended					
	June 30, 2005			June 30, 2004		
	Revenues	Operating Income	Net Income (Loss)	Revenues	Operating Income	Net Income
Offshore Pipelines & Services	$ 954,561	$ 19,332	$ (10,088)	$ 20,458	$ 8,621	$ 5,827
Onshore Natural Gas Pipelines & Services	82,054	4,055	1,251	69,239	3,334	1,305
NGL Pipelines & Services	69,382	14,060	14,392	52,233	6,115	6,120
Petrochemical Services	3,952	720	730	4,909	1,374	1,379

	Summarized Income Statement Information for the Six Months Ended					
	June 30, 2005			June 30, 2004		
	Revenues	Operating Income	Net Income (Loss)	Revenues	Operating Income	Net Income
Offshore Pipelines & Services	$ 1,321,396	$ 33,796	$ (1,565)	$ 35,099	$ 14,427	$ 10,471
Onshore Natural Gas Pipelines & Services	135,408	6,202	2,323	120,159	6,405	2,403
NGL Pipelines & Services	139,346	27,833	28,431	112,302	16,369	16,373
Petrochemical Services	8,047	1,848	1,871	9,551	2,918	2,919

7. INTANGIBLE ASSETS AND GOODWILL

Intangible assets

The following table summarizes our intangible assets by segment (which primarily consist of contracts and customer relationships) at the dates:

	At June 30, 2005			At December 31, 2004	
	Gross Value	Accum. Amort.	Carrying Value	Accum. Amort.	Carrying Value
Offshore Pipelines & Services	$ 207,012	$ (20,175)	$ 186,837	$ (6,965)	$ 200,047
Onshore Natural Gas Pipelines & Services	457,798	(26,695)	431,103	(8,875)	446,267
NGL Pipelines & Services	355,154	(66,607)	288,547	(53,135)	282,963
Petrochemical Services	56,674	(6,205)	50,469	(5,208)	51,324
Total	$ 1,076,638	$ (119,682)	$ 956,956	$ (74,183)	$ 980,601

During the six months ended June 30, 2005, we recorded an additional $21.9 million of intangible assets primarily due to acquisitions and changes in our fair market value estimates.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2005	2004	2005	2004
Offshore Pipelines & Services	$ 6,488		$ 13,210	
Onshore Natural Gas Pipelines & Services	8,847		17,820	
NGL Pipelines & Services	7,045	$ 3,327	13,472	$ 6,653
Petrochemical Services	508	496	997	992
Total	$ 22,888	$ 3,823	$ 45,499	$ 7,645

For the remainder of 2005, amortization expense associated with these intangible assets is currently estimated at $43.4 million.

Goodwill

The following table summarizes our goodwill amounts by segment at the dates indicated. Of the $483.4 million of goodwill we have recorded as of June 30, 2005, $381.1 million relates to goodwill we recorded in connection with the GulfTerra Merger. The amount of goodwill we recorded as a result of the GulfTerra Merger is subject to change since our purchase price allocation remains preliminary (see Note 3).

	June 30, 2005	December 31, 2004
Offshore Pipelines & Services	$ 81,114	$ 62,348
Onshore Natural Gas Pipelines & Services	278,503	290,397
NGL Pipelines & Services	50,070	32,763
Petrochemical Services	73,690	73,690
Totals	$ 483,377	$ 459,198

8. RELATED PARTY TRANSACTIONS

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2005	2004	2005	2004
Revenues from consolidated operations				
EPCO	$ 2	$ 75	$ 286	$ 2,218
Shell		144,884		248,984
Unconsolidated affiliates	80,946	57,838	138,855	106,898
Total	$ 80,948	$ 202,797	$ 139,141	$ 358,100
Operating costs and expenses				
EPCO	$ 57,129	$ 39,514	$ 114,173	$ 78,627
TEPPCO	7,146		8,649	
Shell		180,012		346,842
Unconsolidated affiliates	3,898	6,906	10,466	16,488
Total	$ 68,173	$ 226,432	$ 133,288	$ 441,957
General and administrative expenses				
EPCO	$ 10,637	$ 5,745	$ 19,888	$ 12,639

Historically, Shell Oil Company, its subsidiaries and affiliates ("Shell") were collectively considered a related party because Shell owned more than 10% of our limited partner interests and, prior to September 2003, Shell owned a 30% ownership interest in Enterprise GP. As a result of Shell selling a portion of its limited partner interests in us to third parties in December 2004 and during the first seven months of 2005, Shell now owns less than 10% of our common units. Shell sold its 30% interest in Enterprise GP to an affiliate of EPCO in September 2003. As a result of Shell's reduced equity interest in us and its lack of control of Enterprise, Shell ceased to be considered a related party beginning in the first quarter of 2005.

Relationship with EPCO. We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a non-voting director and Chairman of Enterprise GP, our general partner. In addition, the executive and other officers of Enterprise GP are employees of EPCO, including Robert G. Phillips who is President and Chief Executive Officer ("CEO") and a director of Enterprise GP. The principal business activity of Enterprise GP is to act as our managing partner.

Collectively, EPCO and its affiliates owned a 38.6% equity interest in Enterprise at June 30, 2005, which includes their ownership interest in Enterprise GP. In January 2005, an affiliate of EPCO acquired El Paso's 9.9% membership interest in Enterprise GP and 13,454,498 of our common units from El Paso for approximately $425 million in cash. As a result of these transactions, EPCO and affiliates own 100% of the membership interests of our general partner and El Paso no longer owns an interest in us or Enterprise GP.

We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the Administrative Services Agreement. 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. Additionally, we reimburse EPCO for the costs associated with the office space we occupy related to our partnership's headquarters. Our other transactions with EPCO and its affiliates include:

- 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.
- In the normal course of business, we buy from and sell certain NGL products to an affiliate of EPCO.

We and Enterprise GP are both separate legal entities from EPCO and its other affiliates, with assets and liabilities that are separate from EPCO and its other affiliates. EPCO depends on cash distributions it receives as an equity owner in us to fund most of its other operations and to meet its debt obligations. For the six months ended June 30, 2005 and 2004, EPCO affiliates received $95.2 million and $85.6 million in distributions from us, respectively. The ownership interests in us and our general partner that are owned or controlled by EPCO and its affiliates, other than Dan Duncan LLC and trusts affiliated with Dan L. Duncan, are pledged as security under an

EPCO credit facility. In the event of a default under such credit facility, a change in control of us or our general partner could occur.

Relationship with TEPPCO. On February 24, 2005, an affiliate of EPCO acquired Texas Eastern Products Pipeline Company, LLC ("TEPPCO GP"), the general partner of TEPPCO Partners, L.P. (“TEPPCO”), and 2,500,000 common units of TEPPCO from Duke Energy Field Services, LLC ("Duke Energy") for approximately $1.2 billion in cash. TEPPCO GP owns a 2% general partner interest in TEPPCO and is the managing partner of TEPPCO and its subsidiaries. Subsequently, EPCO reconstituted the board of directors of TEPPCO GP and Dr. Ralph Cunningham (a former independent director of Enterprise GP) was named Chairman of TEPPCO GP. Due to EPCO's actions to reconstitute the board of directors of TEPPCO GP and TEPPCO GP's ability to direct the management of TEPPCO, TEPPCO GP and TEPPCO became related parties to EPCO and the Company during the first quarter of 2005. The employees of TEPPCO became EPCO employees on June 1, 2005. Our significant related party transactions with TEPPCO consist of the purchase of NGL pipeline transportation and storage services.

On March 11, 2005, the Bureau of Competition of the FTC delivered written notice to EPCO’s legal advisor that it was conducting a non-public investigation to determine whether EPCO’s acquisition of TEPPCO GP may tend substantially to lessen competition. No filings were required under the Hart-Scott-Rodino Act in connection with EPCO’s purchase of TEPPCO GP. EPCO and its affiliates, including us, may receive similar inquiries from other regulatory authorities and intend to cooperate fully with any such investigations and inquiries. In response to such FTC investigation or any inquiries EPCO and its affiliates may receive from other regulatory authorities, we may be required to divest certain assets. In the event we are required to divest significant assets, our financial condition could be affected.

Relationship with unconsolidated affiliates. Our significant related party transactions with unconsolidated affiliates consist of the sale of natural gas to Evangeline, purchase of pipeline transportation services from Dixie (prior to its consolidation with our results beginning in February 2005, see Note 3) 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.

9. CAPITAL STRUCTURE

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Fourth Amended and Restated Agreement of Limited Partnership (together with all amendments thereto, the “Partnership Agreement”). Our common units trade on the NYSE under the ticker symbol “EPD.” We are managed by our general partner, Enterprise GP.

Capital accounts, under the Partnership Agreement, 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.

March 2005 universal shelf registration statement. In March 2005, we filed a universal shelf registration statement with the SEC registering the issuance of $4 billion of partnership equity and public debt obligations. In connection with this registration statement, we also registered for resale 35,368,522 common units owned by Shell and 5,631,478 common units that had been sold by Shell to Kayne Anderson MLP Investment Company in December 2004 and March 2005. We are obligated to register the resale of these common units under a registration rights agreement we executed with Shell in connection with our acquisition of certain of Shell's Gulf Coast midstream energy businesses in September 1999. We utilized $500 million of this universal shelf registration statement when our Operating Partnership issued its Senior Notes K in June 2005 (see Note 10).

Equity offerings. Our Partnership Agreement generally 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 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 from January 1, 2005 through June 30, 2005:

		Net Proceeds from Sale of Common Units		
Month of offering	Number of common units issued	Contributed by Limited Partners	Contributed by General Partner	Total
February 2005	17,250,000	$ 447,602	$ 9,135	$ 456,737
February 2005	1,516,561	38,249	780	39,029
May 2005	410,249	10,204	208	10,412
Total 2005	19,176,810	$ 496,055	$ 10,123	$ 506,178

Restricted units. At June 30, 2005, we had 495,202 restricted common units outstanding, which includes 440,902 time-vested restricted units and 54,300 performance-based restricted units. During the first six months of 2005, a total of 13,161 time-vested restricted units were issued to either key management personnel of EPCO (who work on our behalf) and directors of Enterprise GP. The aggregate fair value of these restricted units at grant date was $0.3 million. During the second quarter of 2005, 6,484 time-vested restricted units became vested and were converted to regular common units.

The balance of unamortized deferred compensation expense related to our restricted units outstanding was $9.5 million at June 30, 2005. We amortized $1.7 million of such compensation expense to earnings during the six months ended June 30, 2005, which is reflected as a component of costs and expenses. Deferred compensation is reflected as a reduction of partners' equity and allocated to our partners in accordance with their respective ownership interests.

Changes in limited partners' equity. The following table details the changes in limited partners' equity since December 31, 2004:

	Limited Partners		
	Common units	Restricted Common units	Total
Balance, December 31, 2004	$ 5,204,940	$ 12,327	$ 5,217,267
Net income	147,568	195	147,763
Operating leases paid by EPCO	1,034	1	1,035
Cash distributions to partners	(310,686)	(400)	(311,086)
Proceeds from sales of common units	496,055		496,055
Proceeds from exercise of unit options	18,645		18,645
Cancellation of treasury units	(8,915)		(8,915)
Issuance of restricted units		257	257
Vesting of restricted units	143	(143)	
Balance, June 30, 2005	$ 5,548,784	$ 12,237	$ 5,561,021

Distributions. As an incentive, Enterprise GP’s percentage interest in our quarterly cash distributions is increased after certain specified target levels of quarterly distribution rates are met. Enterprise 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.

On July 20, 2005, the Board of Directors of Enterprise GP announced that our quarterly distribution rate with respect to the second quarter of 2005 would be $0.42 per common unit, or $1.68 on an annualized basis. This distribution will be paid on August 10, 2005, to unitholders of record at the close of business on July 29, 2005.

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**	**Treasury Units**
Balance, December 31, 2004	364,297,340	488,525	427,200
Common units issued in February 2005	1,516,561		
Common units issued in connection with February 2005 offering	17,250,000		
Restricted common units issued in February 2005		12,892	
Common units issued in March 2005 in connection with unit options	195,000		
Vesting of restricted units in April 2005	6,484	(6,484)	
Cancellation of treasury units in April 2005			(427,200)
Common units issued in May 2005	410,249		
Restricted common units issued in May 2005		269	
Common units issued in May 2005 in connection with unit options	525,000		
Balance, June 30, 2005	384,200,634	495,202	-

In April 2005, we cancelled the 427,200 treasury units held by EPOLP 1999 Grantor Trust, a wholly owned subsidiary of our Operating Partnership.

Accumulated other comprehensive income. The following table summarizes the effect of our cash flow hedging financial instruments (see Note 12) on accumulated other comprehensive income (“AOCI”) since December 31, 2004.

		Interest Rate Fin. Instrs.		
	Commodity Financial Instruments	**Treasury Locks**	**Forward-Starting Interest Rate Swaps**	**Accumulated Other Comprehensive Income Balance**
Balance, December 31, 2004	$ 1,434	$ 4,572	$ 18,548	$ 24,554
Change in fair value of commodity financial instrument	(1,434)			(1,434)
Reclassification of gain on settlement of treasury locks to interest expense		(219)		(219)
Reclassification of gain on settlement of forward-starting swaps to interest expense			(1,782)	(1,782)
Balance, June 30, 2005	$ -	$ 4,353	$ 16,766	$ 21,119

During the remainder of 2005, we will reclassify a combined $2 million from accumulated other comprehensive income as a reduction in interest expense from our treasury locks and forward-starting interest rate swaps. In addition, we reclassified an approximate $1.4 million gain into income from accumulated other comprehensive income related to a commodity cash flow hedge acquired in the GulfTerra Merger. This gain is primarily due to an increase in fair value from that recorded for the commodity cash flow hedge at September 30, 2004.

10. DEBT OBLIGATIONS

Our debt consisted of the following at the dates indicated:

	June 30, 2005	December 31, 2004
Operating Partnership debt obligations:		
364-Day Acquisition Credit Facility, variable rate, repaid in February 2005 (1)		$ 242,229
Multi-Year Revolving Credit Facility, variable rate, due September 2009 (2)	$ 180,000	321,000
Seminole Notes, 6.67% fixed-rate, due December 2005 (3)	15,000	15,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Senior Notes A, 8.25% fixed-rate, repaid March 2005		350,000
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	
Senior Notes J, 5.75% fixed-rate, due March 2035	250,000	
Senior Notes K, 4.95% fixed-rate, due June 2010	500,000	
Dixie revolving credit facility, due June 2007	21,000	
GulfTerra Senior Notes and Senior Subordinated Notes (3,4)	5,673	6,469
Total principal amount	4,575,673	4,288,698
Other, including unamortized discounts and premiums and changes in fair value (5)	7,774	(7,462)
Subtotal long-term debt	4,583,447	4,281,236
Less current maturities of debt (6)	(15,000)	(15,000)
Long-term debt	$ 4,568,447	$ 4,266,236
Standby letters of credit outstanding (7)	$ 97,139	$ 139,052

(1) We used the proceeds from our February 2005 common unit offering to fully repay and terminate the 364-Day Acquisition Credit Facility. For additional information regarding this equity offering, see Note 9.
(2) The Multi-Year Revolving Credit Facility has a $750 million borrowing capacity, which is reduced by the amount of standby letters of credit outstanding.
(3) Solely as it relates to the assets of our GulfTerra, Dixie and Seminole subsidiaries, our senior indebtedness is structurally subordinated and ranks junior in right of payment to the indebtedness of such subsidiaries.
(4) GulfTerra's remaining $0.8 million of 6.25% Senior Notes due June 2010 were called and retired in February 2005.
(5) The June 30, 2005 amount includes $21.2 million related to fair value hedges and $14.6 million in net unamortized discounts.
(6) In accordance with SFAS No. 6, "*Classification of Short-Term Obligations Expected to Be Refinanced*," long-term and current maturities of debt at December 31, 2004 reflected (i) our refinancing of Senior Notes A with proceeds from our Senior Notes I and J in March 2005 and (ii) the repayment of our 364-Day Acquisition Credit Facility using proceeds from an equity offering completed in February 2005.
(7) Of the $97 million in standby letters of credit outstanding at June 30, 2005, $67 million is associated with a letter of credit facility we entered into in November 2004 in connection with our Independence Hub capital project, and the remaining amounts were issued under our Multi-Year Revolving Credit Facility. At December 31, 2004, $115 million of the $139 million of standby letters of credit outstanding was associated with the Independence Hub letter of credit facility. The decrease in standby letters of credit outstanding since December 31, 2004 under our Independence Hub letter of credit facility is the result of construction payments made by Independence Hub.

Parent-Subsidiary guarantor relationships. We act as guarantor of the debt obligations of our Operating Partnership, with the exception of the Seminole Notes, Dixie revolving credit facility and the senior subordinated notes of GulfTerra. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. The Seminole Notes are unsecured obligations of Seminole Pipeline Company (of which we own a 90% of its capital stock). The senior subordinated notes of GulfTerra are unsecured obligations of GulfTerra (of which we own 100% of its limited and general partnership interests).

Senior Notes E, F, G and H. In September 2004, our Operating Partnership priced a private offering of an aggregate of $2 billion in principal amount of senior unsecured notes in a transaction exempt from the registration requirements under the Securities Act of 1933, as amended, and in October 2004, these notes were issued. On

January 24, 2005, we filed a registration statement for an offer to exchange these notes for registered debt securities with identical terms. The exchange of notes was completed in March 2005.

Senior Notes I and J. In February 2005, our Operating Partnership sold $500 million in principal amount of senior notes in a Rule 144A private placement offering, comprised of $250 million in principal amount of 10-year senior unsecured notes and $250 million in principal amount of 30-year senior unsecured notes. The 10-year notes ("Senior Notes I") were issued at 99.379% of their principal amount and have annual fixed-rate interest of 5.00% and a maturity date of March 1, 2015. The 30-year notes ("Senior Note J") were issued at 98.691% of their principal amount and have annual fixed-rate interest of 5.75% and a maturity date of March 1, 2035. The Operating Partnership used the net proceeds from the issuance of Senior Notes I and J to repay $350 million of indebtedness outstanding under Senior Notes A which was due on March 15, 2005, and the remaining proceeds for general partnership purposes, including the temporary repayment of indebtedness outstanding under the Multi-Year Revolving Credit Facility. An offer to exchange these notes for registered debt securities began in July 2005 and is currently scheduled to expire in August 2005, unless we decide to extend it.

These fixed-rate notes are unsecured obligations of our Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness. The Operating Partnership's borrowings under these notes are non-recourse to Enterprise GP. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. These notes were issued under an indenture containing certain covenants, which restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

Senior Notes K. In June 2005, our Operating Partnership sold $500 million in principal amount of five-year senior unsecured notes. These notes were issued at 99.834% of their principal amount and have a fixed-rate interest of 4.95% and a maturity date of June 1, 2010. The Operating Partnership used the net proceeds from the issuance of these notes to temporarily reduce indebtedness outstanding under the Multi-Year Revolving Credit Facility and for general partnership purposes, including capital expenditures and business combinations. These notes were registered under the $4 billion universal shelf registration we filed in March 2005.

These fixed-rate notes are unsecured obligations of our Operating Partnership and rank equally with its existing and future unsecured and unsubordinated indebtedness. The Operating Partnership's borrowings under these notes are non-recourse to Enterprise GP. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. These notes were issued under an indenture containing certain covenants, which restrict our ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

Dixie. Dixie has a senior unsecured revolving credit facility with a borrowing capacity of $28 million. As defined by the credit agreement, variable interest rates charged under this facility generally bear interest, at our election at the time of each borrowing, at either (i) a Eurodollar rate plus an applicable margin or (ii) the greater of (a) the Prime Rate or (b) the Federal Funds Rate by 1/2%. This revolving credit agreement contains various covenants related to Dixie's ability to incur certain indebtedness; grant certain liens; enter into merger transactions; and make certain investments. The loan agreement also requires Dixie to satisfy a minimum net worth financial covenant.

Covenants. We are in compliance with the various covenants of our consolidated debt agreements at June 30, 2005 and December 31, 2004.

Information regarding variable interest rates paid. The following table shows the range of interest rates paid and weighted-average interest rate paid on our significant consolidated variable-rate debt obligations during the six months ended June 30, 2005.

	Range of interest rates paid	**Weighted-average interest rate paid**
364-Day Acquisition Credit Facility	3.25% to 3.40%	3.30%
Multi-Year Revolving Credit Facility	3.22% to 6.00%	3.64%

Consolidated debt maturity table. The following table shows scheduled maturities of the principal amounts of our debt obligations for the next 5 years and in total thereafter.

2005	$ 15,000
2007	521,000
2009	680,000
Thereafter	3,359,673
Total scheduled principal payments	$ 4,575,673

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 June 30, 2005, (ii) total long-term debt obligations (including current maturities) of each unconsolidated affiliate at June 30, 2005, on a 100% basis to the joint venture and (iii) the corresponding scheduled maturities of such long-term debt.

	Our Ownership Interest	Total	Scheduled Maturities of Long-Term Debt 2005	2006	2007	2008	2009	After 2009
Cameron Highway	50.0%	$ 415,000		$ 415,000				
Poseidon	36.0%	102,000				$ 102,000		
Evangeline	49.5%	35,650	$ 5,000	5,000	$ 5,000	5,000	$ 5,000	$ 10,650
Total		$ 552,650	$ 5,000	$ 420,000	$ 5,000	$ 107,000	$ 5,000	$ 10,650

The credit agreements of our joint ventures each contain various affirmative and negative covenants, including financial covenants. Our joint ventures were in compliance with such covenants at June 30, 2005.

Extinguishment of Deepwater Gateway credit agreement in March 2005

In accordance with terms of its credit agreement, Deepwater Gateway had the right to repay the principal amount plus any accrued interest due under its term loan at any time without penalty. During the first quarter of 2005, Deepwater Gateway exercised this right and extinguished its term loan. We and our 50% joint venture partner in Deepwater Gateway made equal cash contributions of $72 million to Deepwater Gateway to fund the repayment of the $144 million in principal amount owed under Deepwater Gateway's term loan.

Refinancing of Cameron Highway debt in June 2005

In June 2005, Cameron Highway executed an Amended and Restated Credit Agreement with a total credit commitment of $415 million and borrowed the full amount. This 364-day loan matures in June 2006 and is secured by (i) mortgages on and pledges of substantially all of the assets of Cameron Highway, (ii) mortgages on and pledges of certain assets related to certain rights of way and pipeline assets of an indirect wholly-owned subsidiary of Enterprise that serves as the operator of the Cameron Highway Oil Pipeline, (iii) pledges by Enterprise and its joint venture partner in Cameron Highway of their 50% partnership interests in Cameron Highway, and (iv) letters of credit in the amount of $14 million each issued by our Operating Partnership and an affiliate of our joint venture partner. Except for the foregoing, the Cameron Highway lenders do not have any recourse against the assets of Enterprise under the amended credit agreement.

A portion of the proceeds of the loan were used to refinance Cameron Highway’s existing $325 million project debt and to make cash distributions to the owners of Cameron Highway. In connection with this refinancing, Cameron Highway incurred approximately $22 million in one-time make whole premiums and related fees and costs, which include $6.3 million of non-cash charges. Enterprise’s equity earnings from Cameron Highway for the three and six months ended June 30, 2005 were reduced by its 50% share of such costs.

As defined in the amended credit agreement, variable interest rates charged Cameron Highway under this loan generally bear interest, at Cameron Highway’s election from time to time, at either (i) the greater of (a) the Prime Rate or (b) the Federal Funds Rate plus 1/2%, or (ii) a Eurodollar rate plus an applicable margin.

The amended credit agreement contains various covenants restricting Cameron Highway’s ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; make certain investments; make certain restricted payments; enter into certain hedging agreements; enter into certain transactions with affiliates; form any subsidiaries; make any material changes in the Cameron Highway pipeline system; enter into any sale and leaseback transaction; or enter into or amend certain other agreements. The amended loan agreement also requires Cameron Highway to satisfy certain financial covenants at the end of each fiscal quarter.

11. SUPPLEMENTAL CASH FLOWS DISCLOSURE

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

	For the Six Months Ended June 30,	
	2005	**2004**
Decrease (increase) in:		
Accounts and notes receivable	$ 65,688	$ (71,902)
Inventories	(178,770)	(51,692)
Prepaid and other current assets	(19,510)	(4,692)
Long-term receivables	127	
Other assets	30,980	(125)
Increase (decrease) in:		
Accounts payable	(114,170)	(48,013)
Accrued gas payable	(48,553)	134,674
Accrued expenses	(31,062)	(7,697)
Accrued interest	(574)	(267)
Other current liabilities	712	(1,198)
Other liabilities	(1,141)	(269)
Net effect of changes in operating accounts	$ (296,273)	$ (51,181)

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of the capital expenditures associated with such projects. As a result of completing the GulfTerra Merger, the number of such arrangements has increased, particularly for projects involving pipeline construction and production well tie-ins. These reimbursements for the six months ended June 30, 2005 and 2004, were $27 million and $0.3 million, respectively, and are reflected as a source of investing cash inflows under the caption "Contributions in aid of construction costs" on our Unaudited Condensed Statements of Consolidated Cash Flows.

Net income for the six months ended June 30, 2005 includes a gain on the sale of assets of $5.4 million (recorded as a reduction in operating costs and expenses), which is primarily related to the sale of our 50% interest in Starfish. In connection with gaining regulatory approval for the GulfTerra Merger, we were required to sell our 50% interest in Starfish by March 31, 2005.

In June 2005, we received $47.5 million in cash from Cameron Highway as a return of investment. These funds were distributed to us in connection with the refinancing of Cameron Highway’s project debt (see Note 10).

12. 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 the variability of future earnings, fair values of certain debt instruments and cash flows resulting from changes in applicable 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 rate borrowings under 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. As summarized in the following table, we had nine interest rate swap agreements outstanding at June 30, 2005 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 6.3%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 4.85%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.6% to 4.36%	$600 million

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

The total fair value of these nine interest rate swaps at June 30, 2005 and December 31, 2004, was an asset of $21.2 million and $0.5 million, respectively, with an offsetting increase in the fair value of the underlying debt. Interest expense for the three months ended June 30, 2005 and 2004 reflects a benefit of $2.9 million and $2 million, respectively, from interest rate swap agreements. For the six months ended June 30, 2005 and 2004, interest expense reflects a benefit of $7.5 million and $3.7 million, respectively, from interest rate swap agreements.

During 2004, we entered into two groups of four forward-starting interest rate swap transactions having an aggregate notional amount of $2 billion each in anticipation of our financing activities associated with the closing of the GulfTerra Merger. These interest rate swaps were accounted for as cash flow hedges and were settled during 2004 at a net gain to us of $19.4 million, which will be reclassified from accumulated other comprehensive income to reduce interest expense over the life of the associated debt.

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 natural gas and NGLs, 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 or NGLs.

At June 30, 2005 and December 31, 2004, we had a limited number of commodity financial instruments in our portfolio, which primarily consisted of natural gas cash flow and fair value hedges. The fair value of our commodity financial instrument portfolio at June 30, 2005 and December 31, 2004 was a liability of $14 thousand and an asset of $0.2 million, respectively. Excluding the reclassification of amounts from AOCI (see Note 9), we recorded nominal amounts of earnings from our commodity financial instruments during the three and six months ended June 30, 2005 and 2004.

13. BUSINESS SEGMENT INFORMATION

Business segments are components of a business about which separate financial information is available. The components are regularly evaluated by the CEO of Enterprise GP in deciding how to allocate resources and in assessing performance. Generally, financial information is required to be reported on the basis that it is used internally for evaluating segment performance and deciding how to allocate resources to segments. Our business segments are generally organized and managed according to the type of services rendered and products produced and/or sold, as applicable. We have revised our prior segment information in order to conform to the current business segment operations and presentation.

We have segregated our business activities into four reportable business segments: Offshore Pipelines & Services, Onshore Natural Gas Pipelines & Services, NGL Pipelines & Services and Petrochemical Services. The Offshore Pipelines & Services business segment consists of (i) approximately 1,150 miles of offshore natural gas pipelines strategically located to serve production areas in some of the most active drilling and development regions in the Gulf of Mexico, (ii) approximately 800 miles of Gulf of Mexico offshore crude oil pipeline systems and (iii) seven multi-purpose offshore hub platforms located in the Gulf of Mexico.

The Onshore Natural Gas Pipelines & Services business segment consists of approximately 17,200 miles of onshore natural gas pipeline systems that provide for the gathering and transmission of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas. In addition, this segment includes two salt dome natural gas storage facilities located in Mississippi, which are strategically located to serve the Northeast, Mid-Atlantic and Southeast domestic natural gas markets. This segment also includes leased natural gas storage facilities located in Texas and Louisiana.

The NGL Pipelines & Services business segment includes our (i) natural gas processing business and related NGL marketing activities, (ii) NGL pipelines aggregating approximately 12,775 miles and related storage facilities, which include our strategic Mid-America and Seminole NGL pipeline systems and (iii) NGL fractionation facilities located in Texas and Louisiana. This segment also includes our import and export terminaling operations.

The Petrochemical Services business segment includes four propylene fractionation facilities, an isomerization complex and an octane additive production facility. This segment also includes various petrochemical pipeline systems.

The Other non-segment category is presented for financial reporting purposes only to reflect the historical equity earnings we received from GulfTerra GP. We acquired a 50% membership interest in GulfTerra GP on December 15, 2003 in connection with Step One of the GulfTerra Merger. Our investment in GulfTerra GP was accounted for using the equity method until the GulfTerra Merger was completed on September 30, 2004. On that date, GulfTerra GP became a wholly owned consolidated subsidiary of ours. Since the historical equity earnings of GulfTerra GP were based on net income amounts allocated to it by GulfTerra, it is impractical for us to allocate the equity income we received during the periods presented to each of our new business segments. Therefore, we have segregated equity earnings from GulfTerra GP from our other segment results to aid in comparability between the periods presented.

Our revenues are derived from a wide customer base. All consolidated revenues were earned in the United States. Most of our plant-based operations are located either along the western Gulf Coast in Texas, Louisiana and Mississippi or in New Mexico. Our natural gas, NGL and oil pipelines and related operations are in a number of regions of the United States including the Gulf of Mexico offshore Texas and Louisiana; the south and southeastern United States (primarily in Texas, Louisiana, Mississippi and Alabama); and certain regions of the central and western United States. Our marketing activities are headquartered in Houston, Texas, at our main office and serve customers in a number of regions in the United States including the Gulf Coast, West Coast and Mid-Continent areas.

We evaluate segment performance based on segment 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.

We define total (or consolidated) segment gross operating margin as operating income before: (i) depreciation and amortization 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 intercompany transactions.

Segment revenues 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. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers, which may be a supplier of raw materials or a consumer of finished products. 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 example, we use the Promix NGL fractionator to process a portion of the mixed NGLs extracted by our gas plants. Another example was our use of the Dixie pipeline to transport propane sold to customers through our NGL marketing activities (prior to the consolidation of Dixie's results with ours beginning in February 2005, see Note 3). See Note 8 for additional information regarding our related party relationships with unconsolidated affiliates.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are allocated to each segment on the basis of each asset's or investment's principal operations. The principal reconciling item between consolidated property, plant and equipment and segment assets is construction-in-progress. Segment assets represents those facilities and projects that contribute to gross operating margin and is net of accumulated depreciation on these assets. Since assets under construction generally do not contribute to segment gross operating margin, these assets are excluded from the business segment totals until they are deemed operational. Consolidated intangible assets and goodwill are allocated 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 June 30,		For the Six Months Ended June 30,	
		2005	**2004**	**2005**	**2004**
Revenues (1)		$ 2,671,768	$ 1,713,346	$ 5,227,290	$ 3,418,236
Less:	Operating costs and expenses (1)	(2,530,133)	(1,653,317)	(4,913,777)	(3,274,825)
Add:	Equity in income of unconsolidated affiliates (1)	2,581	13,068	10,860	27,935
	Depreciation and amortization in operating costs and expenses (2)	101,048	31,715	201,013	62,235
	Retained lease expense, net in operating expenses allocable to us and minority interest (3)	528	2,273	1,056	4,547
	Loss (gain) on sale of assets in operating costs and expenses (2)	83	17	(5,353)	115
	Total gross operating margin	$ 245,875	$ 107,102	$ 521,089	$ 238,243

(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.
(3) These non-cash expenses represent the value of the operating leases contributed by EPCO to us for which EPCO has retained the cash payment obligation (i.e., the "retained leases"). The value of the retained leases contributed directly to us is shown on our Unaudited Condensed Statements of Consolidated Cash Flows under the line item titled "Operating lease expense paid by EPCO."

A reconciliation of our measurement of total segment gross operating margin to operating income and income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles follows:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Total gross operating margin	$ 245,875	$ 107,102	$ 521,089	$ 238,243
Adjustments to reconcile total gross operating margin to operating income:				
Depreciation and amortization in operating costs and expenses	(101,048)	(31,715)	(201,013)	(62,235)
Retained lease expense, net in operating costs and expenses	(528)	(2,273)	(1,056)	(4,547)
Gain (loss) on sale of assets in operating costs and expenses	(83)	(17)	5,353	(115)
General and administrative costs	(18,710)	(7,087)	(33,403)	(16,553)
Consolidated operating income	125,506	66,010	290,970	154,793
Other expense	(55,501)	(31,699)	(107,995)	(64,156)
Income before provision for income taxes, minority interest and cumulative effect of changes in accounting principles	$ 70,005	$ 34,311	$ 182,975	$ 90,637

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

	Operating Segments						
	Offshore Pipeline & Services	**Onshore Pipelines & Services**	**NGL Pipelines & Services**	**Petrochem. Services**	**Non-Segmt. Other**	**Adjustments and Eliminations**	**Consolidated Totals**
Revenues from third parties:							
Three months ended June 30, 2005	$ 31,984	$ 259,213	$ 1,945,196	$ 354,427			$ 2,590,820
Three months ended June 30, 2004		94,748	1,051,014	364,787			1,510,549
Six months ended June 30, 2005	61,532	506,147	3,802,650	717,820			5,088,149
Six months ended June 30, 2004		207,774	2,238,588	613,774			3,060,136
Revenues from related parties:							
Three months ended June 30, 2005	253	78,816	1,858	21			80,948
Three months ended June 30, 2004		56,473	143,604	2,720			202,797
Six months ended June 30, 2005	439	135,031	3,620	51			139,141
Six months ended June 30, 2004		104,437	248,535	5,128			358,100
Intersegment and intrasegment revenues:							
Three months ended June 30, 2005	432	8,400	767,030	87,137		$ (862,999)	
Three months ended June 30, 2004		2,528	320,717	65,268		(388,513)	
Six months ended June 30, 2005	628	18,417	1,496,707	141,887		(1,657,639)	
Six months ended June 30, 2004		3,337	768,281	120,579		(892,197)	
Total revenues:							
Three months ended June 30, 2005	32,669	346,429	2,714,084	441,585		(862,999)	2,671,768
Three months ended June 30, 2004		153,749	1,515,335	432,775		(388,513)	1,713,346
Six months ended June 30, 2005	62,599	659,595	5,302,977	859,758		(1,657,639)	5,227,290
Six months ended June 30, 2004		315,548	3,255,404	739,481		(892,197)	3,418,236
Equity in income in unconsolidated affiliates (see Note 6):							
Three months ended June 30, 2005	(1,075)	682	2,837	137			2,581
Three months ended June 30, 2004	873	132	1,031	320	10,712		13,068
Six months ended June 30, 2005	1,900	1,262	7,285	413			10,860
Six months ended June 30, 2004	1,856	156	3,942	715	21,266		27,935
Gross operating margin by individual business segment and in total:							
Three months ended June 30, 2005	22,034	84,903	120,328	18,610			245,875
Three months ended June 30, 2004	874	6,143	58,215	31,158	10,712		107,102
Six months ended June 30, 2005	45,258	164,261	273,632	37,938			521,089
Six months ended June 30, 2004	1,856	11,742	148,170	55,209	21,266		238,243
Segment assets:							
At June 30, 2005	636,904	3,656,480	2,933,987	500,186		455,032	8,182,589
At December 31, 2004	648,181	3,729,650	2,753,934	469,327		230,375	7,831,467
Investments in and advances to unconsolidated affiliates (see Note 6):							
At June 30, 2005	328,166	5,122	125,548	20,310			479,146
At December 31, 2004	319,463	5,251	173,883	20,567			519,164
Intangible Assets (see Note 7):							
At June 30, 2005	186,837	431,103	288,547	50,469			956,956
At December 31, 2004	200,047	446,267	282,963	51,324			980,601
Goodwill (see Note 7):							
At June 30, 2005	81,114	278,503	50,070	73,690			483,377
At December 31, 2004	62,348	290,397	32,763	73,690			459,198

Revenues from the sale and marketing of NGL products within the NGL Pipelines & Services business segment accounted for 66% and 65% of total consolidated revenues for the three months ended June 30, 2005 and 2004, and 66% and 68% for the six months ended June 30, 2005 and 2004, respectively. Revenues from the sale of petrochemical products within the Petrochemical Services segment accounted for 11% and 16% of total consolidated revenues for the three months ended June 30, 2005 and 2004, and 12% and 14% for the six months ended June 30, 2005 and 2004, respectively. Revenues from the transportation, sale and storage of natural gas using onshore assets accounted for 13% of total consolidated revenues for the second quarter of 2005 and 12% for the six months ended June 30, 2005.

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 (i.e., common and restricted common units) outstanding during a period. The distribution-bearing Class B special units were included in the calculation of basic earnings per unit prior to their conversion to common units in July 2004.

In general, diluted earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the sum of:

- the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit);
- the weighted-average number of performance-based restricted common units outstanding during a period; and
- the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the “incremental option units”).

Treasury units are not considered to be outstanding units; therefore, they are excluded from the computation of both basic and diluted earnings per unit.

In a period of net operating losses, the performance-based 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 beginning 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 allocated to limited partner interests is derived by subtracting our general partner’s share of our net income from net income. The following table shows the allocation of net income to our general partner for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2005	2004	2005	2004
Net income	$ 70,659	$ 33,148	$ 179,915	$ 95,676
Less incentive earnings allocations to Enterprise GP	(15,516)	(6,305)	(29,136)	(12,582)
Net income available after incentive earnings allocation	55,143	26,843	150,779	83,094
Multiplied by Enterprise GP ownership interest	2.0%	2.0%	2.0%	2.0%
Standard earnings allocation to Enterprise GP	$ 1,103	$ 537	$ 3,016	$ 1,662
Incentive earnings allocation to Enterprise GP	$ 15,516	$ 6,305	$ 29,136	$ 12,582
Standard earnings allocation to Enterprise GP	1,103	537	3,016	1,662
Enterprise GP interest in net income	$ 16,619	$ 6,842	$ 32,152	$ 14,244

The following tables show our calculation of limited partners' interest in net income, basic earnings per unit and diluted earnings per unit for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2005	2004	2005	2004
Income before changes in accounting principles and Enterprise GP interest	$ 70,659	$ 33,148	$ 179,915	$ 84,895
Cumulative effect of changes in accounting principles				10,781
Net income	70,659	33,148	179,915	95,676
Enterprise GP interest in net income	(16,619)	(6,842)	(32,152)	(14,244)
Net income available to limited partners	$ 54,040	$ 26,306	$ 147,763	$ 81,432
BASIC EARNINGS PER UNIT				
Numerator				
Income before changes in accounting principles and Enterprise GP interest	$ 70,659	$ 33,148	$ 179,915	$ 84,895
Cumulative effect of changes in accounting principles				10,781
Enterprise GP interest in net income	(16,619)	(6,842)	(32,152)	(14,244)
Limited partners' interest in net income	$ 54,040	$ 26,306	$ 147,763	$ 81,432
Denominator				
Common units outstanding	383,734	225,744	378,376	219,897
Restricted common units outstanding	495	31	495	15
Class B special units outstanding		4,414		4,414
Total	384,229	230,189	378,871	224,326
Basic earnings per unit				
Income per unit before changes in accounting principles and Enterprise GP interest	$ 0.18	$ 0.14	$ 0.47	$ 0.38
Cumulative effect of changes in accounting principles				0.05
Enterprise GP interest in net income	(0.04)	(0.03)	(0.08)	(0.06)
Limited partners' interest in net income	$ 0.14	$ 0.11	$ 0.39	$ 0.37
DILUTED EARNINGS PER UNIT				
Numerator				
Income before changes in accounting principles and Enterprise GP interest	$ 70,659	$ 33,148	$ 179,915	$ 84,895
Cumulative effect of changes in accounting principles				10,781
Enterprise GP interest in net income	(16,619)	(6,842)	(32,152)	(14,244)
Limited partners' interest in net income	$ 54,040	$ 26,306	$ 147,763	$ 81,432
Denominator				
Common units outstanding	383,734	225,744	378,376	219,897
Restricted common units outstanding	495	31	495	15
Class B special units outstanding		4,414		4,414
Performance-based restricted units	54		54	
Incremental option units	526	436	612	496
Total	384,809	230,625	379,537	224,822
Diluted earnings per unit				
Income per unit before changes in accounting principles and Enterprise GP interest	$ 0.18	$ 0.14	$ 0.47	$ 0.38
Cumulative effect of changes in accounting principles				0.05
Enterprise GP interest in net income	(0.04)	(0.03)	(0.08)	(0.06)
Limited partners' interest in net income	$ 0.14	$ 0.11	$ 0.39	$ 0.37

15. CONDENSED FINANCIAL INFORMATION OF OPERATING PARTNERSHIP

The Operating Partnership and its subsidiaries conduct substantially all of our business. Currently, we have no independent operations and no material assets outside of those of our wholly owned Operating Partnership. We act as guarantor of all our Operating Partnership's consolidated debt obligations, with the exception of the Seminole Notes, the Dixie revolving credit facility and the remaining amounts outstanding under GulfTerra's senior subordinated notes. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. Our guarantee of these debt obligations is full and unconditional. For additional information regarding our consolidated debt obligations, see Note 10.

The number and dollar amounts of reconciling items between our consolidated financial statements and those of our Operating Partnership are insignificant. Historically, the primary reconciling items between the consolidated balance sheet of the Operating Partnership and our consolidated balance sheet were treasury units we owned directly and minority interest. The differences in consolidated net income were primarily dividends recognized by the 1999 Trust (which are eliminated in consolidation) and minority interest.

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

	June 30, 2005	December 31, 2004
ASSETS		
Current assets	$ 1,530,883	$ 1,425,574
Property, plant and equipment, net	8,182,589	7,831,467
Investments in and advances to unconsolidated affiliates, net	479,146	519,164
Intangible assets, net	956,956	980,601
Goodwill	483,377	459,198
Deferred tax asset	7,737	6,467
Long-term receivables	14,815	14,931
Other assets	48,062	43,208
Total	$ 11,703,565	$ 11,280,610
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities	$ 1,330,039	$ 1,582,911
Long-term debt	4,568,447	4,266,236
Other long-term liabilities	58,708	63,521
Minority interest	88,503	73,858
Partners' equity	5,657,868	5,294,084
Total	$ 11,703,565	$ 11,280,610
Total Operating Partnership debt obligations guaranteed by us	$ 4,534,000	$ 4,267,229

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2005	2004	2005	2004
Revenues	$ 2,671,768	$ 1,713,346	$ 5,227,290	$ 3,418,236
Costs and expenses	2,548,221	1,660,018	4,945,867	3,290,729
Equity in income of unconsolidated affiliates	2,581	13,068	10,860	27,935
Operating income	126,128	66,396	292,283	155,442
Other income (expense)	(55,741)	(31,540)	(108,216)	(63,839)
Income before provision for income taxes, minority interest and changes in accounting principles	70,387	34,856	184,067	91,603
Provision for income taxes	1,034	(419)	(735)	(2,044)
Income before minority interest and changes in accounting principles	71,421	34,437	183,332	89,559
Minority interest	(392)	(714)	(2,333)	(3,648)
Income before changes in accounting principles	71,029	33,723	180,999	85,911
Cumulative effect of changes in accounting principles				10,781
Net income	$ 71,029	$ 33,723	$ 180,999	$ 96,692

16. COMMITMENTS AND CONTINGENCIES

Operating leases. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Our material agreements consist of operating leases, with original terms ranging from 5 to 24 years, for natural gas and NGL underground storage facilities. We generally have the option to renew these leases, under the terms of the agreements, for one or more renewal terms ranging from 2 to 10 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. Third-party lease and rental expense included in operating income for the three months ended June 30, 2005 and 2004 was approximately $8.4 million and $5.4 million, respectively. We recorded $17.1 million and $10.3 million of third-party lease and rental expense for the six months ended June 30, 2005 and 2004, respectively.

Litigation. We are sometimes named as a defendant in litigation relating to our normal business operations, including litigation related to various federal, state and local regulatory and environmental matters. Although we insure against various business risks, to the extent management believes 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 ordinary business activity. Management is not aware of any significant litigation, pending or threatened, that would have a significant adverse effect on our financial position or results of operations.

We own an octane-additive production facility that historically produced, and is currently capable of producing, methyl tertiary butyl ether ("MTBE"), a motor gasoline additive that enhances octane and is used in reformulated motor gasoline. We operate the facility, which is located within our Mont Belvieu complex. The production of MTBE was primarily driven by oxygenated fuel programs enacted under the federal Clean Air Act Amendments of 1990. In recent years, MTBE has been detected in water supplies. The major source of ground water contamination appears to be leaks from underground storage tanks. As a result of environmental concerns, several states enacted legislation to ban or significantly limit the use of MTBE in motor gasoline within their jurisdictions. The Energy Bill approved by the U.S. Congress in July 2005 (and awaiting the President's signature) eliminates oxygenates in motor gasoline.

A number of lawsuits have been filed by municipalities and other water suppliers against a number of manufacturers of reformulated gasoline containing MTBE, although generally such suits have not named manufacturers of MTBE as defendants, and there have been no such lawsuits filed against our subsidiary which owns the facility. It is possible, however, that MTBE manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits. In connection with our purchase of ownership interests in the octane-additive production facility in 2003 from an affiliate of Devon Energy Corporation ("Devon") and in

2004 from an affiliate of Sunoco, Inc. (“Sun”), Devon and Sun indemnified us for any liability (including liabilities described above) that are in respect of periods prior to the date we purchased such interests.

Performance Guaranty. In December 2004, our Independence Hub, LLC subsidiary entered into the Independence Hub Agreement (the "Agreement") with six oil and natural gas producers. The Agreement obligates Independence Hub, LLC (i) to construct an offshore platform production facility to process 850 MMcf/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 Agreement, our Operating Partnership guaranteed the performance of its Independence Hub, LLC subsidiary under the Agreement up to $397.5 million. In December 2004, 20% of this guaranteed amount was assumed by Cal Dive, our joint venture partner in the Independence Hub project. The remaining $318 million represents our share of the anticipated cost of the platform facility. This amount represents the cap on our Operating Partnership's potential obligation to the six producers for our share of the cost of constructing the platform in the very unlikely scenario where the six producers take over the construction of the platform facility. Our performance guarantee continues until the earlier to occur of (i) all of the guaranteed obligations of Independence Hub, LLC shall have been terminated or expired, or shall have been indefeasibly paid or otherwise performed or discharged in full, (ii) upon mutual written consent of our Operating Partnership and the producers or (iii) mechanical completion of the production facility. We expect that mechanical completion will occur on or about November 1, 2006; therefore, we anticipate that the performance guaranty will exist until at least this future date.

In accordance with FIN 45, 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 the guaranty, we have estimated the fair value of the performance guaranty at approximately $1.2 million, which is a component of current and other long-term liabilities on our unaudited condensed consolidated balance sheet at June 30, 2005.

17. SUBSEQUENT EVENTS

Purchase of NGL underground storage and terminaling assets

In July 2005, we purchased three NGL underground storage facilities and four terminals from Ferrellgas L.P. for $144 million in cash. The underground storage facilities are located in Kansas, Arizona and Utah and have a combined capacity of 6.1 MMBbls. Approximately 70% of the aggregate storage capacity is leased to third party customers under fee-based contracts. The four propane terminals are located in Minnesota and North Carolina. The Minnesota facilities are connected to our Mid-America pipeline system, and the North Carolina terminals are connected by rail to our facilities on the Gulf Coast. As part of the transaction, Ferrellgas has contracted with us to maintain a certain level of storage volume and terminal throughput for five years with the option to extend for an additional five years.

August 2005 interest rate swaps

In August 2005, we entered into two interest rate swap agreements with an aggregate notional amount of $200 million in which we exchanged the payment of fixed rate interest on a portion of the principal outstanding under Senior Notes K for variable rate interest. We have designated these two interest rate swaps as fair value hedges under SFAS No. 133 since they mitigate changes in the fair value of the underlying fixed rate debt. Under each swap agreement, we will pay the counterparty a variable interest rate based on six-month LIBOR rates (plus an applicable margin as defined in each swap agreement) and receive back from the counterparty a fixed interest rate payment of 4.95%, which is the stated interest rate of Senior Notes K. We will settle amounts receivable from or payable to the counterparty every six months (the "settlement period"), with the first settlement occurring on December 1, 2005. The settlement amount will be amortized ratably to earnings as either an increase or a decrease in interest expense over the settlement period.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

For the three and six months ended June 30, 2005 and 2004.

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

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 GP"). We and Enterprise GP are affiliates of EPCO, Inc. ("EPCO").

The following discussion and analysis should be read in conjunction with our unaudited consolidated financial statements and notes included under Item 1 of this quarterly report on Form 10-Q.

As used in this discussion, "GulfTerra Merger" refers to the merger of GulfTerra Energy Partners, L.P. with a wholly owned subsidiary of Enterprise on September 30, 2004 and the various transactions related thereto. References to "GulfTerra" mean Enterprise GTM Holdings L.P., the successor to GulfTerra Energy Partners, L.P. References to "GulfTerra GP" mean Enterprise GTMGP, L.L.C., which was formerly known as GulfTerra Energy Company, L.L.C., the general partner of GulfTerra Energy Partners L.P. Enterprise GTMGP, L.L.C. is the general partner of Enterprise GTM Holdings L.P.

Unless otherwise indicated, the dollar amounts presented in the tabular data within this discussion and analysis are stated in thousands of dollars.

In addition, as generally used in the energy industry and in this discussion and analysis, the identified terms have the following meanings:

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

This quarterly report contains various forward-looking statements and information that are based on our beliefs and those of Enterprise GP, our general partner, as well as assumptions made by us and information currently available to us. Please read "*Cautionary Statement Regarding Forward-Looking Statements and Risk Factors*" for additional information.

RECENT DEVELOPMENTS

The following summarizes our recent significant developments since December 31, 2004.

- In January 2005, affiliates of EPCO acquired a 9.9% membership interest in Enterprise GP and 13,454,498 of our common units from El Paso for approximately $425 million in cash. As a result of these transactions, EPCO and its affiliates own 100% of the membership interests of Enterprise GP.

- In January 2005, we paid $74.5 million for an indirect 80% equity interest in the 89-mile Indian Springs Gathering System and an indirect 75% equity interest in the Indian Springs natural gas processing facility, both of which are located in East Texas.

- In January 2005, we purchased an approximate 20% interest in Dixie Pipeline Company (“Dixie”) for $31 million. Additionally, we purchased an approximate 26% interest in Dixie in February 2005 for $40 million. We currently own approximately 66% of Dixie.

- In February 2005, we sold 17,250,000 common units (including the over-allotment amount of 2,250,000 common units which closed on March 11, 2005), which generated net proceeds of approximately $456.7 million.

- In February 2005, our Operating Partnership sold $500 million in principal amount of senior notes in a private offering, comprised of $250 million in principal amount of our 10-year Senior Notes I and $250 million in principal amount of our 30-year Senior Notes J.

- In March 2005, we filed a universal shelf registration statement with the U.S. Securities and Exchange Commission ("SEC") registering the issuance of $4 billion of partnership equity and public debt obligations. In June 2005, our Operating Partnership sold $500 million in principal amount of 4.95% senior notes due June 2010 (“Senior Notes K”) under this universal shelf registration statement.

- In April 2005, an affiliate of EPCO, Enterprise GP Holdings L.P., was formed to become the sole member of Enterprise GP and to own 13.5 million of our common units that will at some time in the future, be contributed to it by other affiliates of EPCO. In connection with its formation, Enterprise GP Holdings L.P. filed a registration statement on Form S-1 for an initial public offering of its common units on April 26, 2005, which was amended on June 21, 2005 and July 21, 2005. The completion of this offering, which is expected to occur in the second half of 2005, will result in Enterprise GP Holdings L.P. owning our general partner, and EPCO and its affiliates owning approximately 86.6% of the equity interests in Enterprise GP Holdings L.P.

- Cameron Highway Oil Pipeline Company ("Cameron Highway") began deliveries of Gulf of Mexico crude oil production to major refining markets along the Texas Gulf Coast during the first quarter of 2005. The Cameron Highway Oil Pipeline is designed to gather production from the deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in Port Arthur and Texas City, Texas. This pipeline can currently transport up to 500 MBPD of crude oil production. We own a 50% equity interest in Cameron Highway.

- In June 2005, we announced our plans to construct a new NGL fractionator near Hobbs, New Mexico and to expand our Mid-America pipeline system from Hobbs, New Mexico to Conway, Kansas. See “-- *Our Capital Spending*” for additional information regarding these growth projects.

- In June 2005, we exercised our option to acquire a 2% indirect ownership interest in the Mid-America pipeline and a 1.6% indirect ownership interest in the Seminole pipeline for a total purchase price of $25 million. This transaction was completed on June 30, 2005, and as a result, we now own 100% of the Mid-America pipeline and 90% of the Seminole pipeline.

- In July 2005, we purchased three NGL underground storage facilities and four terminals from Ferrellgas L.P. (“Ferrellgas”) for $144 million in cash. See “-- *Our Capital Spending*” for additional information regarding this acquisition.

- In August 2005, we entered into two interest rate swap agreements with an aggregate notional amount of $200 million in which we exchanged the payment of fixed rate interest on a portion of the principal outstanding under Senior Notes K for variable rate interest. For additional information regarding these interest rate swap agreements, please read “*Quantitative and Qualitative Disclosures about Market Risk*” included under Item 3 of this quarterly report on Form 10-Q.

OUR CAPITAL SPENDING

We are committed to the long-term growth and viability of the Company. Part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. 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. Management continues to analyze potential acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions.

We believe that we are positioned to continue to grow through acquisitions that will expand our system of assets and through growth capital projects. The combination of our operations with those of GulfTerra provides us with incremental growth opportunities for both onshore and offshore projects. We estimate our total capital spending during the second half of 2005 will approximate $680 million, which includes estimated expenditures of $630 million for growth capital projects and acquisitions and approximately $50 million for sustaining capital expenditures for anticipated improvements to and major renewals of existing assets. Our estimate of $630 million in growth capital spending for the second half of 2005 includes the $144 million in cash we paid to acquire assets from Ferrellgas in July 2005.

The ability to execute our growth strategy and complete our projects is dependent upon our access to the capital necessary to fund projects and acquisitions. Our success with capital raising efforts, including the formation of joint ventures to share costs and risks, continues to be the critical factor that determines how much we actually 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 as necessary to adapt to changes in the capital markets.

We estimate our forecasted expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to provide capital from operating cash flows or otherwise obtain the capital necessary to accomplish our operating and growth objectives. These estimates may change due to factors beyond our control, such as weather related issues, changes in supplier prices or poor economic conditions. Further, estimates may change as a result of decisions made at a later date, which may include acquisitions or decisions to take on additional partners.

The following table summarizes our capital spending by activity for the periods indicated:

	For the Six Months Ended June 30,	
	2005	2004
Capital spending for business combinations:		
Indirect interests in the Indian Springs natural gas gathering and processing assets	$ 74,854	
Additional ownership interests in Dixie Pipeline Company ("Dixie")	68,608	
Additional ownership interests in Mid-America and Seminole pipeline systems	25,000	
Additional ownership interest in Seminole Pipeline Company ("Seminole")		$ 28,600
Additional ownership interest in Tri-States NGL Pipeline LLC ("Tri States")	900	16,485
Other business combinations	11,717	
Total capital spending related to business combinations	181,079	45,085
Capital spending for property, plant and equipment:		
Growth capital projects	371,894	18,026
Sustaining capital projects	36,843	9,889
Total capital spending for property, plant and equipment	408,737	27,915
Capital spending attributable to unconsolidated affiliates:		
Investments in unconsolidated affiliates, excluding advances	80,650	468
Total capital spending	$ 670,466	$ 73,468

Capital spending for property, plant and equipment as shown in the preceding table, is shown net of contributions in aid of construction costs of $27 million and $0.3 million for the six months ended June 30, 2005 and 2004, respectively.

At June 30, 2005, we had approximately $116.4 million in outstanding purchase commitments related to capital projects, the majority of which pertain to pipeline and platform growth projects in the Gulf of Mexico that are expected to be placed in service during 2005 and 2006.

Significant Announced Growth Capital Projects

Western Expansion Project – NGL fractionation. In June 2005, we announced our 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 system near Hobbs, New Mexico. Additionally, we will construct a purity ethane storage well near the new fractionator and reconfigure the interconnection between the Mid-America pipeline and the Seminole pipeline. These projects are expected to cost approximately $130 million and be placed in service by mid-2007.

In January 2005, we announced that we had commenced initial permitting, engineering and design work for our Western Expansion Project, which included adding 50 MBPD of transportation capacity on the Rocky Mountain segment of our Mid-America pipeline system and a new 60 MBPD NGL fractionator at our Mont Belvieu complex. After additional analysis, we decided to build the new fractionator at Hobbs (as described in the previous paragraph) instead of the previously announced 60 MBPD fractionator at our Mont Belvieu complex because the Hobbs fractionator will provide a more strategic solution for the handling of increased Rocky Mountain volumes.

Expansion of Mid-America pipeline system. In June 2005, we announced that we had started 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 30 MBPD from Skellytown, Texas to Hobbs, New Mexico. Construction of this pipeline will begin in mid-2006 and is expected to be in service in the first quarter of 2007.

Purchase of NGL underground storage and terminaling assets. In July 2005, we purchased three NGL underground storage facilities and four terminals from Ferrellgas for $144 million in cash. The underground storage facilities are located in Kansas, Arizona and Utah and have a combined capacity of 6.1 MMBbls. Approximately 70% of the aggregate storage capacity is leased to third party customers under fee-based contracts. The four propane terminals are located in Minnesota and North Carolina. The Minnesota facilities are connected to our Mid-

America pipeline system, and the North Carolina terminals are connected by rail to our facilities on the Gulf Coast. As part of the transaction, Ferrellgas has contracted with us to maintain a certain level of storage volume and terminal throughput for five years with the option to extend for an additional five years.

OUR RESULTS OF OPERATIONS

We have four reportable business segments: Offshore Pipelines & Services, Onshore Natural Gas Pipelines & Services, NGL 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.

The Offshore Pipelines & Services business segment consists of (i) approximately 1,150 miles of offshore natural gas pipelines strategically located to serve production areas in some of the most active drilling and development regions in the Gulf of Mexico, (ii) approximately 800 miles of Gulf of Mexico offshore crude oil pipeline systems and (iii) seven multi-purpose offshore hub platforms located in the Gulf of Mexico.

The Onshore Natural Gas Pipelines & Services business segment consists of approximately 17,200 miles of onshore natural gas pipeline systems that provide for the gathering and transmission of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas. In addition, this segment includes two salt dome natural gas storage facilities located in Mississippi, which are strategically located to serve the Northeast, Mid-Atlantic and Southeast domestic natural gas markets. This segment also includes leased natural gas storage facilities located in Texas and Louisiana.

The NGL Pipelines & Services business segment includes our (i) natural gas processing business and related NGL marketing activities, (ii) NGL pipelines aggregating approximately 12,775 miles and related storage facilities, which include our strategic Mid-America and Seminole NGL pipeline systems and (iii) NGL fractionation facilities located in Texas and Louisiana. This segment also includes our import and export terminaling operations.

The Petrochemical Services business segment includes four propylene fractionation facilities, an isomerization complex and an octane additive production facility. This segment also includes various petrochemical pipeline systems.

The Other non-segment category is presented for financial reporting purposes only to reflect the historical equity earnings we received from GulfTerra GP. We acquired a 50% membership interest in GulfTerra GP on December 15, 2003, in connection with the GulfTerra Merger. Our investment in GulfTerra GP was accounted for using the equity method until the GulfTerra Merger was completed on September 30, 2004. On that date, GulfTerra GP became a wholly owned consolidated subsidiary of ours. Since the historical equity earnings of GulfTerra GP were based on net income amounts allocated to it by GulfTerra, it is impractical for us to allocate the equity income we received during the periods presented to each of our new business segments. Therefore, we have segregated equity earnings from GulfTerra GP from our other segment results to aid in comparability between the periods presented.

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 and amortization 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 intercompany transactions.

We have historically included equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers, which may be suppliers of raw materials or consumers of finished products. 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 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Selected Price and Volumetric Data

The following table illustrates selected average quarterly industry index prices for natural gas, crude oil, selected NGL and petrochemical products since the beginning of 2004:

	Natural Gas, $/MMBtu	Crude Oil, $/barrel	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	Polymer Grade Propylene, $/pound	Refinery Grade Propylene, $/pound
	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
2004									
1st Quarter	$5.69	$35.25	$0.43	$0.66	$0.76	$0.76	$0.87	$0.29	$0.26
2nd Quarter	$6.00	$38.34	$0.45	$0.65	$0.79	$0.79	$0.92	$0.32	$0.26
3rd Quarter	$5.75	$43.90	$0.52	$0.79	$0.92	$0.92	$1.05	$0.32	$0.27
4th Quarter	$7.07	$48.31	$0.60	$0.85	$1.03	$1.04	$1.15	$0.40	$0.35
Average for Year	$6.13	$41.45	$0.50	$0.74	$0.88	$0.88	$1.00	$0.33	$0.29
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
Average for Year	$6.51	$51.39	$0.52	$0.81	$0.98	$1.01	$1.15	$0.41	$0.35

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

The following table presents our significant average throughput, production and processing volumetric data for the periods indicated (on a net basis, taking into account our ownership interests). In general, the increase in volumes period-to-period is primarily due to the assets we acquired in connection with the GulfTerra Merger, including the South Texas midstream assets. The GulfTerra Merger was completed on September 30, 2004.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2005 (1)	**2004** (1)	**2005** (1)	**2004** (1)
Offshore Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	2,156	448	2,004	439
Crude oil transportation volumes (MBPD)	151		139	
Platform gas treating (Mdth/d)	319		317	
Platform oil treating (MBPD)	7		8	
Onshore Natural Gas Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	6,015	620	5,881	633
NGL Pipelines & Services, net:				
NGL transportation volumes (MBPD)	1,511	1,254	1,461	1,311
NGL fractionation volumes (MBPD)	327	237	332	233
Equity NGL production (MBPD)	100	46	100	47
Fee-based natural gas processing (MMcf/d)	2,001	1,248	2,009	805
Petrochemical Services, net:				
Butane isomerization volumes (MBPD)	84	78	75	69
Propylene fractionation volumes (MBPD)	56	60	55	57
Octane additive production volumes (MBPD)	8	10	4	7
Petrochemical transportation volumes (MBPD)	72	77	73	70
Total, net:				
NGL, crude oil and petrochemical transportation volumes (MBPD)	1,734	1,331	1,673	1,381
Natural gas transportation volumes (BBtus/d)	8,171	1,068	7,885	1,072
Equivalent transportation volumes (MBPD) (2)	3,884	1,612	3,748	1,663

(1) Volumetric data shown above reflects net operating rates of the underlying assets for the periods in which we owned them.
(2) Reflects equivalent energy volumes where 3.8 MMBtus of natural gas are equivalent to one barrel of NGLs.

Comparisons of Our Results of Operations

The following table summarizes the key components of our results of operations for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Revenues	$ 2,671,768	$ 1,713,346	$ 5,227,290	$ 3,418,236
Operating costs and expenses	2,530,133	1,653,317	4,913,777	3,274,825
General and administrative costs	18,710	7,087	33,403	16,553
Equity in income of unconsolidated affiliates	2,581	13,068	10,860	27,935
Operating income	125,506	66,010	290,970	154,793
Interest expense	56,746	31,867	110,159	64,485
Net income	70,659	33,148	179,915	95,676

Revenues from the sale and marketing of NGL products within the NGL Pipelines & Services business segment accounted for 66% and 65% of total consolidated revenues for the three months ended June 30, 2005 and 2004, and 66% and 68% for the six months ended June 30, 2005 and 2004, respectively. Revenues from the sale of petrochemical products within the Petrochemical Services segment accounted for 11% and 16% of total consolidated revenues for the three months ended June 30, 2005 and 2004, and 12% and 14% for the six months ended June 30, 2005 and 2004, respectively. Revenues from the transportation, sale and storage of natural gas using onshore assets accounted for 13% of total consolidated revenues for the second quarter of 2005 and 12% for the six months ended June 30, 2005.

In general, an increase in our revenues and costs and expenses period-to-period is attributable to the results of businesses acquired or consolidated since June 30, 2004. In addition, higher energy commodity prices result in increased revenues from our NGL and petrochemical marketing activities; however, these same higher prices also increase the cost of sales within these activities as feedstock and other related purchase prices rise. For selected general energy commodity price information and detailed segment-level volumetric information, please review the tables under "*—Selected Price and Volumetric Data*."

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2005	2004	2005	2004
Gross operating margin by segment:				
Offshore Pipelines & Services	$ 22,034	$ 874	$ 45,258	$ 1,856
Onshore Natural Gas Pipelines & Services	84,903	6,143	164,261	11,742
NGL Pipelines & Services	120,328	58,215	273,632	148,170
Petrochemical Services	18,610	31,158	37,938	55,209
Other, non-segment		10,712		21,266
Total segment gross operating margin	$ 245,875	$ 107,102	$ 521,089	$ 238,243

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 the cumulative effect of changes in accounting principles, please read "*Other Items*" included within this Item 2.

Three Months Ended June 30, 2005 Compared with the Three Months Ended June 30, 2004

The weighted-average market price for NGLs was 81 cents per gallon for the three months ended June 30, 2005 versus 66 cents per gallon during the same period in 2004—a quarter-to-quarter increase of 23%. Our determination of the weighted-average market price for NGLs is based on selected U.S. Gulf Coast prices for such products at Mont Belvieu, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub) averaged $6.74 per MMBtu for the second quarter of 2005 versus $6.00 per MMBtu during the 2004 period. Polymer grade propylene index prices increased 16% quarter-to-quarter and refinery grade propylene index prices increased 15% quarter-to-quarter.

Revenues for the second quarter of 2005 increased $958 million over those recorded during the same period in 2004. In general, the trend in consolidated revenues can be attributed to (i) a $457 million increase in revenues from our NGL and petrochemical marketing activities primarily resulting from an increase in overall sales volumes and energy commodity market prices and (ii) the addition of $480 million in revenues from businesses acquired or consolidated since June 30, 2004, which primarily include GulfTerra and the South Texas midstream assets.

Consolidated costs and expenses increased $877 million quarter-to-quarter primarily due to (i) an increase in volumes purchased including the effects of higher product prices, which resulted in a $391 million increase in the cost of sales of our NGL and petrochemical marketing activities and (ii) the addition of $360 million in costs and expenses attributable to businesses acquired or consolidated since June 30, 2004. General and administrative costs also increased $11.6 million quarter-to-quarter primarily due to businesses acquired since June 30, 2004.

Equity earnings from unconsolidated affiliates decreased $10.5 million quarter-to-quarter primarily due to an $11.5 million charge recorded in the second quarter of 2005 associated with the refinancing of Cameron Highway's project debt. Equity earnings for the second quarter of 2005 includes our share of earnings from investments we acquired in connection with the GulfTerra Merger. The second quarter of 2004 includes $10.7 million of equity earnings from GulfTerra GP, which we began consolidating on September 30, 2004 as a result of completing the GulfTerra Merger. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to a $59.5 million increase in operating income quarter-to-quarter.

The $24.9 million increase in interest expense is primarily due to additional debt we incurred in October 2004 as a result of the GulfTerra Merger (Senior Notes E, F, G and H), Senior Notes I and J in February 2005 and Senior Notes K in June 2005. Our weighted-average debt principal outstanding was $4.5 billion during the second quarter of 2005 compared to $2 billion during the second quarter of 2004.

As a result of the items noted in previous paragraphs, our net income increased $37.5 million to $70.7 million for the second quarter of 2005 from $33.1 million for the second quarter of 2004.

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

Offshore Pipelines & Services. Gross operating margin from this business segment increased $21.2 million quarter-to-quarter primarily due to offshore Gulf of Mexico assets acquired in connection with the GulfTerra Merger. These assets accounted for $17.3 million of gross operating margin recorded for this segment during the second quarter of 2005. Additionally, gross operating margin for the second quarter of 2005 includes a one-time benefit of $5.1 million from the resolution of a transportation contract dispute relating to our Neptune investment and an $11.5 million one-time charge related to Cameron Highway's debt restructuring. For additional information regarding Cameron Highway's debt restructuring, please read Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Our Cameron Highway oil pipeline benefited from increased transportation volumes during the second quarter of 2005 due to the connection of additional wells in the Mad Dog and Holstein developments to this system. We expect additional wells in these production fields to be connected to the Cameron Highway oil pipeline during the third quarter of 2005. Also, the first well in the K-2 deepwater Gulf of Mexico production field was connected to our Marco Polo platform and related pipeline assets during the second quarter of 2005. We expect that additional wells from the K-2 and the K-2 North fields will be connected to the Marco Polo assets during the third and fourth quarters of 2005.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment increased $78.8 million quarter-to-quarter primarily due to onshore natural gas pipeline and storage assets we acquired in connection with the GulfTerra Merger. These assets accounted for $79 million of gross operating margin recorded for this segment during the second quarter of 2005.

Our Texas Intrastate System generated gross operating margin of $27.9 million during the second quarter of 2005 on average transportation volumes of 3,526 BBtus/d. The Texas Intrastate System is an 8,222-mile natural gas pipeline system that gathers and transports natural gas from supply basins in Texas and offshore in the Gulf of Mexico to local gas distribution companies and electric generation and industrial customers. Our San Juan Gathering System contributed $40 million of gross operating margin during the second quarter of 2005 on average transportation volumes of 1,178 BBtus/d. The San Juan Gathering System is a 5,404-mile natural gas pipeline system that serves natural gas producers in the San Juan Basin of New Mexico and Colorado. We own 100% of the Texas Intrastate System and the San Juan Gathering System, both of which were acquired in connection with the GulfTerra Merger.

NGL Pipelines & Services. Gross operating margin from this business segment increased $62.1 million quarter-to-quarter primarily due to contributions from assets we acquired in connection with the GulfTerra Merger, including the South Texas midstream assets, and improved processing economics. Gross operating margin from natural gas processing assets we have acquired since June 30, 2004 accounted for approximately $40.4 million of the increase in gross operating margin for this segment. Gross operating margin from our NGL marketing activities and Louisiana natural gas processing facilities increased $8 million quarter-to-quarter primarily due to higher NGL prices and equity NGL production rates. Our natural gas processing business benefited from increased demand for NGLs by the petrochemical and motor gasoline industries.

Gross operating margin from NGL pipelines and related storage services increased $8.5 million quarter-to-quarter. Improved gross operating margin from our Mid-America and Seminole pipelines and NGL import facility, including related assets, were partially offset by lower returns from our NGL storage facilities and a $4.3 million charge in May 2005 related to off specification propane injected into our Dixie pipeline. During the second quarter of 2005, propane that did not meet Dixie's quality specifications was injected by third parties into the Dixie pipeline, which required the pipeline to be taken out of service for approximately one month while the affected propane was removed and the pipeline was cleaned. The pipeline was returned to service on June 1, 2005. Dixie will seek to recover the $4.3 million in costs from any responsible parties. Enterprise owns an approximate 66% interest in

Dixie, which was consolidated for financial reporting purposes beginning in the first quarter of 2005 as a result of our acquisition of additional ownership interests in Dixie.

Gross operating margin from NGL fractionation increased $9.1 million quarter-to-quarter primarily due to NGL fractionation assets we acquired in connection with the GulfTerra Merger. Expenses related to support services classified within this segment (e.g., product distribution and related business management costs) increased $3.9 million quarter-to-quarter primarily due to increased business activities related to acquired assets.

One of our objectives for 2005 was to seek relief through filings with the FERC to increase tariffs on our Mid-America and Seminole pipeline systems to recover increased costs of operating the pipelines, principally those costs attributable to fuel and pipeline integrity expenses. In March 2005, the joint tariff rate for Mid-America and Seminole increased, which should result in additional revenues of approximately $10 million per year on a combined basis for these assets based on expected transportation rates. In May 2005, the FERC allowed a cost of service increase in Mid-America's local tariffs (subject to refund and further review), that is expected to provide our Mid-America pipeline additional revenues of approximately $12 million per year based on expected transportation rates. This cost of service adjustment has been protested by shippers, so although the increased rates are being collected from customers, revenue related to this cost of service adjustment is being deferred. If these protests are settled in favor of Mid-America during 2005, the deferred revenues will be recognized in earnings at that time. If these protests are settled in favor of the shippers, the deferred revenue amount will be refunded. As of June 30, 2005, $1.3 million in revenues associated with this cost of service adjustment have been deferred.

In addition to the above rate changes, in July 2005, Mid-America voluntarily filed a new tariff with the FERC, which reduced certain transportation rates for mixed NGL product movements from the northern Rockies to Mont Belvieu, Texas. The new tariff is currently being reviewed by the FERC. We filed this new tariff, which is a discount to our general commodity rate, to promote higher NGL recoveries at existing processing facilities connected to the system, and to encourage the construction of new cryogenic natural gas processing plants in the region that could be connected to the system. Additionally, we believe that, subject to negotiations with our shippers, the new tariff could result in longer term dedications of NGL supplies to the system and higher fuel reimbursement from our shippers than we have under our existing contracts. Based on current transportation volumes, if the new lower rates are fully implemented, system revenues on Mid-America may decrease by as much as $12 million per year depending upon actual product recoveries and movements. However, it is expected that the lower revenues would be offset by the benefit of longer term dedications, higher fuel recovery and increased volumes. We will periodically review the effectiveness of the new rates to determine if we will elect to keep them in place.

Petrochemical Services. Gross operating margin from this business segment decreased $12.5 million quarter-to-quarter primarily due to an $8.3 million decrease in gross operating margin from our propylene fractionation business resulting from a decrease in product sales margins and propylene transportation volumes caused by a sharp decline in propylene prices during the second quarter of 2005.

Our octane enhancement business experienced an operating loss of $6.1 million during the second quarter of 2005 primarily due to start-up expenses related to isooctane production from our octane-additive production facility. Our isooctane production unit, which was expected to be in service April 1, 2005, began initial production of isooctane and was in production for approximately one month before it was taken out of service for additional modifications to improve its operating rate and product quality. The unit restarted in July and at the end of July 2005 was operating at approximately 90% of capacity and producing an average of 11 MBPD of isooctane. Our octane-additive production facility is capable of producing either MTBE or isooctane and may, in the future, produce MTBE as business conditions warrant. Depending on the outcome of various factors (including pending federal legislation), the facility may be further modified in the future to produce alkylate.

Other. Gross operating margin from this segment pertains to equity earnings we recorded from GulfTerra GP prior to its consolidation with our financial results upon completion of the GulfTerra merger on September 30, 2004.

Six Months Ended June 30, 2005 Compared with the Six Months Ended June 30, 2004

The weighted-average market price for NGLs was 80 cents per gallon for the six months ended June 30, 2005 versus 65 cents per gallon during the same period in 2004—a period-to-period increase of 23%. The Henry Hub market price for natural gas averaged $6.51 per MMBtu for the six months ended June 30, 2005 versus $5.84 per MMBtu during the 2004 period. Polymer grade propylene index prices increased 32% period-to-period and refinery grade propylene index prices increased 31% period-to-period.

Revenues for the six months ended June 30, 2005 increased $1.8 billion over those recorded during the same period in 2004. In general, the trend in consolidated revenues can be attributed to (i) a $882 million increase in revenues from our NGL and petrochemical marketing activities primarily resulting from an increase in overall sales volumes and energy commodity market prices and (ii) the addition of $938 million in revenues from businesses acquired or consolidated since June 30, 2004, which primarily include GulfTerra and the South Texas midstream assets.

Consolidated costs and expenses increased $1.6 billion period-to-period primarily due to (i) an increase in volumes purchased including the effects of higher product prices, which resulted in a $723 million increase in the cost of sales of our NGL and petrochemical marketing activities and (ii) the addition of $692 million in costs and expenses attributable to businesses acquired or consolidated since June 30, 2004. General and administrative costs increased $16.9 million period-to-period primarily due to businesses acquired since June 30, 2004.

Equity earnings from unconsolidated affiliates decreased $17.1 million period-to-period primarily due to the $11.5 million charge recorded in the second quarter of 2005 related to the refinancing of Cameron Highway's project debt. Equity earnings for the first six months of 2005 includes our share of earnings from investments we acquired in connection with the GulfTerra Merger. The first six months of 2004 includes $21.3 million of equity earnings from GulfTerra GP, which we began consolidating on September 30, 2004 as a result of completing the GulfTerra Merger. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to a $136.2 million increase in operating income period-to-period.

The $45.7 million increase in interest expense is attributable to the senior notes we issued during October 2004 in connection with the GulfTerra Merger and the issuance of additional senior notes during the first six months of 2005. Our weighted-average debt principal outstanding was $4.4 billion during the first six months of 2005 compared to $2.1 billion for the same period in 2004.

As a result of the items noted in previous paragraphs, our net income increased $84.2 million to $179.9 million for the six months ended June 30, 2005 from $95.7 million for the 2004 period. The first six months of 2004 includes a $10.8 million benefit related to the cumulative effect of changes in accounting principles adopted during 2004. For additional information regarding the cumulative effect of changes in accounting principles we recorded during 2004, please read "*Other Items*" included within this Item 2.

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

Offshore Pipelines & Services. Gross operating margin from this business segment increased $43.4 million period-to-period primarily due to offshore Gulf of Mexico assets acquired in connection with the GulfTerra Merger. These assets accounted for $40 million of gross operating margin recorded for this segment during the six months ended June 30, 2005. Gross operating margin for the 2005 period also includes $11.5 million in one-time charges related to the refinancing of Cameron Highway's project debt and a $5.1 million one-time benefit related to the resolution of a transportation contract dispute involving Neptune.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment increased $152.5 million period-to-period primarily due to onshore natural gas pipeline and storage assets we acquired in connection with the GulfTerra Merger. These assets accounted for $153.5 million of gross operating margin recorded for this segment for the first six months of 2005. Our Texas Intrastate System generated gross operating margin of $53.5 million during the 2005 period on average transportation volumes of 3,405 BBtus/d. Our San Juan Gathering System contributed $71.9 million of gross operating margin during the 2005 period on average transportation volumes of 1,191 BBtus/d. We acquired the Texas Intrastate System and the San Juan Gathering System in connection with the GulfTerra Merger.

NGL Pipelines & Services. Gross operating margin from this business segment increased $125.5 million period-to-period primarily due to contributions from assets we acquired in connection with the GulfTerra Merger, including the South Texas midstream assets, and improved processing economics. Gross operating margin from natural gas processing assets we have acquired since June 30, 2004 accounted for $89.6 million of the increase in gross operating margin for this segment. Gross operating margin from our NGL marketing activities and Louisiana natural gas processing facilities increased $22 million period-to-period primarily due to higher NGL prices and increased equity NGL production volumes.

Gross operating margin from NGL pipelines and related storage services increased $3 million period-to-period. This business segment benefited from improved gross operating margin attributable to (i) our Mid-America and Seminole pipelines, (ii) our NGL import facility, including related assets, (iii) and additional gross operating margin amounts attributable to our acquisition of additional equity interests in Tri-States. The results of which, were partially offset by lower returns from our NGL storage facilities, South Louisiana pipelines and a $4.3 million charge in May 2005 related to off specification propane injected into our Dixie pipeline.

Gross operating margin from NGL fractionation increased $18.6 million period-to-period primarily due to NGL fractionation assets we acquired in connection with the GulfTerra Merger. Expenses related to support services classified within this segment increased $7.8 million period-to-period primarily due to increased business activities related to acquired assets.

Petrochemical Services. Gross operating margin from this business segment decreased $17.3 million period-to-period primarily due to a $13.1 million decrease in gross operating margin from our octane enhancement business. Our octane-additive production facility encountered isooctane production difficulties during the second quarter of 2005, which resulted in a prolonged period of start-up activities. Also, gross operating margin from our propylene fractionation business decreased $7.6 million period-to-period primarily due to lower product sales margins and propylene transportation volumes caused by a sharp decline in propylene prices during the second quarter of 2005.

Other. Gross operating margin from this segment pertains to equity earnings we recorded from GulfTerra GP prior to its consolidation with our financial results upon completion of the GulfTerra merger on September 30, 2004.

OUR 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. 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, the issuance of additional partnership equity and public or private placement debt. 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.

As noted above, certain of our liquidity and capital resource requirements are fulfilled by borrowings made under debt agreements and/or proceeds from the issuance of additional partnership equity. At June 30, 2005, we had $33 million of unrestricted cash and approximately $540 million of available credit under our Multi-Year Revolving Credit Facility. In total, we had approximately $4.6 billion in principal outstanding under various debt agreements at June 30, 2005.

As a result of our growth objectives, we expect to access debt and equity capital markets from time-to-time and we believe that additional financing arrangements to support our goals 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 "*Our Capital Spending*" included within this Item 2.

Registration Statements and Equity and Debt Offerings

In March 2005, we filed a universal shelf registration statement with the SEC registering the issuance of $4 billion of partnership equity and public debt obligations. In connection with this registration statement, we also registered for resale 35,368,522 common units owned by Shell and 5,631,478 common units owned by a third party, Kayne Anderson MLP Investment Company ("Kayne Anderson"). Kayne Anderson purchased its unregistered common units from Shell in December 2004 and March 2005. We are obligated to register the resale of these common units under a registration rights agreement we executed with Shell in connection with our acquisition of certain of Shell's Gulf Coast midstream energy businesses in September 1999.

In February 2005, we sold 17,250,000 common units (including the over-allotment amount of 2,250,000 common units which closed on March 11, 2005) under a preexisting registration statement from which we received net proceeds of approximately $456.7 million, including Enterprise GP's proportionate net capital contribution of $9.1 million. We used the proceeds from this public offering to repay our 364-Day Acquisition Credit Facility, to temporarily reduce indebtedness outstanding under our Multi-Year Revolving Credit Facility and for general partnership purposes.

In February 2005, our Operating Partnership sold $500 million in principal amount of senior notes in a private offering, comprised of $250 million in principal amount of 10-year senior unsecured notes and $250 million in principal amount of 30-year senior unsecured notes. The 10-year notes ("Senior Notes I") were issued at 99.379% of their principal amount and have annual fixed-rate interest of 5.00% and mature in March 2015. The 30-year notes ("Senior Note J") were issued at 98.691% of their principal amount and have annual fixed-rate interest of 5.75% and a mature in March 2035. The Operating Partnership used the net proceeds from the issuance of Senior Notes I and J to repay $350 million of indebtedness outstanding under Senior Notes A, which was due in March 2005, and the remaining proceeds for general partnership purposes, including the temporary repayment of indebtedness outstanding under the Multi-Year Revolving Credit Facility. An offer to exchange these for registered debt securities began in July 2005 and is currently scheduled to expire in August 2005, unless we decide to extend it.

In June 2005, our Operating Partnership sold $500 million in principal amount of five-year senior unsecured notes. The five-year notes ("Senior Notes K") were issued at 99.834% of their principal amount and have a fixed-rate interest of 4.95% and mature in June 2010. The Operating Partnership used the net proceeds from the issuance of Senior Notes K to temporarily reduce borrowings outstanding under the Multi-Year Revolving Credit Facility and for general partnership purposes, including capital expenditures and business combinations. These notes were registered under the $4 billion universal shelf registration statement we filed with the SEC in March 2005.

Comparison of Cash Flows for the Six Months Ended June 30, 2005
with Cash Flows for the Six Months Ended June 30, 2004

Cash flows from operating activities primarily reflect net income adjusted for depreciation, amortization and similar non-cash amounts; equity earnings and cash distributions from unconsolidated affiliates; and changes in operating accounts. For additional information regarding changes in operating accounts, please read Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Cash flow from operations is primarily based 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, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs and crude oil. In general, we provide services for producers and consumers of natural gas, NGLs and crude oil from the wellhead to the end user. 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. Other risks include fluctuations in oil, natural gas and NGL prices, competitive practices in the midstream energy industry and the impact of operational and systems risks. For a summary of the risk factors pertinent to our business, please read "*Cautionary Statement Regarding Forward-Looking Information and Risk Factors*" included within this Item 2.

Operating activities. For the six months ended June 30, 2005 and 2004, cash provided by operating activities was $117.8 million and $117.1 million, respectively. The period-to-period increase in cash provided by operating activities is partially attributable to increased earnings as discussed under "*Our Results of Operations*," included within this Item 2. A description of the other significant period-to-period fluctuations of the remaining line items within this section of our Unaudited Condensed Statements of Consolidated Cash Flows follows:

- As measured by the net effect of changes in our operating accounts, we used an additional $245.1 million of cash for working capital purposes when compared to the first six months of 2004. In general, the net effect of changes in operating accounts is the result of timing of cash receipts from sales and cash payments for purchases and other expenses near the end of each period. Increases or decreases in inventory are influenced by changes in commodity prices and our marketing activities. A significant component of the net change in operating accounts between the first six months of 2005 and the same period in 2004 relates to our purchase of inventory during the second quarter of 2005 to satisfy forward sales commitments. As a result of positive forward market differentials during the second quarter of 2005, we purchased approximately $111.3 million of volumes that are deliverable under fixed price forward sales contracts. Under the terms of these forward sales contracts, the majority of the volume will be sold during the fourth quarter of 2005.

- Cash distributions from unconsolidated affiliates increased $3.1 million period-to-period primarily due to a $5.1 million distribution we received from Neptune associated with the resolution of a transportation contract dispute, $20.9 million in distributions received from investments we acquired in the GulfTerra Merger, offset by a decrease in distributions of $21.5 million from GulfTerra GP, which we began consolidating on September 30, 2004.

Investing activities. For the six months ended June 30, 2005 and 2004, we used $570.5 million and $84 million, respectively, for investing activities. During the first six months of 2005, we used $74.9 million to purchase from El Paso two entities which owned interests in the Indian Springs natural gas gathering and processing assets, $68.6 million to purchase an additional 46.1% ownership interest in Dixie, $25 million to purchase an additional 2% indirect interest in the Mid-America Pipeline System and an additional 1.6% indirect interest in the Seminole pipeline, and $4.4 million to purchase an additional 41.7% ownership interest in Belle Rose. During the first six months of 2004, we used $45.1 million to purchase additional ownership interests in Tri-States and Seminole. Capital expenditures were $435.8 million during the first six months of 2005 period compared to $28.3 million for the first six months of 2004. For additional information regarding our capital expenditures, please read "*Capital Spending*" included within this Item 2.

Our investments in unconsolidated affiliates were $80.7 million during the first six months of 2005 compared to $0.5 million during the first six months of 2004. In March 2005, we contributed $72 million to Deepwater Gateway to fund our share of the repayment of its $144 million term loan. In addition, our cash flows from investing activities for the six months ended June 30, 2005, include (i) $42.1 million in proceeds from the sale of our 50% equity interest in Starfish in March 2005, which was required to gain regulatory approval for the GulfTerra Merger and (ii) $47.5 million related to a return of our investment in Cameron Highway associated with the refinancing of its project debt in June 2005, which we will use to fund capital expenditures associated with our growth capital projects. For additional information regarding the refinancing of Cameron Highway's debt, please read Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Financing activities. For the six months ended June 30, 2005, cash provided by financing activities was $461.1 million. We used $24.2 million for investing activities during the six months ended June 30, 2004. During the first six months of 2005, we had net borrowings on our debt obligations of $271.3 million compared to net repayments of $362 million during the first six months of 2004. During the first six months of 2005, we 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, including capital expenditures and business combinations. Additionally, we repaid the remaining $242.2 million that was due under our 364-Day Acquisition Credit Facility using proceeds from our February 2005 equity offering. Our repayments of debt during the first six months of 2004 primarily reflect the use of proceeds from our May 2004 equity offering to repay the $225 million Interim Term Loan and to temporarily reduce amounts outstanding under our bank credit facilities. In addition, we also used the $104.5 million in proceeds from our April 2004 settlement of certain interest rate hedging financial instruments to temporarily reduce amounts outstanding under our bank credit facilities.

Cash distributions to partners increased from $181 million during the first six months of 2004 to $346.6 million during the same period in 2005. The increase in cash distributions is primarily due to an increase in the number of units eligible for distributions and an increase in our declared quarterly cash distribution rate. We expect that future cash distributions to partners will increase as a result of our periodic issuance of common units under the DRIP and other equity offerings.

Net proceeds from the issuance of common units were $525.2 million during the first six months of 2005 compared to $411.6 million during the same period in 2004. The first six months of 2005 includes net proceeds of $456.7 million from our February 2005 equity offering of 17,250,000 common units (including the over-allotment amount of 2,250,000 common units which closed on March 11, 2005), and net proceeds of $49.4 million from the sale of 1,926,810 common units in connection with the DRIP, the proceeds of which were primarily used for general partnership purposes. Additionally, during the first six months of 2005 we received proceeds of $19 million from the exercise of unit options related to EPCO's 1998 Long-Term Incentive Plan. The first six months of 2004 includes net proceeds of $353.1 from our May 2004 equity offering of 17,250,000 common units (including the underwriters' over-allotment amount of 2,250,000 common units), and net proceeds of $58.4 million from the sale of 2,811,208 common units in connection with the DRIP.

Our Credit Ratings

Our current credit ratings are Baa3 (investment grade) with a stable outlook as rated by Moody’s Investor Services; BB+ (non-investment grade) with a stable outlook as rated by Standard and Poor’s; and BBB- (investment grade) with a stable outlook by Fitch ratings.

Our Debt Obligations

The following table summarizes our consolidated debt obligations at the dates indicated.

	June 30, 2005	December 31, 2004
Operating Partnership debt obligations:		
364-Day Acquisition Credit Facility, variable rate, repaid in February 2005 (1)		$ 242,229
Multi-Year Revolving Credit Facility, variable rate, due September 2009 (2)	$ 180,000	321,000
Seminole Notes, 6.67% fixed-rate, due December 2005 (3)	15,000	15,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Senior Notes A, 8.25% fixed-rate, repaid March 2005		350,000
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	
Senior Notes J, 5.75% fixed-rate, due March 2035	250,000	
Senior Notes K, 4.95% fixed-rate, due June 2010	500,000	
Dixie revolving credit facility, due June 2007	21,000	
GulfTerra Senior Notes and Senior Subordinated Notes (3,4)	5,673	6,469
Total principal amount	4,575,673	4,288,698
Other, including unamortized discounts and premiums and changes in fair value (5)	7,774	(7,462)
Subtotal long-term debt	4,583,447	4,281,236
Less current maturities of debt (6)	(15,000)	(15,000)
Long-term debt	$ 4,568,447	$ 4,266,236
Standby letters of credit outstanding (7)	$ 97,139	$ 139,052

(1) We used the proceeds from our February 2005 common unit offering to fully repay and terminate the 364-Day Acquisition Credit Facility. For additional information regarding this equity offering, see Note 9.
(2) The Multi-Year Revolving Credit Facility has a $750 million borrowing capacity, which is reduced by the amount of standby letters of credit outstanding.
(3) Solely as it relates to the assets of our GulfTerra, Dixie and Seminole subsidiaries, our senior indebtedness is structurally subordinated and ranks junior in right of payment to the indebtedness of such subsidiaries.
(4) GulfTerra's remaining $0.8 million of 6.25% Senior Notes due June 2010 were called and retired in February 2005.
(5) The June 30, 2005 amount includes $21.2 million related to fair value hedges and $14.6 million in net unamortized discounts.
(6) In accordance with SFAS No. 6, "*Classification of Short-Term Obligations Expected to Be Refinanced*," long-term and current maturities of debt at December 31, 2004 reflected (i) our refinancing of Senior Notes A with proceeds from our Senior Notes I and J in March 2005 and (ii) the repayment of our 364-Day Acquisition Credit Facility using proceeds from an equity offering completed in February 2005.
(7) Of the $97 million in standby letters of credit outstanding at June 30, 2005, $67 million is associated with a letter of credit facility we entered into in November 2004 in connection with our Independence Hub capital project, and the remaining amounts were issued under our Multi-Year Revolving Credit Facility. At December 31, 2004, $115 million of the $139 million of standby letters of credit outstanding was associated with the Independence Hub letter of credit facility. The decrease in standby letters of credit outstanding since December 31, 2004 under our Independence Hub letter of credit facility is the result of construction payments made by Independence Hub.

We have three unconsolidated affiliates with long-term debt obligations. The following table shows our ownership interest in each entity at June 30, 2005 and total long-term debt obligations (including current maturities) of each unconsolidated affiliate at June 30, 2005, on a 100% basis to the joint venture.

	Our Ownership Interest	Total
Cameron Highway	50.0%	$ 415,000
Poseidon	36.0%	102,000
Evangeline	49.5%	35,650
Total		$ 552,650

For additional 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.

OUR CONTRACTUAL OBLIGATIONS

With regards to our material contractual obligations, there have been no significant changes outside of the ordinary course of business since those reported in our annual report on Form 10-K for the year ended December 31, 2004 with the exception of debt. For additional information regarding changes in our consolidated debt obligations since December 31, 2004, please read Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

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:

- SFAS No. 123(R) "*Share-Based Payment*" issued by the FASB and the related SAB 107 issued by the SEC;
- FIN 46(R)-5 "*Implicit Variable Interests Under FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities*";
- FIN 47 "*Accounting for Conditional Asset Retirement Obligations*"; and
- SFAS No. 154 "*Accounting Changes and Error Corrections*."

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.

OUR CRITICAL ACCOUNTING PRINCIPLES

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, 2004. For a detailed discussion of these policies, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Our Critical Accounting Policies" in our annual report on Form 10-K for 2004. 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 incorporates our assumptions regarding the useful economic lives and residual values of such 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 June 30, 2005 and December 31, 2004, the net book value of our property, plant and equipment was $8.2 billion and $7.8 billion, respectively. For additional information regarding our property, plant and equipment, please read Note 5 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 loss in value of the investment that is an other than 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 the asset or asset group; and salvage values. A significant change in these underlying assumptions could result in our recording an impairment charge. We did not record any impairment charges during the six months ended June 30, 2005 and 2004.

In light of a proposed third-party transaction related to potential changes in investee ownership interests in Neptune during the second half of 2005, we are evaluating our operations with respect to this investment and our level of ownership interests in such asset. At June 30, 2005, the carrying value of our 25.67% ownership interest in Neptune, an equity method investment, was $69.8 million.

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 June 30, 2005 and December 31, 2004, the carrying value of our intangible asset portfolio was $957 million and $980.6 million. For additional information regarding our intangible assets, please read Note 7 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. In general, goodwill is attributable to the excess of the purchase price over the fair value of assets acquired. Goodwill is not amortized. Instead, goodwill is tested for impairment at a reporting unit level 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. Testing goodwill for impairment involves calculating the fair value of a reporting unit, which in turn is based 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 June 30, 2005 and December 31, 2004, the carrying value of our goodwill was $483.4 million and $459.2 million. For additional information regarding our goodwill, please read Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Our use of estimates for revenues and expenses. Our use of estimates for revenues, as well as our use of estimates for operating costs and other expenses has increased as a result of SEC regulations that require us to submit financial information on increasingly 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 incorrect, it could result in material adjustments to our results of operations between periods.

At June 30, 2005, we had approximately $25 million in receivables for the estimated recovery of expenditures resulting from damage to certain offshore operations due to the effects of Hurricane Ivan, a Category 3 hurricane which struck the U.S. Gulf Coast in September 2004.

Reserves for environmental matters. Each of our business segments is subject to extensive federal, state and local laws and regulations governing environmental quality and pollution control. 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. Our actual results may differ from our estimates, and our estimates can be, and often are, revised in the future, either negatively or positively, depending upon the outcome or expectations based on the facts surrounding each exposure.

At June 30, 2005 and December 31, 2004, we had a liability for environmental remediation of $21 million, which was derived from a range of reasonable estimates based upon studies and site surveys. In accordance with SFAS No. 5 "*Accounting for Contingencies*" and FASB Interpretation No. 14, "*Reasonable Estimation of the Amount of a Loss*," we recorded our best estimate of the costs for these remediation activities.

Natural gas imbalances. Natural gas imbalances result when customers physically deliver a larger or smaller quantity of gas into our pipelines than they take out. We generally value our imbalances using a twelve-month moving average of natural gas prices, which we believe is an appropriate assumption to estimate the value of the imbalances at the time of settlement given that the actual settlement dates are generally not known. Changes in natural gas prices may impact our estimates.

At June 30, 2005 and December 31, 2004, our imbalance receivables were $44.8 million and $56.7 million, respectively, and are reflected as a component of accounts receivable. At June 30, 2005 and December 31, 2004, our imbalance payables were $37.6 million and $59 million, respectively, and are reflected as a component of accrued gas payables.

SUMMARY OF RELATED PARTY TRANSACTIONS

The following is a summary of our related party relationships and transactions. For additional information regarding our current and historical related party relationships, please read Note 8 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Relationship with EPCO. We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a non-voting director and Chairman of Enterprise GP, our general partner. In addition, the executive and other officers of Enterprise GP are employees of EPCO, including Robert G. Phillips who is President and Chief Executive Officer (“CEO”) and a director of Enterprise GP. The principal business activity of Enterprise GP is to act as our managing partner.

Collectively, EPCO and its affiliates owned a 38.6% equity interest in Enterprise at June 30, 2005, which includes their ownership interest in Enterprise GP.

We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the Administrative Services Agreement. 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. Additionally, we reimburse EPCO for the costs associated with the office space we occupy related to our partnership's headquarters. Our other transactions with EPCO and its affiliates include:

- 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.
- In the normal course of business, we buy from and sell certain NGL products to an affiliate of EPCO.

We and Enterprise GP are both separate legal entities from EPCO and its other affiliates, with assets and liabilities that are separate from EPCO and its other affiliates. EPCO depends on cash distributions it receives as an equity owner in us to fund most of its other operations and to meet its debt obligations. For the six months ended June 30, 2005 and 2004, EPCO affiliates received $95.2 million and $85.6 million in distributions from us, respectively. The ownership interests in us and our general partner that are owned or controlled by EPCO and its affiliates, other than Dan Duncan LLC and trusts affiliated with Dan L. Duncan, are pledged as security under an

EPCO credit facility. In the event of a default under such credit facility, a change in control of us or our general partner could occur.

Our related party revenues from EPCO and affiliates were $2 thousand and $0.1 million for the three months ended June 30, 2005 and 2004, and $0.3 million and $2.2 million for the six months ended June 30, 2005 and 2004, respectively. Our related party expenses paid to EPCO and affiliates were $67.8 million and $45.3 million for the three months ended June 30, 2005 and 2004, and $134.1 million and $91.3 million for the six months ended June 30, 2005 and 2004, respectively.

Relationship with TEPPCO. On February 24, 2005, an affiliate of EPCO acquired Texas Eastern Products Pipeline Company, LLC ("TEPPCO GP"), the general partner of TEPPCO Partners, L.P. (“TEPPCO”), and 2,500,000 common units of TEPPCO from Duke Energy Field Services, LLC ("Duke Energy") for approximately $1.2 billion in cash. TEPPCO GP owns a 2% general partner interest in TEPPCO and is the managing partner of TEPPCO and its subsidiaries. Subsequently, EPCO reconstituted the board of directors of TEPPCO GP and Dr. Ralph Cunningham (a former independent director of Enterprise GP) was named Chairman of TEPPCO GP. Due to EPCO's actions to reconstitute the board of directors of TEPPCO GP and TEPPCO GP's ability to direct the management of TEPPCO, TEPPCO GP and TEPPCO became related parties to EPCO and the Company during the first quarter of 2005. The employees of TEPPCO became EPCO employees on June 1, 2005. Our significant related party transactions with TEPPCO consist of the purchase of NGL pipeline transportation and storage services.

On March 11, 2005, the Bureau of Competition of the U.S. Federal Trade Commission (“FTC”) delivered written notice to EPCO’s legal advisor that it was conducting a non-public investigation to determine whether EPCO’s acquisition of TEPPCO GP may tend substantially to lessen competition. No filings were required under the Hart-Scott-Rodino Act in connection with EPCO’s purchase of TEPPCO GP. EPCO and its affiliates, including us, may receive similar inquiries from other regulatory authorities and intend to cooperate fully with any such investigations and inquiries. In response to such FTC investigation or any inquiries EPCO and its affiliates may receive from other regulatory authorities, we may be required to divest certain assets. In the event we are required to divest significant assets, our financial condition could be affected.

We did not have any related party revenues from TEPPCO and affiliates for the three and six months ended June 30, 2005. Our related party expenses paid to TEPPCO and affiliates were $7.1 million and $8.6 million for the three and six months ended June 30, 2005, respectively.

Relationship with unconsolidated affiliates. Our significant related party transactions with unconsolidated affiliates consist of the sale of natural gas to Evangeline, purchase of pipeline transportation services from Dixie (prior to its consolidation with our results beginning in February 2005, see Note 3) 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. Our related party revenues from unconsolidated affiliates were $80.9 million and $57.8 million for the three months ended June 30, 2005 and 2004, and $138.9 million and $106.9 million for the six months ended June 30, 2005 and 2004. Our related party expenses paid to unconsolidated affiliates were $3.9 million and $6.9 million for the three months ended June 30, 2005 and 2004, and $10.5 million and $16.5 million for the six months ended June 30, 2005 and 2004, respectively.

Historical relationship with Shell. Historically, Shell Oil Company, its subsidiaries and affiliates (“Shell”) were collectively considered a related party because Shell owned more than 10% of our limited partner interests and, prior to September 2003, Shell owned a 30% ownership interest in Enterprise GP. As a result of Shell selling a portion of its limited partner interests in us to third parties in December 2004 and during the first seven months of 2005, Shell now owns less than 10% of our common units. Shell sold its 30% interest in Enterprise GP to an affiliate of EPCO in September 2003. As a result of Shell's reduced equity interest in us and its lack of control of Enterprise, Shell ceased to be considered a related party beginning in the first quarter of 2005. For the three months ended June 30, 2004, our related party revenues from Shell and expenses paid to Shell were $144.9 million and $180 million, respectively. Our related party revenues from Shell and expenses paid to Shell for the six months ended June 30, 2004, were $249 million and $346.8 million, respectively.

OTHER ITEMS

Recent regulatory developments. On May 4, 2005, the FERC issued a policy statement providing that all entities owning public utility assets – oil and gas pipelines and electric utilities – would be permitted to include an income tax allowance in their rates to reflect the actual or potential income tax liability attributable to their public utility income, regardless of the form of ownership. Any tax pass-through entity seeking an income tax allowance would have to establish that its partners or members have an actual or potential income tax obligation on the entity's public utility income. The FERC has stated that it will determine on a case-by-case basis whether there is an actual or potential income tax liability. The policy appears to provide an opportunity for partnership-owned pipelines to seek allowances based upon their entire income paid to partners, rather than the partial allowance which was limited to partner interests owned by corporate partners. The policy statement is subject to rehearing and clarification by the FERC. We have not yet been able to determine the effect, if any, that this new FERC policy statement will have on the rates for transportation services on our interstate pipelines we charge or on the rates we will be allowed to charge in the future. We expect the implementation of the policy in individual cases will be subject to review by the United States Court of Appeals.

In December 2002, High Island Offshore System ("HIOS'), an interstate natural gas pipeline owned by us, filed a rate case pursuant to Section 4 of the Natural Gas Act before the FERC to increase its transportation fees. The FERC accepted HIOS' tariff sheets implementing the new rates, subject to refund, and set certain issues for hearing before an Administrative Law Judge ("ALJ"). The ALJ issued an initial decision on the issues, proposing rates lower than the rate initially proposed by HIOS. In August 2004, in response to the ALJ's initial decision, HIOS filed a settlement agreement whereby HIOS proposed to implement its rates in effect prior to this proceeding for a prospective three-year period. In January 2005, the FERC issued an order rejecting HIOS' settlement offer and generally affirming the ALJ's initial decision, resulting in rates significantly lower than the rate proposed in HIOS' settlement offer. In February 2005, HIOS filed a request for rehearing with the FERC. In July 2005, the FERC issued an order denying all requests for rehearing, and the FERC required HIOS to implement the approved rate and to make refunds to its customers. The refunds to HIOS' customers are due in August 2005, and HIOS is fully reserved for the refund obligations.

Pipeline integrity costs. Our NGL, petrochemical and natural gas pipelines are subject to pipeline integrity management programs administered by the U.S. Department of Transportation, through its Office of Pipeline Safety. During the three months ended June 30, 2005, we spent approximately $4.2 million to comply with these programs, of which $2.8 million was recorded as an operating expense with the remaining $1.4 million being capitalized. We spent approximately $10.5 million to comply with these programs during the six months ended June 30, 2005, of which $7.1 million was recorded as an operating expense with the remaining $3.4 million being capitalized. Our net cash outlay for the pipeline integrity program is estimated to be approximately $42.9 million for the remainder of 2005. The forecasted cost for 2005 is net of the value of an indemnification for such expenses that we expect to receive from El Paso related to pipelines acquired from GulfTerra.

Non-GAAP reconciliation. A reconciliation of our measurement of total non-GAAP gross operating margin to GAAP operating income and income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles (as shown on our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income included under Item 1 of this quarterly report on Form 10-Q) follows:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2005	2004	2005	2004
Total non-GAAP gross operating margin	$ 245,875	$ 107,102	$ 521,089	$ 238,243
Adjustments to reconcile total non-GAAP gross operating margin to GAAP operating income:				
Depreciation and amortization in operating costs and expenses	(101,048)	(31,715)	(201,013)	(62,235)
Retained lease expense, net in operating costs and expenses	(528)	(2,273)	(1,056)	(4,547)
Gain (loss) on sale of assets in operating costs and expenses	(83)	(17)	5,353	(115)
General and administrative costs	(18,710)	(7,087)	(33,403)	(16,553)
GAAP consolidated operating income	125,506	66,010	290,970	154,793
Other expense	(55,501)	(31,699)	(107,995)	(64,156)
GAAP income before provision for income taxes, minority interest and cumulative effect of changes in accounting principles	$ 70,005	$ 34,311	$ 182,975	$ 90,637

EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railcars for $1 per year. These subleases (the “retained lease expense” in the previous table) are part of the Administrative Services Agreement that we executed with EPCO in connection with our formation in 1998. EPCO holds these items pursuant to operating leases for which it has retained the corresponding cash lease payment obligation.

Operating costs and expenses (as shown on the Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income included under Item 1 of this quarterly report on Form 10-Q) classify the lease payments being made by EPCO as a non-cash related party operating expense, with the offset to partners’ equity on the Unaudited Condensed Consolidated Balance Sheets recorded as a general contribution to us. Apart from the partnership interests we granted to EPCO at our formation, EPCO does not receive any additional ownership rights as a result of its contribution to us of the retained leases.

Cumulative effect of accounting changes recorded during 2004. The $10.8 million cumulative effect of changes in accounting principles represents the combined impact of changing (i) the method our BEF subsidiary uses to account for its planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred method and (ii) the method we used to account for our investment in VESCO.

Certain reclassifications have been made to the prior year’s financial statements to conform to the current year presentation. In accordance with SFAS No. 3, “*Reporting Accounting Changes in Interim Financial Statements*,” we have reclassified amounts related to our adoption of EITF 03-16, “*Accounting for Investments in Limited Liability Companies*,” on July 1, 2004. Our adoption of EITF 03-16 on that date required us to change our method of accounting for our 13.1% investment in VESCO to the equity method from the cost method. Since this change in accounting principle was made during the third quarter of 2004, our statement of consolidated operations and statement of consolidated cash flows for the first and second quarters of 2004 has been recast for comparability purposes.

Changes in directors of Enterprise GP. On March 22, 2005, Dr. Ralph S. Cunningham and Lee W. Marshall, Sr. resigned from the Board of Directors of our general partner, Enterprise GP. William Barnett was appointed as a new director of Enterprise GP on March 22, 2005.

The Board of Directors of Enterprise GP (the "Board") has determined that Mr. Barnett meets the director independence requirements under the applicable rules and regulations of the SEC and under the NYSE's Audit Committee Additional Requirements. Mr. Barnett serves as a member of the Board's Audit and Conflicts Committee. Mr. Barnett also serves as the Chairman of the Board's Governance Committee.

Effective July 1, 2005, O.S. Andras retired as Vice Chairman of the Board of Directors of Enterprise GP, but will continue to serve as a non-executive director.

Following the above changes, the directors of Enterprise GP are Dan L. Duncan, Chairman; Robert G. Phillips, Chief Executive Officer and President; O.S. Andras; W. Matt Ralls; Richard S. Snell, and Mr. Barnett. To continue the voting majority of independent directors, Enterprise GP expects to appoint a fourth independent director to its board by the end of the third quarter of 2005. Until such time that a fourth independent director is elected, Mr. Duncan will be a non-voting director and in order to preserve the voting majority of the independent directors.

Mr. Ralls, who has served as a member of the Audit and Conflicts Committee, became Chairman of that committee and continues to serve as a member of the Governance Committee, of which he was previously the Chairman. Mr. Snell became a member of the Audit and Conflicts Committee and continues to serve on the Governance Committee.

For additional information regarding Mr. Barnett and this change in directors of Enterprise GP, please read our Current Report on Form 8-K filed on March 23, 2005.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION AND RISK FACTORS

This quarterly report contains various forward-looking statements and information that are based on our beliefs and those of Enterprise 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 reflected in such forward-looking statements are reasonable, neither we nor Enterprise GP can give any assurances 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 our summarized "*Risk Factors*" below.

Risk Factors. An investment in our common units involves risks. If any of these risks were to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our common units could decline, and you could lose all or part of your investment. Among the key risk factors that may have a direct impact on our results of operations and financial condition are:

- fluctuations in oil, natural gas and NGL prices and production due to weather and other natural and economic forces;
- the effects of the combined company's debt level on its future financial and operating flexibility;
- a reduction in demand for our products by the petrochemical, refining or heating industries;
- a decline in the volumes of NGLs delivered by our facilities;
- the failure of our credit risk management efforts to adequately protect against customer non-payment;
- terrorist attacks aimed at our facilities; and
- the failure to successfully integrate our operations with any companies we acquire.

Enterprise has no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise. For additional information regarding our risk factors, please refer to the section titled "*Risk Factors*" included under Item 7 of our 2004 annual report on Form 10-K (Commission File No. 1-14323). Other risks involved in our business are discussed under "*Quantitative and Qualitative Disclosures about Market Risk*" included under Item 3 of this quarterly report on Form 10-Q.

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 the variability of future earnings, fair values of certain debt instruments and cash flows resulting from changes in applicable 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 rate borrowings under 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.

As summarized in the following table, we had nine interest rate swap agreements outstanding at June 30, 2005 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 6.3%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 4.85%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.6% to 4.36%	$600 million

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

The total fair value of these nine interest rate swaps at June 30, 2005 and December 31, 2004, was an asset of $21.2 million and $0.5 million, respectively, with an offsetting increase in the fair value of the underlying debt. Interest expense for the three months ended June 30, 2005 and 2004 reflects a benefit of $2.9 million and $2 million, respectively, from interest rate swap agreements. For the six months ended June 30, 2005 and 2004, interest expense reflects a benefit of $7.5 million and $3.7 million, respectively, from interest rate swap agreements.

The following table shows the effect of hypothetical changes in interest rates on the estimated fair value ("FV") of our interest rate swap portfolio and the related change in fair value of the underlying debt at July 13, 2005 (dollars in thousands). Income is not affected by changes in the fair value of these swaps; however, these swaps effectively convert the hedged portion of fixed-rate debt to variable-rate debt. As a result, interest expense (and related cash outlays for debt service) will increase or decrease with the change in the periodic "reset" rate associated with the respective swap. Typically, the reset rate is an agreed upon index rate published for the first day of the six-month interest calculation period.

Scenario	Resulting Classification	Swap FV at July 13, 2005	Change in FV of Debt Increase (Decrease)
FV assuming no change in underlying interest rates	*Asset (Liability)*	$ 5,729	
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	(22,320)	$ (28,049)
FV assuming 10% decrease in underlying interest rates	*Asset (Liability)*	33,779	28,049

In August 2005, we entered into two additional interest rate swap agreements with an aggregate notional amount of $200 million in which we exchanged the payment of fixed rate interest on a portion of the principal outstanding under Senior Notes K for variable rate interest. We have designated these two interest rate swaps as fair value hedges under SFAS No. 133 since they mitigate changes in the fair value of the underlying fixed rate debt. Under each swap agreement, we will pay the counterparty a variable interest rate based on six-month LIBOR rates (plus an applicable margin as defined in each swap agreement) and receive back from the counterparty a fixed interest rate payment of 4.95%, which is the stated interest rate of Senior Notes K. We will settle amounts receivable from or payable to the counterparty every six months (the "settlement period"), with the first settlement occurring on December 1, 2005. The settlement amount will be amortized ratably to earnings as either an increase or a decrease in interest expense over the settlement period.

During 2004, we entered into two groups of four forward-starting interest rate swap transactions having an aggregate notional amount of $2 billion each in anticipation of our financing activities associated with the closing of the GulfTerra Merger. These interest rate swaps were accounted for as cash flow hedges and were settled during 2004 at a net gain to us of $19.4 million, which will be reclassified from accumulated other comprehensive income to reduce interest expense over the life of the associated debt.

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 natural gas and NGLs, 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 or NGLs.

At June 30, 2005 and December 31, 2004, we had a limited number of commodity financial instruments in our portfolio, which primarily consisted of natural gas cash flow and fair value hedges. The fair value of our commodity financial instrument portfolio at June 30, 2005 and December 31, 2004 was a liability of $14 thousand and an asset of $0.2 million, respectively. Excluding the reclassification of a $1.4 million gain from accumulated other comprehensive income during the first quarter of 2005 (see discussion below regarding the effect of financial instruments on accumulated other comprehensive income), we recorded nominal amounts of earnings from our commodity financial instruments during the three and six months ended June 30, 2005 and 2004.

We assess the risk of our commodity financial instrument portfolio using a sensitivity analysis model. The sensitivity analysis applied to this portfolio measures the potential income or loss (i.e., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at the date indicated within the following table. The following table shows the effect of hypothetical price movements on the estimated fair value (“FV”) of this portfolio at July 13, 2005 (dollars in thousands):

Scenario	Resulting Classification	Commodity Financial Instr. Portfolio FV
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (2)
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(2)
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	(2)

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, 2004.

		Interest Rate Fin. Instrs.		
	Commodity Financial Instruments	Treasury Locks	Forward-Starting Interest Rate Swaps	Accumulated Other Comprehensive Income Balance
Balance, December 31, 2004	$ 1,434	$ 4,572	$ 18,548	$ 24,554
Change in fair value of commodity financial instrument	(1,434)			(1,434)
Reclassification of gain on settlement of treasury locks to interest expense		(219)		(219)
Reclassification of gain on settlement of forward-starting swaps to interest expense			(1,782)	(1,782)
Balance, June 30, 2005	$ -	$ 4,353	$ 16,766	$ 21,119

During the remainder of 2005, we will reclassify a combined $2 million from accumulated other comprehensive income as a reduction in interest expense from our treasury locks and forward-starting interest rate swaps. In addition, we reclassified an approximate $1.4 million gain into income from accumulated other comprehensive income related to a commodity cash flow hedge acquired in the GulfTerra Merger. This gain is primarily due to an increase in fair value from that recorded for the commodity cash flow hedge at September 30, 2004.

ITEM 4. CONTROLS AND PROCEDURES.

Our management, with the participation of the CEO and 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, including internal controls over financial reporting, 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.

Other than the events discussed under "*Merger with GulfTerra and Related Transactions and Dixie Pipeline Company*" below, 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.

Merger with GulfTerra and Related Transactions and Dixie Pipeline Company. As presented under Section 9A "Controls and Procedures" of our 2004 annual report on Form 10-K, we completed the GulfTerra Merger and the acquisition of certain South Texas midstream assets from El Paso on September 30, 2004, which on a combined basis met the criteria of being a material acquisition for us. On June 22, 2004, the Office of the Chief Accountant of the SEC issued guidance regarding the reporting of internal controls over financial reporting in connection with a major acquisition. On October 6, 2004, the SEC revised its guidance to include expectations of quarterly reporting updates of new internal controls and the status of the controls regarding any exempted businesses. On October 18, 2004, the Disclosure Committee of Enterprise GP met and voted to recommend the exclusion of GulfTerra and the South Texas midstream assets from the scope of Enterprise's Sarbanes-Oxley Section 404 Annual Report on Internal Control Over Financial Reporting as of December 31, 2004. A summary of the reasons for this exclusion is found under Section 9A of our 2004 annual report on Form 10-K.

In February 2005, we purchased a 26% ownership interest in Dixie Pipeline Company ("Dixie"). As a result, Dixie became a consolidated subsidiary of Enterprise and our Unaudited Condensed Statement of Consolidated Operations for the six months ended June 30, 2005 includes four months of consolidated results from Dixie. Prior to our purchase of such interest, we accounted for our investment in Dixie using the equity method. Our management, with the participation of the Disclosure Committee of Enterprise GP, has evaluated the effectiveness of Dixie's disclosure controls and procedures as of June 30, 2005. Based on this evaluation, the CEO and CFO of our general partner have concluded that Dixie's disclosure controls and procedures are effective to ensure that material information relating to Dixie's financial condition and results of operations is made known to us on a timely basis.

PART II. OTHER INFORMATION.

ITEM 1. LEGAL PROCEEDINGS.

See Part I, Item 1, Financial Statements, Note 16, "*Litigation*," which is incorporated herein by reference.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS.

We did not repurchase any of our common units during the three and six months ended June 30, 2005. As of June 30, 2005, we and our affiliates are authorized to repurchase up to 618,400 common units under the December 1998 common unit repurchase program. Common units repurchased under this publicly announced program were classified as treasury units prior to their permanent retirement during the second quarter of 2005. Future purchases may be held as treasury units.

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 No.	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 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	Fourth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of October 1, 2004 (incorporated by reference to Exhibit 3.1 to Form 8-K filed October 6, 2004).
3.2	Second Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, among Duncan Family Interests, Inc., Dan Duncan LLC, and GulfTerra GP Holding Company dated September 30, 2004 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 30, 2004).
3.3	Application for Admission by Enterprise GP Holdings L.P. as a Substituted Member of Enterprise Products GP, LLC (incorporated by reference to Exhibit 3.1 to Form 8-K filed January 18, 2005).
3.4	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).
3.5	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 filed December 27, 2004).
3.6	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 filed December 27, 2004).
4.1	Indenture dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.2	First Supplemental Indenture dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.3	Global Note representing $350 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	Second Supplemental Indenture dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.5	Global Note representing $500 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 10-K filed March 31, 2003).
4.6	Global Notes representing $450 million principal amount of 7.50% Senior Notes due 2011

	(incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.7	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-1/A; File No. 333-52537, filed July 21, 1998).
4.8	Contribution Agreement dated September 17, 1999 (incorporated by reference to Exhibit "B" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.9	Registration Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "E" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.10	Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "C" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.11	Amendment No. 1, dated September 12, 2003, to Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit 4.1 to Form 8-K filed September 15, 2003).
4.12	Agreement dated as of March 4, 2004 among Enterprise Products Partners L.P., Shell US Gas & Power LLC and Kayne Anderson MLP Investment Company (incorporated by reference to Exhibit 4.31 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2004).
4.13	$750 Million Multi-Year Revolving Credit Agreement dated as of August 25, 2004, among Enterprise Products Operating L.P., the Lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, Citibank, N.A. and JPMorgan Chase Bank, as Co-Syndication Agents, Mizuho Corporate Bank, Ltd., SunTrust Bank and The Bank of Nova Scotia, as Co-Documentation Agents, Wachovia Capital Markets, LLC, Citigroup Global Markets Inc. and JPMorgan Chase Securities, Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 4.1 to Form 8-K filed on August 30, 2004).
4.14	Guaranty Agreement dated as of August 25, 2004, by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent for the several lenders that are or become parties to the Credit Agreement included as Exhibit 4.1, above (incorporated by reference to Exhibit 4.2 to Form 8-K filed on August 30, 2004).
4.15	$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).
4.16	Guaranty Agreement dated as of August 25, 2004, by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent for the several lenders that are or become parties to the Credit Agreement included as Exhibit 4.3, above (incorporated by reference to Exhibit 4.4 to Form 8-K filed on August 30, 2004).
4.17	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).
4.18	First Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on October 6, 2004).
4.19	Second Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on October 6, 2004).
4.20	Third Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed on October 6, 2004).
4.21	Fourth Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed on October 6, 2004).
4.22	Global Note representing $500 million principal amount of 4.000% Series B Senior Notes due

	2007 with attached Guarantee (incorporated by reference to Exhibit 4.14 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2004).
4.23	Global Note representing $500 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2004).
4.24	Global Note representing $150 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2004).
4.25	Global Note representing $350 million principal amount of 6.650% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2004).
4.26	Global Note representing $500 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.27 to Form 10-K for the year ended December 31, 2004 filed on March 15, 2005).
4.27	Registration Rights Agreement dated as of October 4, 2004, among Enterprise Products Operating L.P., Enterprise Products Partners L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.17 to Form 8-K filed on October 6, 2004).
4.28	Fifth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on March 3, 2005).
4.29	Sixth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on March 3, 2005).
4.30	Rule 144A Global Note representing $250,000,000 principal amount of 5.00% Series A Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed on March 3, 2005).
4.31	Rule 144A Note representing $250,000,000 principal amount of 5.75% Series A Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed on March 3, 2005).
4.32	Registration Rights Agreement dated as of March 2, 2005, among Enterprise Products Partners, L.P., Enterprise Products Operating L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.6 to Form 8-K filed on March 3, 2005).
4.33	Assumption Agreement dated as of September 30, 2004 between Enterprise Products Partners L.P. and GulfTerra Energy Partners, L.P. relating to the assumption by Enterprise of GulfTerra's obligations under the GulfTerra Series F2 Convertible Units (incorporated by reference to Exhibit 4.4 to Form 8-K/A-1 filed on October 5, 2004).
4.34	Statement of Rights, Privileges and Limitations of Series F Convertible Units, included as Annex A to Third Amendment to the Second Amended and Restated Agreement of Limited Partnership of GulfTerra Energy Partners, L.P., dated May 16, 2003 (incorporated by reference to Exhibit 3.B.3 to Current Report on Form 8-K of GulfTerra Energy Partners, L.P., file no. 001-11680, filed with the Commission on May 19, 2003).
4.35	Unitholder Agreement between GulfTerra Energy Partners, L.P. and Fletcher International, Inc. dated May 16, 2003 (incorporated by reference to Exhibit 4.L to Current Report on Form 8-K of GulfTerra Energy Partners, L.P., file no. 001-11680, filed with the Commission on May 19, 2003).
4.36	Indenture dated as of May 17, 2001 among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and the Chase Manhattan Bank, as Trustee (filed as Exhibit 4.1 to GulfTerra’s Registration Statement on Form S-4 filed June 25, 2001, Registration Nos. 333-63800 through 333-63800-20); First Supplemental Indenture dated as of April 18, 2002 (filed as Exhibit 4.E.1 to GulfTerra’s 2002 First Quarter Form 10-Q); Second Supplemental Indenture dated as of April 18, 2002 (filed as Exhibit 4.E.2 to GulfTerra’s 2002 First Quarter Form 10-Q); Third Supplemental Indenture dated as of October 10, 2002 (filed as Exhibit 4.E.3 to GulfTerra’s 2002 Third Quarter Form 10-Q); Fourth Supplemental Indenture dated as of November 27, 2002 (filed as Exhibit 4.E.1 to GulfTerra’s Current Report on Form 8-K dated March 19, 2003); Fifth Supplemental Indenture dated as of January 1, 2003 (filed as Exhibit 4.E.2

	to GulfTerra's Current Report on Form 8-K dated March 19, 2003); Sixth Supplemental Indenture dated as of June 20, 2003 (filed as Exhibit 4.E.1 to GulfTerra's 2003 Second Quarter Form 10-Q, file no. 001-11680).
4.37	Seventh Supplemental Indenture dated as of August 17, 2004 (filed as Exhibit 4.E.1 to GulfTerra's Current Report on Form 8-K filed on August 19, 2004, file no. 001-11680).
4.38	Indenture dated as of November 27, 2002 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee (filed as Exhibit 4.1 to GulfTerra's Current Report of Form 8-K dated December 11, 2002); First Supplemental Indenture dated as of January 1, 2003 (filed as Exhibit 4.1.1 to GulfTerra's Current Report on Form 8-K dated March 19, 2003); Second Supplemental Indenture dated as of June 20, 2003 (filed as Exhibit 4.1.1 to GulfTerra's 2003 Second Quarter Form 10-Q, file no. 001-11680).
4.39	Third Supplemental Indenture dated as of August 17, 2004 (filed as Exhibit 4.1.1 to GulfTerra's Current Report on Form 8-K filed on August 19, 2004, file no. 001-11680).
4.40	Indenture dated as of March 24, 2003 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee dated as of March 24, 2003 (filed as Exhibit 4.K to GulfTerra's Quarterly Report on Form 10-Q dated May 15, 2003); First Supplemental Indenture dated as of June 30, 2003 (filed as Exhibit 4.K.1 to GulfTerra's 2003 Second Quarter Form 10-Q, file no. 001-11680).
4.41	Second Supplemental Indenture dated as of August 17, 2004 (filed as Exhibit 4.K.1 to GulfTerra's Current Report on Form 8-K filed on August 19, 2004, file no. 001-11680).
4.42	Indenture dated as of July 3, 2003, by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (Filed as Exhibit 4.L to GulfTerra's 2003 Second Quarter Form 10-Q, file no. 001-11680).
4.43	First Supplemental Indenture dated as of August 17, 2004 (filed as Exhibit 4.K.1 to GulfTerra's Current Report on Form 8-K filed on August 19, 2004, file no. 001-11680).
4.44	Amended and Restated Credit Agreement dated as of June 29, 2005, among Cameron Highway Oil Pipeline Company, the Lenders party thereto, and SunTrust Bank, as Administrative Agent and Collateral Agent (incorporated by reference to Exhibit 4.1 to Form 8-K filed on July 1, 2005).
10.1	Transportation Contract between Enterprise Products Operating L.P. and Enterprise Transportation Company dated June 1, 1998 (incorporated by reference to Exhibit 10.3 to Registration Statement Form S-1/A filed July 8, 1998).
10.2	Partnership Agreement among Sun BEF, Inc., Liquid Energy Fuels Corporation and Enterprise Products Company dated May 1, 1992 (incorporated by reference to Exhibit 10.5 to Registration Statement on Form S-1 filed May 13, 1998).
10.3	Propylene Facility and Pipeline Agreement between Enterprise Petrochemical Company and Hercules Incorporated dated December 13, 1978 (incorporated by reference to Exhibit 10.9 to Registration Statement on Form S-l filed May 13, 1998).
10.4	Restated Operating Agreement for the Mont Belvieu Fractionation Facilities Chambers County, Texas among Enterprise Products Company, Texaco Producing Inc., El Paso Hydrocarbons Company and Champlin Petroleum Company dated July 17, 1985 (incorporated by reference to Exhibit 10.10 to Registration Statement on Form S-l/A filed July 8, 1998).
10.5	Amendment to Propylene Facility and Pipeline Agreement and Propylene Sales Agreement between HIMONT U.S.A., Inc. and Enterprise Products Company dated January 1, 1993 (incorporated by reference to Exhibit 10.12 to Registration Statement on Form S-l/A filed July 8, 1998).
10.6	Amendment to Propylene Facility and Pipeline Agreement and Propylene Sales Agreement between HIMONT U.S.A., Inc. and Enterprise Products Company dated January 1, 1995 (incorporated by reference to Exhibit 10.13 to Registration Statement on Form S-l/A filed July 8, 1998).
10.7	Seventh Amendment to Conveyance of Gas Processing Rights, dated as of April 1, 2004 among Enterprise Gas Processing, LLC, Shell Oil Company, Shell Exploration & Production Company, Shell Offshore Inc., Shell Consolidated Energy Resources Inc., Shell Land & Energy Company, Shell Frontier Oil & Gas Inc. and Shell Gulf of Mexico Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 26, 2004).

10.8 ***	Enterprise Products 1998 Long-Term Incentive Plan, amended and restated as of April 8, 2004 (incorporated by reference to Appendix B to Notice of Written Consent dated April 22, 2004, filed April 22, 2004).
10.9 ***	Form of Option Grant Award under 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.3 to Form S-8 Registration Statement, Reg. No. 333-115633, filed May 19, 2004).
10.10***	Form of Restricted Unit Grant under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.3 to Form S-8 Registration Statement, Reg. No. 333-115633, filed May 19, 2004).
10.11***	Letter Agreement dated September 30, 2004, among Enterprise Products Partners L.P., GulfTerra Energy Partners, L.P. and Bart Heijermans (incorporated by reference to Exhibit 10.1 to Form 8-K/A-2 filed on October 18, 2004).
10.12***	1998 Omnibus Compensation Plan of GulfTerra Energy Partners, L.P., Amended and Restated as of January 1, 1999 (incorporated by reference to Exhibit 10.9 to Form 10-K for the year ended December 31, 1998 of GulfTerra Energy Partners, L.P., file no. 001-11680); Amendment No. 1, dated as of December 1, 1999 (incorporated by reference to Exhibit 10.8.1 to Form 10-Q for the quarter ended June 30, 2000 of GulfTerra Energy Partners, L.P., file no. 001-116800); Amendment No. 2 dated as of May 15, 2003 (incorporated by reference to Exhibit 10.M.1 to Form 10-Q for the quarter ended June 30, 2003 of GulfTerra Energy Partners, L.P., file no. 001-11680).
10.13	Second Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC and Enterprise Products OLPGP, Inc., dated effective as of October 1, 2004 (incorporated by reference to Exhibit 10.1 to Form 8-K filed October 27, 2004).
10.14	Amendment No. 1 to Second Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC and Enterprise Products OLPGP, Inc., executed on June 1, 2005, but effective as of February 24, 2005 (incorporated by reference to Exhibit 10.1 to Form 8-K filed June 2, 2005).
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 March 31, 2005 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 March 31, 2005 quarterly report on Form 10-Q.
32.1#	Section 1350 certification of Robert G. Phillips for the March 31, 2005 quarterly report on Form 10-Q.
32.2#	Section 1350 certification of Michael A. Creel for the March 31, 2005 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.
***	Identifies management contract and compensatory plan arrangements.
#	Filed with this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this quarterly report on Form 10-Q to be signed on its behalf by the undersigned thereunto duly authorized, in the City of Houston, State of Texas on August 5, 2005.

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 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: August 5, 2005

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

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: August 5, 2005

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

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 three and six months ended June 30, 2005 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: August 5, 2005

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 three and six months ended June 30, 2005 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: August 5, 2005