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

FORM 10-Q

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

For the quarterly period ended September 30, 2004 or

[ ] 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 [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

YES [X] NO [ ]

There were 361,986,867 common units of *Enterprise Products Partners L.P.* outstanding at November 4, 2004. Enterprise Products Partners L.P.'s common units trade on the New York Stock Exchange under symbol the "EPD."

ENTERPRISE PRODUCTS PARTNERS L.P.
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Glossary

The following abbreviations, acronyms or terms used in this Form 10-Q are defined below:

Acadian Gas	Acadian Gas, LLC and subsidiaries
Accum. OCI (or AOCI)	Accumulated Other Comprehensive Income or Loss, as appropriate
Administrative Services Agreement	Second Amended and Restated Administrative Services Agreement, effective as of October 1, 2004, among EPCO, the Company, the Operating Partnership, the General Partner and the OLP General Partner (formerly, the “EPCO Agreement”)
APB	Accounting Principles Board Opinion
ARB	Accounting Research Bulletin
BBtus	Billion British thermal units, a measure of heating value
Bcf/d	Billion cubic feet per day
BEF	Belvieu Environmental Fuels L.P.
Belle Rose	Belle Rose NGL Pipeline LLC, an equity method investment
BRF	Baton Rouge Fractionators LLC, an equity method investment
BRPC	Baton Rouge Propylene Concentrator, LLC, an equity method investment
Cameron Highway	Cameron Highway Oil Pipeline Company, an equity method investment acquired in connection with the GulfTerra Merger
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CMAI	Chemical Market Associates, Inc.
Coyote	Coyote Gas Treating, LLC, an equity method investment acquired in connection with the GulfTerra Merger
CPG	Cents per gallon
Deepwater Gateway	Deepwater Gateway, L.L.C., an equity method investment acquired in connection with the GulfTerra Merger
Diamond-Koch	Refers to common affiliates of both Valero Energy Corporation and Koch Industries, Inc.
Dixie	Dixie Pipeline Company, an equity method investment
DRIP	Distribution Reinvestment Plan
EITF	Emerging Issues Task Force Issue
El Paso	El Paso Corporation and its affiliates
Enterprise GP	Enterprise Products GP, LLC, the general partner of the Company
EPCO	EPCO, Inc. (formerly Enterprise Products Company), an affiliate of the Company and our ultimate parent company
EPIK	EPIK Terminalling L.P. and EPIK Gas Liquids, LLC, collectively (a former equity method investment in which we acquired the remaining ownership interests in March 2003)
EPOLP	Enterprise Products Operating L.P., the operating subsidiary of the Company (also referred to as the “Operating Partnership”)
Evangeline	Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively, an equity method investment
FASB	Financial Accounting Standards Board
Feedstock	A raw material required for an industrial process such as in petrochemical manufacturing
FIN	Financial Accounting Standards Board Interpretation
Forward sales contracts	The sale of a commodity or other product in a current period for delivery in a future period.
FTC	U.S. Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States of America
GulfTerra	GulfTerra Energy Partners, L.P. and subsidiaries (wholly-owned subsidiary of the Company at September 30, 2004 after completion of the GulfTerra Merger)
GulfTerra GP	GulfTerra Energy Company, L.L.C., the general partner of GulfTerra (wholly-owned subsidiary of the Company at September 30, 2004 after completion of the GulfTerra Merger)

GulfTerra Merger	Refers to Step One, Step Two and Step Three of the merger of GulfTerra with a wholly-owned subsidiary of the Company and the various transactions related thereto. Please read Note 3 of the Notes to Unaudited Condensed Consolidated Financial Statements for a description of Step One, Step Two and Step Three of the GulfTerra Merger.
La Porte	La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively, an equity method investment
LIBOR	London interbank offered rate
MBA	Mont Belvieu Associates, see “MBA acquisition” below
MBA acquisition	Refers to the acquisition of Mont Belvieu Associates' remaining interest in the Mont Belvieu NGL fractionation facility in 1999
MBFC	Mississippi Business Finance Corporation
MBPD	Thousand barrels per day
Mid-America	Mid-America Pipeline Company, LLC
Mmcf	Million cubic feet
Mont Belvieu	Mont Belvieu, Texas
Moody’s	Moody’s Investors Service
MTBE	Methyl tertiary butyl ether
Nemo	Nemo Gathering Company, LLC, an equity method investment
Neptune	Neptune Pipeline Company, L.L.C., an equity method investment
NGL or NGLs	Natural gas liquid(s)
NYSE	New York Stock Exchange
OPIS	Oil Price Information Service
Operating Partnership	Enterprise Products Operating L.P. and its affiliates
OTC	Olefins Terminal Corporation
Poseidon	Poseidon Oil Pipeline Company, L.L.C., an equity method investment acquired in connection with the GulfTerra Merger
Promix	K/D/S Promix LLC, an equity method investment
SEC	U.S. Securities and Exchange Commission
Seminole	Seminole Pipeline Company
SFAS	Statement of Financial Accounting Standards issued by the FASB
Shell	Shell Oil Company, its subsidiaries and affiliates
South Texas midstream assets	Refers to midstream energy assets located in South Texas we acquired from El Paso Paso under Step Three of the GulfTerra Merger
Splitter III	Refers to the propylene fractionation facility we acquired from Diamond-Koch
Starfish	Starfish Pipeline Company, LLC, an equity method investment held for sale under an FTC consent decree published for comment on September 30, 2004
Sun	Sunoco Inc. and its affiliates
Throughput	Refers to the physical movement of volumes through a pipeline
TLP	Tension leg platform
Tri-States	Tri-States NGL Pipeline LLC
VESCO	Venice Energy Services Company, LLC, an equity method investment after July 1, 2004
Williams	The Williams Companies, Inc. and its affiliates
Wilprise	Wilprise Pipeline Company, LLC
1998 Plan	EPCO’s 1998 Long-Term Incentive Plan
1999 Trust	EPOLP 1999 Grantor Trust, a subsidiary of EPOLP

For definitions of other commonly used terms used in our industry, please refer to the “Glossary” section of our 2003 annual report on Form 10-K (Commission File No. 1-14323).

PART I. ITEM 1. FINANCIAL STATEMENTS.

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

	September 30, 2004	December 31, 2003
ASSETS		
Current Assets		
Cash and cash equivalents	$ 146,602	$ 30,466
Restricted cash, including $1.1 billion held in escrow for tender offers at September 30, 2004	1,116,887	13,851
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $26,963 at September 30, 2004 and $20,423 at December 31, 2003	811,548	462,198
Accounts receivable - related parties	17,128	347
Inventories	327,016	150,161
Assets held for sale	37,221	
Prepaid and other current assets	72,309	30,160
Total current assets	2,528,711	687,183
Property, Plant and Equipment, net	7,723,701	2,963,505
Investments in and Advances to Unconsolidated Affiliates	464,203	767,759
Intangible Assets, net of accumulated amortization of $51,922 at September 30, 2004 and $40,371 at December 31, 2003	961,862	268,893
Goodwill	445,924	82,427
Deferred Tax Asset	7,265	10,437
Long-term Receivables	28,012	5,454
Other Assets	23,707	17,156
Total	$ 12,183,385	$ 4,802,814
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Current maturities of debt	$ 607,212	$ 240,000
Accounts payable - trade	76,136	68,384
Accounts payable - related parties	31,567	38,045
Accrued gas payables	921,109	622,982
Accrued expenses and other current liabilities	180,113	127,465
Total current liabilities	1,816,137	1,096,876
Long-Term Debt	4,972,150	1,899,548
Other Long-Term Liabilities	54,239	14,081
Minority Interest	61,289	86,356
Commitments and Contingencies		
Partners' Equity		
Common units (360,052,673 units outstanding at September 30, 2004 and 213,366,760 at December 31, 2003)	5,159,572	1,582,951
Restricted common units (168,300 units outstanding at September 30, 2004)	4,827	
Class B special units (4,413,549 units outstanding at December 31, 2003)		100,182
Treasury units, at cost (505,713 units outstanding at September 30, 2004 and 798,313 units at December 31, 2003)	(10,323)	(16,519)
General Partner	105,395	34,349
Accumulated other comprehensive income	24,084	4,990
Deferred compensation	(3,985)	
Total Partners' Equity	5,279,570	1,705,953
Total	$ 12,183,385	$ 4,802,814

See Notes to Unaudited Condensed Consolidated Financial Statements

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	**2003**	**2004**	**2003**
REVENUES				
Third parties	$ 1,801,946	$ 1,044,044	$ 4,862,082	$ 3,484,134
Related parties	238,325	190,736	596,425	442,891
Total	2,040,271	1,234,780	5,458,507	3,927,025
COST AND EXPENSES				
Operating costs and expenses				
Third parties	1,704,953	1,001,717	4,537,821	3,108,114
Related parties	246,614	176,986	688,571	591,323
Total operating costs and expenses	1,951,567	1,178,703	5,226,392	3,699,437
Selling, general and administrative costs				
Third parties	4,352	203	8,266	8,386
Related parties	5,724	7,212	18,363	20,553
Total selling, general and administrative costs	10,076	7,415	26,629	28,939
Total costs and expenses	1,961,643	1,186,118	5,253,021	3,728,376
EQUITY IN INCOME (LOSS) OF UNCONSOLIDATED AFFILIATES	14,581	(18,040)	42,224	(16,647)
OPERATING INCOME	93,209	30,622	247,710	182,002
OTHER INCOME (EXPENSE)				
Interest expense	(32,471)	(32,559)	(96,956)	(107,750)
Dividend income from unconsolidated affiliates		156		4,551
Interest income	579	223	902	587
Other, net	17	77	23	(15)
Other expense	(31,875)	(32,103)	(96,031)	(102,627)
INCOME (LOSS) BEFORE PROVISION FOR INCOME TAXES, MINORITY INTEREST AND CHANGES IN ACCOUNTING PRINCIPLES	61,334	(1,481)	151,679	79,375
PROVISION FOR INCOME TAXES	(662)	(1,023)	(2,706)	(4,628)
INCOME (LOSS) BEFORE MINORITY INTEREST AND CHANGES IN ACCOUNTING PRINCIPLES	60,672	(2,504)	148,973	74,747
MINORITY INTEREST	(3,149)	(757)	(6,847)	(4,398)
INCOME (LOSS) BEFORE CHANGES IN ACCOUNTING PRINCIPLES	57,523	(3,261)	142,126	70,349
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES (see Note 1)	3,768		10,781	
NET INCOME (LOSS)	$ 61,291	$ (3,261)	$ 152,907	$ 70,349
Cash flow hedges	(85,126)		19,405	5,354
Amortization of cash flow hedges	(105)	(99)	(311)	3,296
COMPREHENSIVE INCOME (LOSS)	$ (23,940)	$ (3,360)	$ 172,001	$ 78,999
ALLOCATION OF NET INCOME (LOSS) TO:				
Limited partners' interest in net income (loss)	$ 53,349	$ (8,273)	$ 130,803	$ 56,123
General partner interest in net income (loss)	$ 7,942	$ 5,012	$ 22,104	$ 14,226
EARNINGS PER UNIT: (see Note 14)				
Basic income (loss) per unit before changes in accounting principles and general partner interest	$ 0.23	$ (0.02)	$ 0.61	$ 0.36
Basic net income (loss) per unit, net of general partner interest	$ 0.21	$ (0.04)	$ 0.56	$ 0.29
Diluted income (loss) per unit before changes in accounting principles and general partner interest	$ 0.23	$ (0.02)	$ 0.61	$ 0.35
Diluted net income (loss) per unit, net of general partner interest	$ 0.21	$ (0.04)	$ 0.56	$ 0.28

See Notes to Unaudited Condensed Consolidated Financial Statements

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

	For the Nine Months Ended September 30,	
	2004	**2003**
OPERATING ACTIVITIES		
Net income	$ 152,907	$ 70,349
Adjustments to reconcile net income to cash flows provided by operating activities:		
Depreciation and amortization in operating costs and expenses	94,674	83,761
Depreciation in selling, general and administrative costs	302	83
Amortization in interest expense	2,868	12,237
Equity in (income) loss of unconsolidated affiliates	(42,224)	16,647
Distributions received from unconsolidated affiliates	54,580	25,703
Provision for impairment of long-lived asset	4,016	
Cumulative effect of changes in accounting principles	(10,781)	
Operating lease expense paid by EPCO	6,820	6,752
Other expenses paid by EPCO		605
Minority interest	6,847	4,398
Loss (gain) on sale of assets	158	(67)
Deferred income tax expense	6,293	4,182
Changes in fair market value of financial instruments	82	(25)
Increase in restricted cash used for operating activities	(3,036)	(5,904)
Net effect of changes in operating accounts (see Note 11)	(240,526)	3,944
Cash provided by operating activities	32,980	222,665
INVESTING ACTIVITIES		
Capital expenditures	(38,945)	(97,968)
Proceeds from sale of assets	110	177
Cash used for business combinations, net of cash received	(695,284)	(26,255)
Investments in and advances to unconsolidated affiliates	(579)	(29,414)
Cash used in investing activities	(734,698)	(153,460)
FINANCING ACTIVITIES		
Borrowings under debt agreements	3,588,000	1,326,210
Repayments of debt	(2,164,677)	(1,683,000)
Debt issuance costs	(3,450)	(7,773)
Borrowing proceeds held in escrow for tender offers	(1,100,000)	
Distributions paid to partners	(278,582)	(223,416)
Distributions paid to minority interests	(5,325)	(7,202)
Contributions from minority interests and general partner	50	5,601
Proceeds from sales of common units	755,933	540,154
Treasury units reissued	6,500	1,282
Settlement of cash flow hedging financial instruments	19,405	5,354
Cash provided by (used in) financing activities	817,854	(42,790)
NET CHANGE IN CASH AND CASH EQUIVALENTS	116,136	26,415
CASH AND CASH EQUIVALENTS, JANUARY 1	30,466	13,817
CASH AND CASH EQUIVALENTS, SEPTEMBER 30	$ 146,602	$ 40,232

See Notes to Unaudited Condensed Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY
(Dollars in thousands, see Note 9 for unit history)

	Limited Partners							
	Common units	Restricted common units	Class B special units	General Partner	Treasury units	Deferred Comp.	Accum. OCI	Total
Balance, January 1, 2004	$1,582,951		$100,182	$ 34,349	$(16,519)		$ 4,990	$1,705,953
Net income	128,788	$ 21	1,994	22,104				152,907
Operating leases paid by EPCO	6,583	1	100	136				6,820
Cash distributions to partners	(250,646)	(30)	(3,288)	(24,618)				(278,582)
Proceeds from sales of common units	740,814			15,119				755,933
Conversion of Class B special units to common units	98,993		(98,993)					
Value of equity interests granted to complete the GulfTerra Merger	2,851,795	2,389		58,249		$ (1,666)		2,910,767
Other issuance of restricted units		2,446		51		(2,461)		36
Amortization of deferred compensation						142		142
Treasury unit transactions:								
- Reissued to satisfy unit options					6,196			6,196
- Gain on reissued treasury units	294		5	5				304
Interest rate hedging financial instruments recorded as cash flow hedges:								
- Cash gains on settlement							19,405	19,405
- Amortization of 2003 gain as component of interest expense							(311)	(311)
Balance, September 30, 2004	$5,159,572	$ 4,827	$ -	$105,395	$(10,323)	$ (3,985)	$ 24,084	$5,279,570

See Notes to Unaudited Condensed Consolidated Financial Statements

1. GENERAL

ENTERPRISE PRODUCTS PARTNERS L.P. is a publicly traded Delaware limited partnership listed on the 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. Certain abbreviated entity names and other capitalized and industry terms are defined within the glossary of this quarterly report on Form 10-Q.

We were formed in April 1998 to own and operate certain NGL-related businesses of EPCO, Inc. (“EPCO,” formerly Enterprise Products Company). We conduct substantially all of our business through a 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.

On September 30, 2004, we completed Step Two and Step Three of the GulfTerra Merger. For additional information regarding these events, please see Note 3.

In the opinion of Enterprise, the accompanying unaudited condensed consolidated financial statements include all adjustments consisting of normal recurring accruals necessary for a 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 GAAP have been condensed or omitted pursuant to the rules and regulations of the SEC. These unaudited condensed financial statements should be read in conjunction with our annual report on Form 10-K (File No. 1-14323) for the year ended December 31, 2003.

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 financial information of our Operating Partnership.

The results of operations for the three and nine month periods ended September 30, 2004 are not necessarily indicative of the results to be expected for the full year. For information regarding the pro forma effects of the GulfTerra Merger on our historical results of operations, see Note 3.

Dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars, unless otherwise indicated.

Certain reclassifications have been made to the prior year’s financial statements to conform to the current year presentation. As a result of the GulfTerra Merger, we have revised and renamed our reportable business segments, as discussed in Note 13. We have revised our prior segment financial information, to the extent practicable, in order to conform to the current business segment presentation.

CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES represents the combined impact of (1) changing 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 (2) changing the method in which we account for our investment in VESCO from the cost method to the equity method.

Our BEF subsidiary owns an octane additive production facility that undergoes periodic planned outages of 30 to 45 days for major maintenance work. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services, and other related items. BEF used the accrue-in-advance method to record cost estimates for such activities; whereas, the Company's other operations used the expense-as-incurred method for their planned major maintenance activities. Our BEF subsidiary changed its accounting method on January 1, 2004 to conform to the Company's accounting for planned major maintenance costs, which better reflects expenses in the period incurred. As such, we believe the change is to a method that is preferable in the circumstances. The cumulative effect of this accounting change for years prior to 2004 resulted in a benefit of $7 million.

EITF 03-16, "*Accounting for Investments in Limited Liability Companies*," requires investments in limited liability companies (or "LLCs") that have separate ownership accounts for each investor be accounted for similar to limited partnerships under SOP No. 78-9, "*Accounting for Investments in Real Estate Ventures*." Under this new guidance (applicable for the period beginning July 1, 2004), investors are required to apply the equity method of accounting to their investments at a much lower ownership threshold (typically any ownership interest greater than 3-5%) than the traditional 20% threshold applied under APB Opinion No. 18, "*The Equity Method of Accounting for Investments in Common Stock*."

Prior to July 1, 2004, we accounted for our 13.1% investment in VESCO using the cost method. As a result, we recognized dividend income from VESCO to the extent that we received cash distributions from them. In accordance with the new accounting guidance in EITF 03-16, we recorded a cumulative effect adjustment equal to the difference between (i) equity earnings from VESCO that would have been recorded using the equity method in periods prior to July 1, 2004 and (ii) the dividend income from VESCO we recorded using the cost method in prior periods. The cumulative effect of this accounting change resulted in a benefit of $3.8 million.

For the periods indicated, the following table shows pro forma net income and earnings per unit amounts assuming the accounting changes noted above were applied retroactively to January 1, 2003. See Note 14 for information regarding the effect of the accounting changes on basic and diluted earnings per unit.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	2003	2004	2003
Pro Forma income statement amounts:				
Historical net income (loss)	$ 61,291	$ (3,261)	$ 152,907	$ 70,349
Adjustments to derive pro forma net income:				
Effect of changing from the accrue-in-advance method to the expense-as-incurred method for BEF major maintenance costs:				
Remove historical equity in losses recorded for BEF		21,195		27,864
Record equity earnings from BEF calculated using new method of accounting for major maintenance costs		(20,962)		(28,187)
Remove cumulative effect of change in accounting principle recorded on January 1, 2004			(7,013)	
Remove minority interest expense associated with change in accounting principle - Sun 33.3% portion			2,338	
Effect of changing from the cost method to the equity method with respect to our investment in VESCO:				
Remove cumulative effect of change in accounting principle recorded on July 1, 2004	(3,768)		(3,768)	
Remove historical dividend income recorded from VESCO			(2,136)	(4,395)
Record equity earnings from VESCO		1,028	2,429	3,562
Pro forma net income (loss)	57,523	(2,000)	144,757	69,193
Enterprise GP interest	(7,866)	(5,025)	(21,941)	(14,214)
Pro forma net income (loss) available to limited partners	$ 49,657	$ (7,025)	$ 122,816	$ 54,979
Pro forma per unit data (basic):				
Historical units outstanding	249,287	207,801	232,707	195,388
Per unit data:				
As reported	$ 0.21	$ (0.04)	$ 0.56	$ 0.29
Pro forma	$ 0.20	$ (0.03)	$ 0.53	$ 0.28
Pro forma per unit data (diluted):				
Historical units outstanding	249,750	207,801	233,193	203,816
Per unit data:				
As reported	$ 0.21	$ (0.04)	$ 0.56	$ 0.28
Pro forma	$ 0.20	$ (0.03)	$ 0.53	$ 0.27

NATURAL GAS IMBALANCES result from differences in gas volumes received from and delivered to our customers and arise when a customer delivers more or less gas into our pipelines than they take out. We estimate the value of our imbalances at prices representing the estimated value of the imbalances upon settlement. Changes in natural gas prices may impact our estimates. We do not value our imbalances based on current month-end spot prices because it is not likely that we would purchase or receive natural gas at that point in time to settle the imbalance. Prior to the GulfTerra Merger, natural gas imbalances were not a significant part of our business.

Natural gas imbalances are reflected in accounts receivable or accounts payable, as appropriate, in our accompanying Unaudited Condensed Consolidated Balance Sheet. At September 30, 2004, our imbalance receivables were $42.5 million and our imbalance payables were $71.4 million.

UNIT OPTION PLAN ACCOUNTING is based on the intrinsic-value method described in 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 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 September 30,		For the Nine Months Ended September 30,	
	2004	**2003**	**2004**	**2003**
Historical net income (loss)	$ 61,291	$ (3,261)	$ 152,907	$ 70,349
Additional unit option-based compensation expense estimated using fair value-based method	(233)	(277)	(700)	(830)
Pro forma net income (loss)	61,058	(3,538)	152,207	69,519
Less incentive earnings allocations to Enterprise GP	(6,853)	(5,096)	(19,435)	(13,659)
Pro forma net income (loss) after incentive earnings allocation	54,205	(8,634)	132,772	55,860
Multiplied by Enterprise GP ownership interest	2.0%	1.0%	2.0%	1.0%
Standard earnings (loss) allocation to Enterprise GP	$ 1,084	$ (86)	$ 2,655	$ 559
Incentive earnings allocation to Enterprise GP	$ 6,853	$ 5,096	$ 19,435	$ 13,659
Standard earnings (loss) allocation to Enterprise GP	1,084	(86)	2,655	559
Enterprise GP interest in pro forma net income (loss)	$ 7,937	$ 5,010	$ 22,090	$ 14,218
Pro forma net income (loss)	$ 61,058	$ (3,538)	$ 152,207	$ 69,519
Less Enterprise GP interest in pro forma net income (loss)	(7,937)	(5,010)	(22,090)	(14,218)
Pro forma net income (loss) available to limited partners	$ 53,121	$ (8,548)	$ 130,117	$ 55,301
Basic earnings (loss) per unit, net of Enterprise GP interest:				
Historical units outstanding	249,287	207,801	232,707	195,388
As reported	$ 0.21	$ (0.04)	$ 0.56	$ 0.29
Pro forma	$ 0.21	$ (0.04)	$ 0.56	$ 0.28
Diluted earnings (loss) per unit, net of Enterprise GP interest:				
Historical units outstanding	249,750	207,801	233,193	203,816
As reported	$ 0.21	$ (0.04)	$ 0.56	$ 0.28
Pro forma	$ 0.21	$ (0.04)	$ 0.56	$ 0.27

We recorded compensation expense of $0.1 million during the three and nine months ended September 30, 2004 in connection with our issuance of restricted common units to key management personnel in May and September 2004 (see Note 9).

2. RECENTLY ISSUED ACCOUNTING STANDARDS

FIN 46, "*Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51.*" This interpretation of ARB No. 51 addresses requirements for accounting consolidation of a variable interest entity ("VIE") with its primary beneficiary. In general, if an equity owner of a VIE meets certain criteria defined within FIN 46, the assets, liabilities and results of the activities of the VIE should be included in the consolidated financial statements of the owner. Our adoption of FIN 46 (as amended by FIN 46R) in 2003 has had no material effect on our consolidated financial statements. Due to the complexity of FIN 46 (as amended by FIN 46R and interpreted), the FASB is continuing to provide guidance regarding implementation issues. Since this guidance is still continuing, our conclusions regarding the application of this guidance may be altered. As a result, adjustments may be recorded in future periods as we adopt new FASB interpretations of FIN 46.

EITF 03-06, "*Participating Securities and the Two-Class Method under SFAS No. 128.*" This accounting guidance, which is applicable for the period beginning April 1, 2004, requires the two-class method for calculating earnings per share for certain securities that are considered to participate in earnings with common shareholders. Under the two-class method, distributions to equity owners are subtracted from earnings, and any remaining earnings would be allocated to the various classes of owners in proportion to their right to receive distributions as if those earnings had been distributed. The total distributions to each class of owner plus the amount allocated to each class would be used to compute earnings per unit for that class. Since our distributions to owners exceeded earnings during the periods presented, as has historically been the case, the two-class method did not produce any change from the way we have traditionally computed earnings per unit. As a result, our adoption of this standard had no effect on our earnings per unit calculations.

3. BUSINESS COMBINATIONS

Completion of the GulfTerra Merger

General

On September 30, 2004, Enterprise and GulfTerra completed the merger of GulfTerra with a wholly-owned subsidiary of Enterprise, with GulfTerra being the surviving entity thereof. Additionally, Enterprise completed certain other transactions related to the merger, including receipt of Enterprise GP's contribution of a 50% membership interest in GulfTerra GP, which was acquired by Enterprise GP from El Paso, and the purchase of certain midstream energy assets located in South Texas from El Paso. The aggregate value of the total consideration Enterprise paid or issued to complete the GulfTerra Merger was approximately $4 billion. These transactions were accounted for using purchase accounting.

Our September 30, 2004 Unaudited Condensed Consolidated Balance Sheet reflects the GulfTerra Merger. Since the GulfTerra Merger closed during the day of September 30, 2004, our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income do not include any earnings from GulfTerra due to the immateriality of the amounts. Pursuant to written agreements, the effective closing date of our purchase of the South Texas midstream assets was September 1, 2004. Our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income for the three and nine months ended September 30, 2004 include one month of results of operations from the South Texas midstream assets.

As a result of the GulfTerra Merger, GulfTerra and GulfTerra GP became wholly-owned subsidiaries of Enterprise on September 30, 2004. On October 1, 2004, we contributed our ownership interests in GulfTerra and GulfTerra GP to our Operating Partnership, which resulted in GulfTerra and GulfTerra GP becoming wholly-owned subsidiaries of the Operating Partnership.

Overview of the GulfTerra and South Texas midstream assets

GulfTerra owns or has interests in natural gas pipeline systems extending over 15,650 miles. These pipeline systems include natural gas gathering systems located onshore in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas and offshore in active drilling and development regions in the Gulf of Mexico. GulfTerra also owns interests in five natural gas processing and treating plants in New Mexico, Texas and Colorado.

In addition, GulfTerra has interests in seven multi-purpose offshore hub platforms in the Gulf of Mexico, including the recently completed Marco Polo TLP. These platforms were specifically designed to be used as deepwater hubs and production handling and pipeline maintenance facilities. Many of GulfTerra's offshore natural gas and oil pipelines utilize these platforms.

GulfTerra also owns two salt dome natural gas storage facilities in Mississippi that are connected to five interstate pipeline systems, have a combined current working capacity of 13.5 Bcf and are capable of delivering in excess of 1.2 Bcf/d of natural gas. In addition, GulfTerra has the exclusive right to use a natural gas storage facility in South Texas under an operating lease that expires in January 2008. This facility has a working gas capacity of 6.4 Bcf and a maximum withdrawal capacity of 0.8 Bcf/d of natural gas.

In addition, GulfTerra owns interests in four offshore crude oil pipeline systems, which extend over 380 miles, and recently completed construction of the 390-mile Cameron Highway oil pipeline. GulfTerra also owns over 1,000 miles of intrastate NGL pipelines and four NGL fractionation plants in Texas; a 3.3 MMBbl propane storage facility in Mississippi; and, owns or leases NGL storage facilities in Louisiana and Texas with aggregate capacity of approximately 21.3 MMBbls. GulfTerra also owns interests in four relatively insignificant oil and natural gas producing properties located in the Gulf of Mexico offshore Louisiana.

The South Texas midstream assets purchased from El Paso consist of nine natural gas processing plants with a combined capacity of 1.9 Bcf/d, a 294-mile natural gas gathering system, a natural gas treating facility with a capacity of 150 MMcf/d and a small NGL pipeline.

The GulfTerra Merger transactions

The GulfTerra Merger occurred in several interrelated transactions as described below.

- *Step One*. On December 15, 2003, Enterprise purchased a 50% membership interest in GulfTerra GP from El Paso for $425 million in cash. GulfTerra GP owns a 1% general partner interest in GulfTerra. Prior to completion of the GulfTerra Merger, Enterprise accounted for its investment in GulfTerra GP using the equity method of accounting. The $425 million in funds required to complete Step One were borrowed under an Interim Term Loan and our pre-merger revolving credit facilities. This borrowed amount was fully repaid with the net proceeds from equity offerings completed during the first nine months of 2004. See Note 10 for additional information regarding changes in our debt obligations since December 31, 2003.

- *Step Two*. On September 30, 2004, the GulfTerra Merger was consummated and GulfTerra and GulfTerra GP became wholly-owned subsidiaries of Enterprise. Step Two of the GulfTerra Merger included the following transactions:

    - Immediately prior to closing the GulfTerra Merger, Enterprise GP acquired El Paso's remaining 50% membership interest in GulfTerra GP for $370 million in cash paid to El Paso and the issuance of a 9.9% membership interest in Enterprise GP to El Paso. Subsequently, Enterprise GP contributed this 50% membership interest in GulfTerra GP to us without the receipt of additional general partner interest, common units or other consideration. Enterprise GP borrowed the foregoing $370 million from Dan Duncan LLC (which owns a 4.505% membership interest in Enterprise GP), which obtained the funds from a loan from EPCO (which indirectly owns an 85.595% membership interest in Enterprise GP).

- Immediately prior to closing the GulfTerra Merger, Enterprise paid $500 million in cash to El Paso for 10,937,500 Series C units of GulfTerra and 2,876,620 common units of GulfTerra. The remaining 57,762,369 GulfTerra common units (7,433,425 of which were owned by El Paso) were converted into 104,549,823 Enterprise common units (13,454,499 of which are held by El Paso) at the time of the consummation of the GulfTerra Merger.

- *Step Three*. Immediately after Step Two was completed, Enterprise acquired certain South Texas midstream assets from El Paso for $155.3 million in cash, which was effective September 1, 2004 and is subject to post-closing adjustments.

In connection with the closing of the GulfTerra Merger, on September 30, 2004, our Operating Partnership borrowed an aggregate $2.8 billion under its new revolving credit facilities in order to fund its cash payment obligations under Step Two and Step Three of the GulfTerra Merger and related transactions, including the tender offers for GulfTerra's outstanding senior and senior subordinated notes. See Note 10 and 17 for a description of these new borrowing and debt-related transactions.

The total consideration paid or granted for the GulfTerra Merger is summarized below:

Step One transaction:	
Cash payment by Enterprise to El Paso for initial 50% membership interest in GulfTerra GP (a non-voting interest) made in December 2003	$ 425,000
Total Step One consideration	425,000
Step Two transactions:	
Cash payment by Enterprise to El Paso for 10,937,500 GulfTerra Series C units and 2,876,620 GulfTerra common units	500,000
Fair value of equity interests granted to acquire remaining 50% membership interest in GulfTerra GP (voting interest) (1)	461,347
Fair value of Enterprise common units issued in exchange for remaining GulfTerra common units (see Note 9)	2,445,420
Fair value of other Enterprise equity interests granted for unit awards and Series F2 convertible units	4,000
Fair value of receivable from El Paso for transition support payments (2)	(40,313)
Transaction fees and other direct costs incurred by Enterprise as a result of the GulfTerra Merger (3)	22,572
Total Step Two consideration	3,393,026
Total Step One and Step Two consideration	3,818,026
Step Three transaction:	
Purchase of South Texas midstream assets from El Paso	155,277
Total consideration for Steps One through Three	$3,973,303

(1) This preliminary fair value is based on 50% of an implied $922.7 million total value of GulfTerra GP, which assumes that the $370 million cash payment made by Enterprise GP to El Paso represented consideration for a 40.1% interest in GulfTerra GP. The 40.1% interest was derived by deducting the 9.9% membership interest in Enterprise GP granted to El Paso in this transaction from the 50% membership interest in GulfTerra GP that Enterprise GP received. The preliminary fair value of $461.3 million assigned to this voting membership interest in GulfTerra GP compares favorably to the $425 million paid to El Paso by Enterprise to purchase its initial 50% non-voting membership interest in GulfTerra GP in December 2003.

(2) Reflects the present value of a contract-based receivable from El Paso received as part of the negotiated net consideration reached in Step One of the GulfTerra Merger. The agreements between Enterprise and El Paso provide that for a period of three years following the closing of the GulfTerra Merger, El Paso will make transition support payments to Enterprise in annual amounts of $18 million, $15 million and $12 million for the first, second and third years of such period, respectively, payable in twelve equal monthly installments for each such year. The $45 million receivable from El Paso has been discounted to fair value and recorded as a reduction in the purchase consideration for GulfTerra. As of September 30, 2004, the fair value of the current portion and non-current portion of this contract-based receivable was $17.2 million and $23.1 million, respectively; these amounts are reflected as a component of "Prepaid and other current assets" and "Long-term receivables" on our Unaudited Condensed Consolidated Balance Sheet as of September 30, 2004.

(3) As a result of the GulfTerra Merger, Enterprise incurred expenses of approximately $23 million for various transaction fees and other direct costs. These direct costs include fees for legal, accounting, printing, financial advisory and other services rendered by third-parties to Enterprise over the course of the GulfTerra Merger transactions. This amount also includes $3.4 million of involuntary severance costs.

Other agreements associated with the GulfTerra Merger

Enterprise GP Exchange Agreement with El Paso. An El Paso subsidiary (“El Paso Holdco”) that owns the 9.9% membership interest in Enterprise GP entered into an Exchange and Registration Rights Agreement (the “Exchange Agreement”) with Enterprise and Enterprise GP dated September 30, 2004, pursuant to which El Paso Holdco has the right to deliver its 9.9% membership interest to Enterprise GP at any time after March 31, 2005 in exchange for a number of Enterprise common units that would provide the same cash flow as its 9.9% membership interest in Enterprise GP. Enterprise GP may elect to pay El Paso Holdco cash in lieu of Enterprise common units equal to the market value of such Enterprise common units or a combination of cash and Enterprise common units. If El Paso Holdco has not exercised the foregoing right by March 31, 2008, Enterprise GP can force the exercise of such right at any time thereafter. We have agreed in the Exchange Agreement to file a shelf registration statement covering the resale of any Enterprise common units that may be delivered to El Paso Holdco upon the exercise of the foregoing exchange right. DFI Delaware Holdings L.P., an entity controlled by Dan L. Duncan that owns 115,540,924 Enterprise common units at September 30, 2004, has guaranteed the performance of Enterprise GP’s obligations under the Exchange Agreement pursuant to a Performance Guaranty dated September 30, 2004.

Enterprise Registration Rights Agreement with El Paso. Enterprise and El Paso entered into a Registration Rights Agreement dated September 30, 2004, pursuant to which Enterprise granted to El Paso one demand registration statement and unlimited piggyback registration rights with respect to the 13,454,499 Enterprise common units received by El Paso pursuant to the GulfTerra Merger. The piggyback rights so granted to El Paso are subordinated to the piggyback rights of an affiliate of Shell set forth in the Registration Rights Agreement dated September 17, 1999.

Other business acquisitions completed during the nine months ended September 30, 2004

During the first nine months of 2004, we also acquired an additional 16.7% interest in Tri-States, a 10% interest in Seminole and the remaining 33.3% ownership interest in BEF. Due to the immaterial nature of each these acquisitions, individually and in the aggregate, our discussion of each of these transactions is limited to the following:

Acquisition of 16.7% interest in Tri-States. On April 1, 2004, we acquired an additional 16.7% membership interest in Tri-States, which owns an NGL pipeline located along the Mississippi, Alabama and Louisiana Gulf Coast. This system, in conjunction with the Wilprise and Belle Rose NGL pipelines, transport mixed NGLs to the BRF, Norco and Promix NGL fractionators located in south Louisiana. Due to this acquisition, our ownership interest in Tri-States increased to 66.7% and Tri-States became a majority-owned consolidated subsidiary of ours on April 1, 2004. Previously, Tri-States was accounted for as an equity method unconsolidated affiliate.

Acquisition of 10% interest in Seminole. On May 31, 2004, we acquired an additional 10% interest in Seminole, which owns a regulated 1,281-mile pipeline that transports mixed NGLs and NGL products from the Hobbs hub on the Texas-New Mexico border and the Permian Basin area to southeast Texas. As a result of this acquisition, our ownership interest in Seminole increased to 88.4%. The Seminole pipeline is interconnected with our Mid-America pipeline system at the Hobbs hub. The primary source of throughput for Seminole is volume originating from the Mid-America system.

Acquisition of remaining 33.3% interest in BEF. On September 1, 2004, we acquired the remaining 33.3% ownership interest in BEF, which owns a facility that produces octane additives such as MTBE (a motor gasoline additive that enhances octane and is used in reformulated gasoline). As a result of this acquisition, BEF became a wholly-owned subsidiary of ours.

Allocation of purchase price of 2004 business combinations

The GulfTerra Merger transactions and our other business acquisitions completed during the first nine months of 2004 were recorded using the purchase method of accounting. Purchase accounting requires us to allocate the cost of a business combination to the assets acquired and liabilities assumed based on their estimated fair values. Enterprise has engaged an independent third-party business valuation expert to assess the fair value of

GulfTerra's and the South Texas midstream assets' tangible and intangible assets. This information will assist management in the development of a definitive allocation of the overall purchase price of the GulfTerra Merger transactions. Management independently developed the fair value estimates for the other 2004 business acquisitions using recognized business valuation techniques.

The preliminary fair values shown in the following table are initial estimates based on information available to management at September 30, 2004. The tentative fair value conclusions and allocations related to the GulfTerra Merger transactions will be updated when the underlying valuation study is finalized, which is expected to occur during the fourth quarter of 2004 and we have completed our review of all other related information. The valuation estimates shown below will likely change due to this very recent transaction and the refinement of our initial estimates.

	GulfTerra Merger Transactions			
	Step Two of GulfTerra Merger	Step Three Purchase of South Texas Midstream Assets	Other 2004 Business Combinations	Total
Purchase price allocation:				
Assets acquired in business combination:				
Current assets, including cash of $40,453	$ 228,180	$ 7,614	$ 7,475	$ 243,269
Property, plant and equipment, net	4,584,705	126,913	69,872	4,781,490
Investments in and advances to unconsolidated affiliates	209,317		(42,597)	166,720
Intangible assets	681,361	23,719	(560)	704,520
Other assets	4,392			4,392
Total assets acquired	5,707,955	158,246	34,190	5,900,391
Liabilities assumed in business combination:				
Current liabilities	(195,458)	(2,969)	(2,329)	(200,756)
Long-term debt, including current maturities (1)	(2,015,583)			(2,015,583)
Other long-term liabilities	(42,385)			(42,385)
Minority interest			26,589	26,589
Total liabilities assumed	(2,253,426)	(2,969)	24,260	(2,232,135)
Total assets acquired less liabilities assumed	3,454,529	155,277	58,450	3,668,256
Total consideration given	3,818,026	155,277	58,450	4,031,753
Goodwill	$ 363,497	$ -	$ -	$ 363,497

(1) Represents GulfTerra's outstanding senior and senior secured note obligations prior to the completion of Enterprise's tender offers on October 5, 2004 (see Note 17). This amount also includes GulfTerra's outstanding obligations under its revolving credit facility and secured term loans prior to Enterprise's repayment of these debt obligations, which occurred on the GulfTerra Merger closing date.

As a result of the preliminary purchase price allocation for Steps Two and Three of the GulfTerra Merger, we recorded $705.1 million of amortizable intangible assets, primarily those related to customer relationships and contracts. The remaining preliminary amount represents goodwill of $363.5 million associated with our view of the future results from GulfTerra's operations, based on the strategic location of GulfTerra's assets as well as their industry connections. For additional information regarding these intangible assets and goodwill, see Note 7.

Pro forma financial information

The following table presents selected unaudited pro forma financial information incorporating the historical (pre-merger) results of GulfTerra and the South Texas midstream assets. Since the GulfTerra Merger closed during the day on September 30, 2004, our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income do not include any earnings from GulfTerra due to the immateriality of the amounts. The effective closing date of our purchase of the South Texas midstream assets was September 1, 2004. As a result, our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income for the three and nine months ended September 30, 2004 include one month of results of operations from the South Texas midstream assets. The pro forma impact of our other business acquisitions is not material to this presentation.

The following pro forma information has been prepared as if the GulfTerra Merger and related transactions had been completed on January 1, 2003 as opposed to the actual dates that these acquisitions occurred. Excluded from the 2004 amounts are approximately $20 million of nonrecurring merger-related costs incurred by GulfTerra. The pro forma information is based upon preliminary data currently available and includes certain estimates and assumptions made by management. As a result, this preliminary information is not necessarily indicative of our financial results had the transactions actually occurred on this date. Likewise, the following unaudited pro forma financial information is not necessarily indicative of our future financial results (dollars in millions, except per unit amounts).

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	**2003**	**2004**	**2003**
Pro forma earnings data:				
Revenues	$2,512.5	$1,673.2	$6,798.4	$5,330.6
Costs and expenses	$2,347.4	$1,557.7	$6,355.4	$4,985.1
Operating income	$ 173.3	$ 100.7	$ 460.8	$ 338.4
Income before extraordinary items	$ 100.7	$ 27.1	$ 261.3	$ 118.3
Net income	$ 100.7	$ 27.1	$ 261.3	$ 118.3
Pro forma net income	$ 100.7	$ 27.1	$ 261.3	$ 118.3
Less incentive earnings allocations to Enterprise GP	(10.4)	(8.9)	(31.1)	(24.3)
Pro forma net income after incentive earnings allocation	90.3	18.2	230.2	94.0
Multiplied by Enterprise GP ownership interest	2.0%	2.0%	2.0%	2.0%
Standard earnings allocation to Enterprise GP	$ 1.8	$ 0.4	$ 4.6	$ 1.9
Incentive earnings allocation to Enterprise GP	$ 10.4	$ 8.9	$ 31.1	$ 24.3
Standard earnings allocation to Enterprise GP	1.8	0.4	4.6	1.9
Enterprise GP interest in pro forma net income	$ 12.2	$ 9.3	$ 35.7	$ 26.2
Pro forma net income	$ 100.7	$ 27.1	$ 261.3	$ 118.3
Less Enterprise GP interest in pro forma net income	(12.2)	(9.3)	(35.7)	(26.2)
Pro forma net income available to limited partners	$ 88.5	$ 17.8	$ 225.6	$ 92.1
Basic earnings per unit, net of Enterprise GP interest:				
As reported basic units outstanding	249.3	207.8	232.7	195.4
Pro forma basic units outstanding	360.0	356.2	359.9	344.3
As reported basic net income per unit	$ 0.21	$ (0.04)	$ 0.56	$ 0.29
Pro forma basic net income per unit	$ 0.25	$ 0.05	$ 0.63	$ 0.27
Diluted earnings per unit, net of Enterprise GP interest:				
As reported pro forma units outstanding	249.8	207.8	233.2	203.8
Pro forma diluted units outstanding	360.4	359.6	360.3	352.7
As reported diluted net income per unit	$ 0.21	$ (0.04)	$ 0.56	$ 0.28
Pro forma diluted net income per unit	$ 0.25	$ 0.05	$ 0.63	$ 0.26

4. INVENTORIES

Our inventories (including the preliminary purchase price allocations of $13.8 million from Steps Two and Three of the GulfTerra Merger at September 30, 2004) were as follows at the dates indicated:

	September 30, 2004	December 31, 2003
Working inventory	$ 259,061	$ 135,451
Forward-sales inventory	67,955	14,710
Inventory	$ 327,016	$ 150,161

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.

Due to fluctuating conditions in the NGL, natural gas and petrochemical industry, we occasionally recognize lower of average cost or market (“LCM”) adjustments when the cost of our inventories exceed their net realizable value. These non-cash adjustments are charged to operating costs and expenses in the period they are recognized. For the three months ended September 30, 2004 and 2003, we recognized $0.1 million and $0.7 million, respectively, of LCM adjustments. We recorded $6.1 million and $15.1 million of LCM adjustments for the nine months ended September 30, 2004 and 2003, respectively.

5. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment (including the preliminary purchase price allocations of $4.7 billion from Steps Two and Three of the GulfTerra Merger at September 30, 2004) and accumulated depreciation were as follows at the dates indicated:

	September 30, 2004	December 31, 2003
Plants and pipelines	$ 7,657,274	$ 3,214,463
Underground and other storage facilities	529,526	288,199
Platforms and facilities	143,940	
Transportation equipment	6,951	5,676
Oil and natural gas properties	15,886	
Land	29,638	23,447
Construction in progress	80,655	74,431
Total	8,463,870	3,606,216
Less accumulated depreciation	740,169	642,711
Property, plant and equipment, net	$ 7,723,701	$ 2,963,505

Depreciation expense for the three months ended September 30, 2004 and 2003 was $28.6 million and $24.7 million, respectively. We recorded $83.3 million and $73.1 million of such expense for the nine months ended September 30, 2004 and 2003, respectively.

Other long-term liabilities on our September 30, 2004 Unaudited Condensed Consolidated Balance Sheet includes $6.1 million related to historical asset retirement obligations recorded by GulfTerra. These asset retirement obligations have been recorded in accordance with SFAS No. 143, “*Accounting for Asset Retirement Obligation*s,” and relate primarily to plugging abandoned offshore wells located in the Gulf of Mexico offshore Louisiana.

In connection with the GulfTerra Merger, we are required under a consent decree published for comment by the FTC on September 30, 2004 to sell our undivided 50% ownership interest in a Mississippi propane storage facility by December 31, 2004. As a result of our initial estimate of this asset's current anticipated sales price, we recorded a non-cash asset impairment charge of $4 million during the third quarter of 2004, which is a component of operating costs and expenses of our NGL Pipelines & Services business segment. The nominal fair value of this facility was reclassified from "Property, Plant and Equipment" to "Assets Held for Sale" on our Unaudited Condensed Consolidated Balance Sheet at September 30, 2004. The operating results of this facility (including the aforementioned asset impairment charge) are not material to our historical or ongoing operations; therefore, these results have not been presented as discontinued operations in our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income.

In connection with the GulfTerra Merger, we also acquired interests in four relatively insignificant oil and natural gas producing properties located in the Gulf of Mexico offshore Louisiana. Production from these properties is generally gathered, transported, and processed through our pipeline systems and platform facilities, and sold to various third parties. These oil and gas producing properties are not a significant part of our business and we do not expect them to become significant in the future. Our intent is to diminish these activities over time by not acquiring additional properties. We will use the successful efforts method to account for the costs of such oil and natural gas assets. Depletion charges related to these properties will be based on the units-of-production method.

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. In general, we use the equity method of accounting for an investment in which we own 20% to 50% of its outstanding ownership interests and exercise significant influence over its operating and financial policies. As a result of recently issued accounting guidance under EITF 03-16 (see Note 1), the minimum ownership requirement for an investment organized as a LLC to qualify for the equity method of accounting was lowered to between 3% and 5% from the 20% threshold applied to other types of investments.

On July 1, 2004, we changed our method of accounting for VESCO from the cost method to the equity method in accordance with EITF 03-16. The VESCO investment consists of a 13.1% interest in a LLC that owns a natural gas processing plant, NGL fractionation facilities, storage assets and gas gathering pipelines located in south Louisiana. For additional information regarding this change in accounting method, see Note 1.

As a result of the GulfTerra Merger (see Note 3), we acquired ownership interests in the entities described below, all of which are unconsolidated affiliates accounted for using the equity method of accounting. We do not exercise management control over these entities and are therefore precluded from consolidating their financial statements with those of our own.

- *Cameron Highway Oil Pipeline Company* ("Cameron Highway") – a 50% interest in Cameron Highway, which owns a recently constructed crude oil pipeline system that connects various designated crude oil receipt points extending from Ship Shoal Block 332 in the Gulf of Mexico to onshore delivery points located in the state of Texas. We anticipate that operations will commence on this pipeline system during the fourth quarter of 2004 or early 2005.

- *Deepwater Gateway, L.L.C.* ("Deepwater Gateway") – a 50% interest in Deepwater Gateway, which owns the Marco Polo TLP. The Marco Polo TLP is operated by Anadarko Petroleum Corporation ("Anadarko") and processes oil and natural gas from Anadarko's Marco Polo Field discovery located at Green Canyon Block 608 in the Gulf of Mexico. The Marco Polo TLP went into service during the third quarter of 2004.

- *Poseidon Oil Pipeline Company, L.L.C.* ("Poseidon") – a 36% interest in Poseidon, which owns a crude oil pipeline extending from the Gulf of Mexico to onshore Louisiana. Poseidon completed construction of its Front Runner oil pipeline, an extension of the Poseidon oil pipeline, in the third quarter of 2004 and first production is anticipated in the fourth quarter of 2004. This new oil pipeline connects the Front Runner platform in the Gulf of Mexico with Poseidon's existing system.

- *Coyote Gas Treating, LLC* ("Coyote") – a 50% interest in Coyote, which owns a natural gas treating facility located in the San Juan Basin of southwestern Colorado.

In connection with the GulfTerra Merger, we are required under a consent decree published for comment by the FTC on September 30, 2004 to sell our 50% interest in Starfish, which in turn owns the Stingray natural gas pipeline and related gathering pipelines and dehydration and other facilities located in south Louisiana and the Gulf of Mexico offshore Louisiana. The carrying value of this investment was reclassified from "Investments in and Advances to Unconsolidated Affiliates" to "Assets Held for Sale" on our Unaudited Condensed Consolidated Balance Sheet at September 30, 2004. We are required to sell this investment by March 31, 2005.

Our investments in and advances to these unconsolidated affiliates are grouped in the following table according to the new business segment to which they relate. For a general discussion of our business segments, see Note 13.

	Ownership Percentage at September 30, 2004	Investments in and advances to Unconsolidated Affiliates at	
		September 30, 2004	**December 31, 2003**
Offshore Pipelines & Services:			
Poseidon (1)	36.0%	$ 61,422	
Cameron Highway (1)	50.0%	86,000	
Deepwater Gateway (1)	50.0%	49,141	
Other offshore pipelines (2)	Various	84,515	$ 127,605
Onshore Natural Gas Pipelines & Services:			
Evangeline	49.5%	2,965	2,519
Coyote (1)	50.0%	12,755	
NGL Pipelines & Services:			
Dixie	19.9%	34,009	35,988
VESCO	13.1%	36,589	33,000
Belle Rose	41.7%	10,251	10,780
Promix	33.3%	38,486	38,903
BRF	32.3%	27,154	27,892
Tri-States (3)			44,119
Petrochemical Services:			
BRPC	30.0%	15,808	16,584
La Porte	50.0%	5,108	5,422
Other:			
GulfTerra GP (4)			424,947
Total		$ 464,203	$ 767,759

(1) Our ownership interest in these investments was acquired in connection with the GulfTerra Merger on September 30, 2004. We have made a preliminary allocation of the purchase consideration to these investments based on estimated values at the GulfTerra Merger date.

(2) Reflects our collective investment in Neptune, Nemo and Starfish. In connection with the GulfTerra Merger, we are required under a consent decree published for comment by the FTC on September 30, 2004 to sell our 50% interest in Starfish. The carrying value of this asset was reclassified from "Investments in and Advances to Unconsolidated Affiliates" to "Assets Held for Sale" on our Unaudited Condensed Consolidated Balance Sheet at September 30, 2004.

(3) We acquired an additional 16.7% ownership interest in Tri-States in April 2004. As a result of this acquisition, Tri-States became a consolidated subsidiary.

(4) In connection with the GulfTerra Merger (see Note 3), GulfTerra GP became a wholly-owned consolidated subsidiary of ours on September 30, 2004. GulfTerra GP was a 50% owned, equity method investment of ours from December 15, 2003 through September 29, 2004.

The following table shows our equity in income (loss) of unconsolidated affiliates for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	2003	2004	2003
Offshore Pipelines & Services:				
Offshore pipeline investments (1)	$ 720	$ 1,648	$ 2,576	$ 5,420
Onshore Natural Gas Pipelines & Services:				
Evangeline	158	108	314	144
NGL Pipelines & Services:				
Dixie	107	366	499	739
VESCO	1,920		4,056	
Belle Rose	(81)	(20)	(289)	(137)
Promix	155	676	539	1,270
BRF	598	227	1,698	308
Tri-States (2)		52	(154)	1,176
Wilprise (2)		83		276
EPIK (2)				1,818
Petrochemical Services:				
BRPC	440	231	1,521	773
La Porte	(195)	(159)	(561)	(493)
BEF (2)		(21,195)		(27,864)
OTC (2)		(57)		(77)
Other:				
GulfTerra GP (3)	10,759		32,025	
Total	$ 14,581	$ (18,040)	$ 42,224	$ (16,647)

(1) Reflects combined equity earnings from Neptune, Nemo and Starfish. In connection with the GulfTerra Merger, we are required under a consent decree published for comment by the FTC on September 30, 2004 to sell our 50% interest in Starfish.

(2) We acquired additional ownership interests in or control over these entities since January 1, 2003 resulting in our consolidation of each company’s post-acquisition financial results with those of our own. Our consolidation of each company's post-acquisition financial results began in the following periods: EPIK, March 2003; Wilprise, October 2003; OTC, August 2003; BEF, September 2003; and Tri-States, April 2004.

(3) In connection with the GulfTerra Merger (see Note 3), GulfTerra GP became a wholly-owned consolidated subsidiary of ours on September 30, 2004. GulfTerra GP was a 50% owned, equity method investment of ours from December 15, 2003 through September 29, 2004.

Summarized financial information of unconsolidated affiliates

The following table presents unaudited summarized income statement information for our unconsolidated affiliates from which we have recorded equity earnings (for the periods indicated, on a 100% basis).

	Summarized Income Statement Information for the Three Months Ended					
	September 30, 2004			September 30, 2003		
	Revenues	Operating Income	Net Income	Revenues	Operating Income (Loss)	Net Income (Loss)
Offshore Pipelines & Services	$ 14,640	$ 3,463	$ 3,376	$ 13,679	$ 5,466	$ 5,301
Onshore Natural Gas Pipelines & Services	78,560	1,951	155	69,780	2,155	249
NGL Pipelines & Services (1)						
From current equity investments	73,162	12,192	11,310	27,222	7,513	5,706
From prior equity investments				2,403	379	379
Petrochemical Services (1)						
From current equity investments	4,377	1,094	1,104	3,199	471	471
From prior equity investments				48,456	(63,723)	(63,700)
Other, non-segment (2)			21,518			

	Summarized Income Statement Information for the Nine Months Ended					
	September 30, 2004			September 30, 2003		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income (Loss)	Net Income (Loss)
Offshore Pipelines & Services	$ 38,363	$ 7,718	$ 7,052	$ 42,994	$ 17,255	$ 16,072
Onshore Natural Gas Pipelines & Services	195,119	5,773	314	184,755	6,061	332
NGL Pipelines & Services (1)						
From current equity investments	124,607	23,432	19,973	78,021	16,279	11,976
From prior equity investments	1,926	(243)	(243)	17,928	7,889	7,903
Petrochemical Services (1)						
From current equity investments	13,928	4,012	4,023	10,511	1,707	1,657
From prior equity investments				136,240	(83,805)	(83,746)
Other, non-segment (2)			64,049			

(1) Since January 1, 2003, we have acquired additional ownership interests in several equity method unconsolidated affiliates resulting in the consolidation of post-acquisition results of these companies with those of our own. For comparability purposes, we have segregated those entities within each segment into those that we are currently consolidating from those that continue to be recorded using the equity method. The following is a list of the segments and entities affected and the timeframe in which we began consolidating their results with those of our own: NGL Pipelines & Services (EPIK, March 2003; Wilprise, October 2003; and Tri-States, April 2004) and Petrochemical Services (BEF, September 2003; and OTC, August 2003). The table above shows revenues, operating income and net income for the timeframes that we accounted for each investment using the equity method.

(2) In connection with the GulfTerra Merger (see Note 3), GulfTerra GP became a wholly-owned consolidated subsidiary of ours on September 30, 2004. GulfTerra GP was a 50% owned equity method investment of ours from December 15, 2003 through September 29, 2004.

Since the GulfTerra Merger occurred during the day on September 30, 2004, the amount of any equity income (loss) from Cameron Highway, Deepwater Gateway, Poseidon and Coyote was not material. The following unaudited summarized income statement information is presented for informational purposes only (for the periods indicated, on a 100% basis).

Summarized Income Statement Information for the Three Months Ended

	September 30, 2004			September 30, 2003		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income	Net Income
Cameron Highway (1)		$ (346)	$ (290)			
Deepwater Gateway (2)	$ 9,598	7,538	6,124			$ 14
Poseidon	9,399	7,192	6,193	$ 9,425	$ 6,590	5,278
Coyote	1,800	1,339	1,137	1,800	1,185	1,014

Summarized Income Statement Information for the Nine Months Ended

	September 30, 2004			September 30, 2003		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income (Loss)	Net Income
Cameron Highway (1)		$ (728)	$ (588)			
Deepwater Gateway (2)	$ 15,898	11,813	8,924		$ (5)	$ 32
Poseidon	27,515	17,776	14,973	$ 32,632	23,468	19,356
Coyote	5,400	3,922	3,381	5,625	4,078	3,524

(1) Cameron Highway was still in the development stage at September 30, 2004; therefore, there were no operating revenues or operating expenses. Since its formation in June 2003, it has incurred organizational expenses and received interest income. In September 2004, construction of this system was completed and we anticipate that operations will begin during the fourth quarter of 2004 or early 2005.

(2) The Marco Polo TLP, which is the primary asset owned by Deepwater Gateway, was installed in the first quarter of 2004. First production and thus volumetric payments started in July 2004. In April 2004, Deepwater Gateway began receiving monthly demand payments of $2.1 million. Prior to the TLP installation, Deepwater Gateway was a development stage company; therefore, there were no operating revenues or operating expenses. However, it did incur organizational expenses and received interest income.

7. INTANGIBLE ASSETS AND GOODWILL

Intangible assets

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

		At September 30, 2004		At December 31, 2003	
	Gross Value	Accum. Amort.	Carrying Value	Accum. Amort.	Carrying Value
Offshore Pipelines & Services:					
Offshore pipeline & platform customer relationships (1)	$ 210,515		$ 210,515		
Segment total	210,515		210,515		
Onshore Natural Gas Pipelines & Services:					
San Juan gathering system customer relationships (1)	342,940		342,940		
Permian Basin customer relationships (1)	38,745		38,745		
Petal natural gas storage contracts (1)	65,807		65,807		
Hattiesburg natural gas storage contracts (1)	6,460		6,460		
San Juan Basin water rights (1)	750		750		
Segment total	454,702		454,702		
NGL Pipelines & Services:					
Shell natural gas processing agreement	206,216	$ (42,348)	163,868	$ (34,063)	$ 172,153
Toca-Western natural gas processing contracts	11,187	(1,305)	9,882	(885)	10,302
Mont Belvieu Storage II contracts	8,127	(639)	7,488	(464)	7,663
Toca-Western NGL fractionation contracts	20,042	(2,339)	17,703	(1,587)	18,455
Venice contracts	6,635	(484)	6,151	(136)	6,499
STMA customer relationships (2)	23,719	(86)	23,633		
Markham NGL storage contracts (1)	16,144		16,144		
Segment total	292,070	(47,201)	244,869	(37,135)	215,072
Petrochemical Services:					
Mont Belvieu Splitter III contracts	53,000	(4,038)	48,962	(2,902)	50,098
BEF UOP License Fee	1,097	(94)	1,003	(24)	1,633
Port Neches pipeline contracts	2,400	(589)	1,811	(310)	2,090
Segment total	56,497	(4,721)	51,776	(3,236)	53,821
Total all segments	$ 1,013,784	$ (51,922)	$ 961,862	$ (40,371)	$ 268,893

(1) Acquired as a result of the GulfTerra Merger in September 2004; amounts are subject to changes in our preliminary purchase price allocation (see Note 3).

(2) Represents customer relationships associated with the South Texas midstream assets ("STMA"), which we acquired in connection with Step Three of the GulfTerra Merger; amounts are subject to changes in our preliminary purchase price allocation (see Note 3).

As a result of Steps Two and Three of the GulfTerra Merger, we made preliminary purchase price allocations of $705.1 million to acquired intangible assets related to customer relationships, storage contracts, and water rights.

- *Customer relationships.* These intangible assets represent the customer base that GulfTerra and the South Texas midstream assets served through providing services, including natural gas gathering and processing, NGL fractionation and pipeline transportation. These businesses conducted the majority of their business through the use of written contracts; thus, the customer relationships represent the rights we own arising from those contractual agreements. The value of these customer relationships will be amortized on a straight-line basis over the estimated economic life of the resource base to which they relate, which we currently estimate could range from 18 to 43 years depending on the asset.

- *Storage contacts*. These intangible assets represent the contracts that GulfTerra entered into to provide for the storage of natural gas and NGLs at its Petal and Hattiesburg storage facilities, as well as its Markham NGL storage facility. These contracts will be being amortized on a straight-line basis over the remainder of their respective contract terms, which we estimate could range from 2 to 18 years.

- *Water rights*. The water rights we acquired from GulfTerra consist of approximately 3,000 acre-feet of water rights in the San Juan Basin of New Mexico that allow us to drill for and extract groundwater. These water rights will be amortized on a straight-line basis over their estimated useful life, which is currently estimated at 30 years.

For the remainder of 2004, amortization expense attributable to our intangible assets is currently estimated at $11.8 million. Based on information currently available, we estimate that amortization expense related to existing intangible assets could approximate $47 million during 2005 and 2006, $42 million during 2007 and $39 million during 2008 and 2009.

Goodwill

Our preliminary estimate of goodwill associated with the GulfTerra Merger is $363.5 million, which we allocated between our new business segments in proportion to the tangible and intangible assets we recorded for this transaction in purchase accounting. The "GulfTerra Merger" goodwill is associated with our view of the future results from GulfTerra's operations, based on the strategic location of GulfTerra's assets as well as their industry connections. Based on miles of pipelines, GulfTerra is one of the largest natural gas gatherers in the natural gas supply regions offshore in the Gulf of Mexico and onshore in Texas and New Mexico. These regions, especially the deeper water regions of the Gulf of Mexico, offer us significant growth potential through the acquisition and construction of additional pipelines, platforms, processing and storage facilities and other energy infrastructure.

The following table summarizes our goodwill amounts at September 30, 2004 and December 31, 2003:

	September 30, 2004	December 31, 2003
Offshore Pipelines & Services:		
GulfTerra Merger	$ 52,795	
Onshore Natural Gas Pipelines & Services:		
GulfTerra Merger	288,930	
NGL Pipelines & Services:		
GulfTerra Merger	21,772	
MBA acquisition	7,857	$ 7,857
Wilprise acquisition	880	880
Petrochemical Services:		
Splitter III acquisition	73,690	73,690
Totals	$ 445,924	$ 82,427

8. RELATED PARTY TRANSACTIONS

Relationship with EPCO

We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a director and Chairman of Enterprise GP, our general partner. In addition, the executive and other officers of our general partner are employees of EPCO, including O.S. Andras who is Chief Executive Officer and a director and Vice Chairman of Enterprise GP. The principal business activity of our general partner is to act as our managing partner. Collectively, EPCO and its affiliates owned a 36.2% equity interest in Enterprise at September 30, 2004, which includes their ownership interest of Enterprise GP (of which EPCO and its affiliates own 90.1%).

We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the Administrative Services Agreement. Prior to January 1, 2004, we reimbursed EPCO for the costs of its employees who performed operating functions for us and for costs related to certain of its management and administrative personnel hired in response to the expansion of our business. In addition, we paid EPCO a monthly fee for services provided by its other management and administrative employees. On January 1, 2004, the Administrative Services Agreement was amended to eliminate the fee portion of this reimbursement and to provide that we reimburse EPCO for all such costs, including fringe benefits, related to management or administrative support for us.

On October 22, 2004, the Administrative Services Agreement was amended further to evidence our separateness from other persons and entities, to reflect a five-year license we granted for EPCO's use of service marks owned by us and to provide for reimbursement of EPCO's costs of discontinuing the use of those service marks over the term of the license. This amendment also provides that if EPCO and its affiliates are offered by a third party, or discover an opportunity to acquire from a third party, a business or assets that is or are in the same or similar line of business then being conducted by the Operating Partnership or in a line of business that would be a natural extension of any business then being conducted by the Operating Partnership (a "Business Opportunity"), EPCO shall promptly advise the Board of Directors of Enterprise GP of such Business Opportunity and offer such Business Opportunity to the Operating Partnership. If the Board of Directors of Enterprise GP does not advise EPCO within 10 days following the receipt of such notice that we wish to pursue such Business Opportunity, EPCO shall then be permitted to pursue such Business Opportunity. If the Board of Directors of Enterprise GP advises EPCO within the 10 day period that we want to pursue such Business Opportunity, EPCO shall not be permitted to pursue such Business Opportunity unless the Board of Directors of Enterprise GP subsequently advises EPCO that it has abandoned its pursuit of such Business Opportunity.

We also have entered into an agreement with EPCO to provide trucking services to us for the transportation of NGLs and other products. In addition, we also buy from and sell to EPCO's Canadian affiliate certain NGL products.

We and Enterprise GP are each separate legal entities from EPCO and its other affiliates, with assets and liabilities that are separate from EPCO and its other affiliates. EPCO primarily depends on cash distributions it receives as an equity owner in us to fund its other operations and to meet its debt obligations. For the nine months ended September 30, 2004 and 2003, EPCO received $130.6 million and $119.2 million in distributions from us.

Relationship with Shell

We have a significant commercial relationship with Shell as a partner, customer and vendor. At September 30, 2004, Shell owned an approximate 11.1% equity interest in Enterprise. Shell is one of our largest customers. Our revenues from Shell primarily reflect the sale of NGL and petrochemical products to Shell and the fees we charge Shell for natural gas processing, pipeline transportation and NGL fractionation services. Our operating costs and expenses with Shell primarily reflect the payment of energy-related expenses related to the Shell natural gas processing agreement and the purchase of NGL products from Shell.

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 and purchase of NGL storage, transportation and fractionation services from Promix. In addition, we sell natural gas to Promix and process natural gas at VESCO.

The following table summarizes our related party revenues, operating costs and expenses, and selling, general and administrative costs for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	2003	2004	2003
Revenues				
EPCO and affiliates	$ 129	$ 1,255	$ 2,347	$ 2,814
Shell and affiliates	148,821	62,806	397,805	224,242
Unconsolidated affiliates	89,375	126,675	196,273	215,835
Operating costs and expenses				
EPCO and affiliates	49,762	32,097	128,389	111,146
Shell and affiliates	189,442	131,932	536,284	444,873
Unconsolidated affiliates	7,410	12,957	23,898	35,304
Selling, general and administrative costs				
EPCO and affiliates	5,724	7,212	18,363	20,553

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 Enterprise GP, our general partner.

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.

Amendment to Partnership Agreement

On October 1, 2004, we amended and restated our Partnership Agreement by executing the Fourth Amended and Restated Agreement of Limited Partnership. The amended Partnership Agreement makes the following changes: (i) all previous amendments were consolidated into one document, (ii) certain provisions which are no longer applicable to us were deleted (such as those relating to the subordination period and classes of partnership equity securities that are no longer outstanding), and (iii) certain provisions were added to evidence our separateness from other persons and entities. A number of additional immaterial revisions were made in the amended Partnership Agreement, including updating definitions to provide consistency with the above described changes.

Equity interests granted on September 30, 2004 in connection with the GulfTerra Merger

Under Step Two of the GulfTerra Merger (see Note 3), Enterprise issued 1.81 of its common units for each GulfTerra common unit (including restricted common units) remaining after Enterprise's purchase of 2,876,620

GulfTerra common units owned by El Paso. The 104,549,823 Enterprise common units (including restricted common units) issued in the conversion were calculated as shown in the following table:

GulfTerra units outstanding at September 30, 2004:	
Common units, including time-vested restricted units	60,638,989
Series C units	10,937,500
Total historical units outstanding at September 30, 2004	71,576,489
Adjustments to GulfTerra historical units outstanding as a result of the GulfTerra Merger:	
Enterprise's purchase of GulfTerra Series C units from El Paso in connection with Step Two	(10,937,500)
Enterprise's purchase of GulfTerra common units from El Paso in connection with Step Two	(2,876,620)
GulfTerra common units outstanding subject to Step Two exchange offer by Enterprise	57,762,369
Conversion ratio (1.81 Enterprise common units for each GulfTerra common unit)	1.81
Enterprise common units issued to GulfTerra common unitholders in connection with GulfTerra Merger (adjusted for 65 fractional common units)	104,549,823
Average closing price per unit of Enterprise common units immediately prior to and after proposed GulfTerra Merger was announced on December 15, 2003 (see following table)	$ 23.39
Fair value of Enterprise common units issued in conversion of remaining GulfTerra common units	$ 2,445,420

In accordance with purchase accounting rules, the $2.4 billion value of Enterprise’s common units issued in Step Two of the GulfTerra Merger is based on the average closing price of Enterprise’s common units immediately prior to and after the proposed merger was announced on December 15, 2003:

December 11, 2003	$ 23.10
December 12, 2003	22.80
December 16, 2003	23.85
December 17, 2003	23.80
Average closing price per unit of Enterprise common units immediately prior to and after the proposed merger was announced on December 15, 2003	$ 23.39

Overall, the fair value of equity interests we issued on September 30, 2004 under Step Two of the GulfTerra Merger was approximately $2.9 billion. The following table shows the detail for this consideration:

Fair value of Enterprise common units issued in conversion of remaining GulfTerra common units	$2,445,420
Fair value of equity interests issued to acquire remaining 50% membership interest in GulfTerra GP (voting interest) (1)	461,347
Fair value of other Enterprise equity interests issued for unit awards and Series F2 convertible units (2)	4,000
Total value of equity interests issued upon closing of GulfTerra Merger	$2,910,767

(1) This preliminary fair value is based on 50% of an implied $922.7 million total value of GulfTerra GP, which assumes that the $370 million cash payment made by Enterprise GP to El Paso represented consideration for a 40.1% interest in GulfTerra GP. The 40.1% interest was derived by deducting the 9.9% membership interest in Enterprise GP granted to El Paso in this transaction from the 50% membership interest in GulfTerra GP that Enterprise GP received. The preliminary fair value of $461.3 million assigned to this voting membership interest in GulfTerra GP compares favorably to the $425 million paid to El Paso by Enterprise to purchase its initial 50% non-voting membership interest in GulfTerra GP in December 2003.

(2) See discussion of “*Series F2 convertible units assumed in connection with the GulfTerra Merger*” and “*Restricted common units*” included within this Note 9 for additional information.

Series F2 convertible units assumed in connection with the GulfTerra Merger

In May 2003, GulfTerra issued 80 Series F convertible units in a registered offering to an institutional investor. Each Series F convertible unit was comprised of two separate detachable units – a Series F1 convertible unit and a Series F2 convertible unit – that had identical terms except for vesting and termination dates and the number of common units into which they could be converted. Prior to the GulfTerra Merger, all the Series F1 convertible units were converted to GulfTerra common units by the holder. As a result of the GulfTerra Merger, we assumed GulfTerra’s obligation associated with the 80 Series F2 convertible units. All Series F2 convertible units outstanding at the merger date were converted into rights to receive Enterprise common units. The number of Enterprise common units and the price per unit at conversion were adjusted based on the 1.81 exchange ratio. The fair value of the Series F2 convertible units at September 30, 2004 was estimated at $3.4 million.

The Series F2 units were convertible into up to $40 million of Enterprise common units. On October 29, 2004, 60 of the 80 outstanding Series F2 convertible units were converted into 1,458,434 Enterprise common units. On November 8, 2004, the remaining 20 outstanding Series F2 convertible units were converted into 491,883 Enterprise common units. See Note 17 for additional information regarding these conversions.

Restricted common units

In May 2004, EPCO issued 81,500 time-vested restricted units to key management personnel of EPCO (who work on our behalf) as a means of retaining and compensating them for long-term performance and to increase their ownership in the Company. The fair market value of the May 2004 restricted units at grant date was $1.7 million. In September 2004, EPCO issued an additional 86,800 time-vested restricted units to key management personnel, including 54,300 restricted units that were carried forward from pre-GulfTerra Merger agreements between GulfTerra and certain of its key employees (who are now EPCO employees as a result of the GulfTerra Merger). The aggregate fair value of the 86,800 time-vested restricted units issued in September 2004 was $1.7 million.

In general, restricted unit awards entitle recipients to acquire the underlying common units (at no cost to them) once the defined vesting period expires, subject to certain forfeiture provisions. The restrictions on these common units lapse four years from the date of grant. Unearned compensation, representing the fair market value of the restricted units at the date of issuance, is charged to earnings as compensation expense on a straight-line basis over the vesting period. During the vesting period, each holder of restricted units is entitled to receive cash distributions per unit in an amount equal to those received by our common unitholders. For basic and diluted earnings per unit purposes, restricted common units are treated as outstanding units.

As a result of the GulfTerra Merger, we exchanged 30,000 GulfTerra performance-based restricted units for Enterprise performance-based restricted units based on the 1.81 exchange ratio, which resulted in our issuance of 54,300 of such units under our 1998 Plan. At the GulfTerra Merger date, we recorded $0.7 million of deferred compensation for these performance-based restricted units, which is reflected as a reduction of partners' equity and is allocated to our limited and general partners in accordance with their respective ownership interests.

In general, performance-based restricted unit awards entitle recipients to acquire the underlying common units (at no cost to them) if we achieve a specified level of financial performance for certain capital projects during 2007. If we do not reach the specified financial targets by the dates identified within each agreement, these units will be forfeited. Unearned compensation, representing the fair market value of these units at the date of issuance, is charged to earnings as compensation expense on a straight-line basis over the performance period. The performance-based restricted units are not entitled to vote or to receive distributions, until after (and if) we achieve the specified level of target performance. Lastly, performance-based restricted units are counted as outstanding units for dilutive earnings per unit purposes only.

Total unamortized deferred compensation attributable to both classes of restricted units at September 30, 2004 was $4 million. We recorded $0.1 million of compensation expense for the three and nine months ended September 30, 2004 which is reflected as a component of selling, general and administrative expenses. Deferred compensation is reflected as a reduction of partners' equity and is allocated to our limited and general partners in accordance with their respective ownership interests.

Conversion of Class B special units to common units in July 2004

Upon receipt of unitholder approval on July 29, 2004, our 4,413,549 Class B special units converted to an equal number of common units. Prior to their conversion, the Class B special units entitled the holder to the same rights and privileges (other than voting rights) as common unitholders. This conversion resulted in a reclassification of the $99 million capital account balance for the Class B special units to common units.

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 offering from January 1, 2004 through September 30, 2004:

		Net Proceeds from Common Unit Offerings		
Month of offering	**Number of common units issued**	**Contributed by Limited Partners**	**Contributed by General Partner**	**Total**
February 2004 (1)	1,053,861	$ 22,684	$ 463	$ 23,147
May 2004 (2)	17,250,000	346,032	7,062	353,094
May 2004 (1)	1,757,347	34,589	706	35,295
August 2004 (3)	17,250,000	334,358	6,824	341,182
August 2004 (1)	173,033	3,151	64	3,215
Total 2004	37,484,241	$ 740,814	$ 15,119	$ 755,933

(1) These units were issued primarily in connection with our distribution reinvestment plan ("DRIP"). We used the proceeds from these offerings for general partnership purposes. See Note 17 for information regarding our issuance of approximately 2.2 million common units in connection with the DRIP in November 2004.

(2) We used the proceeds from this public offering to repay the $225 million Interim Term Loan and to temporarily reduce borrowings outstanding under our revolving credit facilities.

(3) We used $210 million of the proceeds from this public offering to reduce borrowings outstanding under our revolving credit facilities and the remainder to fund our payment obligations to El Paso under Step Two of the GulfTerra Merger.

During the first nine months of 2004, we reissued 292,600 treasury units at a cost of $6.2 million primarily due to obligations under EPCO employee unit option agreements and recorded a $0.3 million gain on the transactions.

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**	**Class B Special Units (1)**	**Treasury Units**
Balance, January 1, 2004	213,366,760		4,413,549	798,313
Common units issued in February 2004	1,053,861			
Common units issued in connection with May 2004 offering	17,250,000			
Other common units issued in May 2004	1,757,347			
Time-vested restricted common units issued in May 2004		81,500		
Conversion of Class B special units to common units in July 2004	4,413,549		(4,413,549)	
Common units issued in connection with August 2004 offering	17,250,000			
Other common units issued in August 2004	173,033			
Common and time-vested restricted common units issued to GulfTerra unitholders on September 30, 2004 in connection with the GulfTerra Merger	104,495,523	54,300		
Other time-vested restricted common units issued in September 2004		32,500		
Treasury units reissued	292,600			(292,600)
Balance, September 30, 2004	360,052,673	168,300	-	505,713

(1) On July 29, 2004, the Class B special units were converted to common units on a one-for-one basis.

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 October 20, 2004, the Board of Directors of Enterprise GP increased the quarterly cash distribution rate by 6% from $0.3725 per common unit to $0.3950 per common unit, or $1.58 per common unit on an annual basis. Further, the Board of Directors also approved the payment of the quarterly distribution for the quarter ended September 30, 2004, which will be paid on November 5, 2004 to unitholders of record at the close of business on October 29, 2004.

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 January 1, 2003. Information for the first nine months of 2004 has been presented by quarter.

	February 2003 Treasury Locks	Forward-Starting Interest Rate Swaps	AOCI Amounts
Gain on settlement of February 2003 treasury locks	$ 5,354		$ 5,354
Amortization of gain on settlement of cash flow hedge to interest expense	(364)		(364)
Balance, December 31, 2003	4,990		4,990
Amortization of gain on settlement of cash flow hedge to interest expense	(102)		(102)
Fair value of forward-starting interest rate swaps		$ 16,973	16,973
Balance, March 31, 2004	4,888	16,973	21,861
Reclassification of change in fair value		(16,973)	(16,973)
April 2004 cash gain on settlement of forward-starting interest rate swaps		104,531	104,531
Amortization of gain on settlement of cash flow hedge to interest expense	(104)		(104)
Balance, June 30, 2004	4,784	104,531	109,315
September 2004 cash loss on settlement of forward-starting interest rate swaps		(85,126)	(85,126)
Amortization of gain on settlement of cash flow hedge to interest expense	(105)		(105)
Balance, September 30, 2004	$ 4,679	$ 19,405	$ 24,084

10. DEBT OBLIGATIONS

Our debt consisted of the following at the dates indicated:

	September 30, 2004	December 31, 2003
Borrowings under:		
Interim Term Loan, variable rate, repaid in May 2004 (1)		$ 225,000
364-Day Revolving Credit Facility, variable rate, $230 million borrowing capacity, terminated in August 2004 (2)		70,000
Multi-Year Revolving Credit Facility "A", variable rate, $270 million borrowing capacity, terminated in August 2004 (2)		115,000
364-Day Acquisition Revolving Credit Facility, variable rate, due September 2005, $2.25 billion borrowing capacity (3)	$ 2,250,000	
Multi-Year Revolving Credit Facility "B", variable rate, due September 2009, $750 million borrowing capacity (3)	545,000	
Senior Notes A, 8.25% fixed-rate, due March 2005	350,000	350,000
Seminole Notes, 6.67% fixed-rate, $15 million due in December 2004 and 2005 (4)	30,000	30,000
MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed-rate, due February 2013	350,000	350,000
Senior Notes D, 6.875% fixed-rate, due March 2033	500,000	500,000
GulfTerra Senior Subordinated and Senior Notes: (5)		
Senior Notes, 6.25% fixed-rate, due June 2010 (5)	250,000	
Senior Subordinated Notes, 8.50% fixed-rate, due June 2010 (5)	215,915	
Senior Subordinated Notes, 8.50% fixed-rate, due June 2011 (5)	321,600	
Senior Subordinated Notes, 10.625% fixed-rate, due December 2012 (5)	134,000	
Fair value of GulfTerra notes at merger closing date	132,383	
Total principal amount	5,582,898	2,144,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	2,525	1,531
Unamortized balance of decrease in fair value related to hedging a portion of fixed-rate debt	(181)	
Less net unamortized discounts on Senior Notes A, B and D	(5,880)	(5,983)
Subtotal long-term debt	5,579,362	2,139,548
Less current maturities of debt (6)	(607,212)	(240,000)
Long-term debt (6)	$ 4,972,150	$ 1,899,548
Standby letters of credit outstanding (7)	$ 20,850	$ 1,300

(1) We used the proceeds from our May 2004 common unit offering to fully repay and terminate the Interim Term Loan.
(2) These facilities were terminated on September 30, 2004 and replaced by the new $750 million Multi-Year Revolving Credit Facility “B.”
(3) These facilities became effective concurrent with the closing of the GulfTerra Merger on September 30, 2004. The new $750 million Multi-Year Revolving Credit Facility “B” replaced the $230 million 364-Day Revolving Credit Facility and the $270 million Multi-Year Revolving Credit Facility “A.” The $750 million borrowing capacity is reduced by the amount of standby letters of credit outstanding.
(4) Solely as it relates to the assets of our GulfTerra and Seminole subsidiaries, our $5.6 billion in senior indebtedness at September 30, 2004 is structurally subordinated and ranks junior in right of payment to the $1.1 billion of indebtedness of GulfTerra and Seminole.
(5) As a result of closing the GulfTerra Merger on September 30, 2004, we recorded in consolidation GulfTerra’s $921.5 million of outstanding senior subordinated and senior notes. On October 5, 2004, $915 million of GulfTerra’s senior subordinated and senior notes were tendered to the Operating Partnership pursuant to the tender offers. See Note 17 for information regarding this subsequent event.
(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, 2003 reflected our option and ability to convert any revolving credit balance outstanding at maturity under the 364-Day Revolving Credit Facility to a one-year term loan (due October 2005) in accordance with the terms of the agreement. With respect to September 30, 2004, we repaid approximately $2 billion outstanding under the 364-Day Acquisition Revolving Credit Facility using proceeds from our October 4, 2004 long-term senior notes offering (see Note 17), which effectively converts the amount repaid to long-term debt.
(7) We had $100 million of letters of credit capacity available under our new $750 million Multi-Year Revolving Credit Facility “B” at September 30, 2004 and $75 million of letters of credit capacity available under our previous $270 million Multi-Year Revolving Credit Facility “A” at December 31, 2003.

On September 30, 2004, we borrowed approximately $2.25 billion under our new 364-Day Acquisition Revolving Credit Facility and $545 million under our new Multi-Year Revolving Credit Facility "B" to (a) fund $655.3 million in cash payment obligations to El Paso under Steps Two and Three of the GulfTerra Merger transactions, (b) escrow $1.1 billion to finance our tender offers for GulfTerra's senior and senior subordinated notes and (c) extinguish $962 million outstanding under GulfTerra's revolving credit facility and secured term loans. Our long-term debt at September 30, 2004 includes the remaining debt obligations of GulfTerra as appropriate in consolidation.

In October 2004, we used the $1.1 billion in escrowed funds (classified as a component of "Restricted Cash" on our Unaudited Condensed Consolidated Balance Sheet at September 30, 2004) to complete our cash tender offers for substantially all of GulfTerra's senior and senior subordinated notes. In addition, we completed our issuance of $2 billion in Rule 144A private placement senior notes (Senior Notes E, F, G, and H) and used the proceeds to reduce borrowings made under our 364-Day Acquisition Revolving Credit Facility on September 30, 2004. See Note 17 for additional information regarding these subsequent events.

General description of consolidated debt

The following is a summary of the significant aspects of our debt obligations at September 30, 2004:

Parent-Subsidiary guarantor relationships. We act as guarantor of the debt obligations of our Operating Partnership, with the exception of the Seminole Notes and the senior and 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 an effective 86.6% of its capital stock). The senior and senior subordinated notes of GulfTerra are unsecured obligations of GulfTerra (of which we own 100% of its limited and general partnership interests).

364-Day Acquisition Revolving Credit Facility. In August 2004, our Operating Partnership entered into a new 364-day revolving credit agreement. The $2.25 billion Acquisition Revolving Credit Facility is an unsecured 364-day facility that was used to provide interim financing for certain transactions associated with the GulfTerra Merger, the refinancing of GulfTerra's existing secured credit facility and term loans and the purchase of GulfTerra's senior and senior subordinated notes in connection with our tender offers for those notes. This facility became effective concurrent with the closing of the GulfTerra Merger and will mature on September 29, 2005. The Operating Partnership's borrowings under this agreement are unsecured general obligations that are non-recourse to Enterprise GP. We have guaranteed repayment of amounts due under this revolving credit agreement through an unsecured guarantee.

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 (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate plus an applicable margin or (3) a Competitive Bid Rate. For information regarding variable interest rates paid under this revolving credit facility, please read "Information regarding variable interest rates paid" within this Note 10.

This credit agreement provides for the mandatory prepayment of loans and termination of commitments equal to the proceeds from and upon the consummation of any public or private debt or equity offerings by us on or after August 15, 2004, excluding equity issued with respect to our DRIP, employee unit purchase plan and the exercise of any outstanding options with respect to our common units. With the completion of our Rule 144A private placement offering of senior notes on October 4, 2004, we repaid approximately $2 billion borrowed under this facility, which reduced our borrowing capacity under this facility by an equal amount.

This revolving credit agreement contains various covenants related to our ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also requires us to satisfy certain financial covenants at the end of each fiscal quarter. If an event of default (as defined in the agreement) occurs, the Operating Partnership is prohibited from making distributions to us, which would impair our ability to make distributions to our partners. As defined in the agreement, we must maintain a specified level of consolidated net worth and certain financial ratios.

Multi-Year Revolving Credit Facility "B". In August 2004, our Operating Partnership entered into a five-year $750 million revolving credit agreement that includes a sublimit of $100 million for standby letters of credit. This facility became effective concurrent with the closing of the GulfTerra Merger and will mature on September 30, 2009. This facility replaced our existing $270 million Multi-Year Revolving Credit Facility "A" and $230 million 364-Day Revolving Credit facility, which were terminated upon the effective date of the new facility. The Operating Partnership's borrowings under this agreement are unsecured general obligations that are non-recourse to Enterprise GP. We have guaranteed repayment of amounts due under this revolving credit agreement through an unsecured guarantee.

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 (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate plus an applicable margin or (3) a Competitive Bid Rate. We elect the basis of the interest rate at the time of each borrowing. For information regarding variable interest rates paid under this revolving credit facility, please read "Information regarding variable interest rates paid" within this Note 10. This revolving credit agreement contains various covenants similar to those of our 364-Day Acquisition Revolving Credit Facility (please refer to our discussion regarding the restrictive covenants of the 364-Day Acquisition Revolving Credit Facility within this Note 10).

Senior Notes Offering. On September 23, 2004, our Operating Partnership priced a Rule 144A private placement of an aggregate of $2 billion in principal amount of four series of senior unsecured notes in a transaction exempt from the registration requirements under the Securities Act of 1933, as amended. See Note 17 for information regarding our Operating Partnership's issuance and sale of these senior unsecured notes on October 4, 2004.

GulfTerra's Senior Subordinated and Senior Notes. At the close of the GulfTerra Merger on September 30, 2004, we recorded in consolidation the outstanding senior subordinated and senior notes of GulfTerra totaling approximately $921.5 million. See Note 17 for information regarding our Operating Partnership's tender offers for all of GulfTerra's outstanding senior subordinated and senior notes and its purchase of $915 million of such notes on October 5, 2004.

Industrial Development Revenue Bonds. In April 2004, Petal Gas Storage L.L.C. ("Petal"), a wholly-owned subsidiary of GulfTerra, borrowed $52 million from the Mississippi Business Finance Corporation ("MBFC") pursuant to a loan agreement between Petal and the MBFC. On the same date, the MBFC issued $52 million in Industrial Development Revenue Bonds to another wholly-owned subsidiary of GulfTerra. The loan agreement and the Industrial Development Revenue Bonds have identical fixed interest rates of 6.25% and maturities of fifteen years. The bonds and the associated tax exemptions are authorized under the Mississippi Business Finance Act. Petal may repay the loan agreement without penalty, and thus cause the Industrial Development Revenue Bonds to be redeemed, any time after one year from their date of issue. We have netted the loan amount and the bond amount of $52 million and the interest payable and interest receivable amount of $1.4 million on our Unaudited Condensed Consolidated Balance Sheet as of September 30, 2004. Beginning in the fourth quarter of 2004, we will also net the interest expense and interest income amounts attributable to these instruments on our Statements of Consolidated Operations. Our presentation of the Industrial Development Revenue Bonds is reflected in accordance with the provisions of FIN No. 39, "*Offsetting of Amounts Related to Certain Contracts*", and SFAS No. 140, "*Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*", since we have the ability and intent to offset these items.

Covenants. We were in compliance with the various covenants of our debt agreements at September 30, 2004 and December 31, 2003.

Loss due to write-off of unamortized debt issuance costs. As a result of terminating our 364-Day Revolving Credit Facility and our Multi-Year Revolving Credit Facility "A" on September 30, 2004, we expensed $0.7 million of unamortized debt issuance costs, which is reflected as a component of interest expense on our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rates paid on our variable rate debt obligations during the nine months ended September 30, 2004:

	Range of interest rates paid	Weighted-average interest rate paid
Interim Term Loan (terminated May 2004)	1.72% to 1.78%	1.73%
364-Day Revolving Credit Facility (terminated September 30, 2004)	1.72% to 4.00%	1.82%
Multi-Year Revolving Credit Facility "A" (terminated September 30, 2004)	1.67% to 4.25%	1.83%
364-Day Acquisition Revolving Credit Facility (effective September 30, 2004)	4.75%	4.75% (1-day only)
Multi-Year Revolving Credit Facility "B" (effective September 30, 2004)	4.75%	4.75% (1-day only)

Consolidated debt maturity table

The following table shows aggregate maturities of the principal amounts of long-term debt and other financing obligations for the remainder of 2004 and the following 4 years and in total thereafter at September 30, 2004 (i) on an actual basis and (ii) on a pro forma basis adjusted for debt-related subsequent events as described in Note 17.

	Historical September 30, 2004	Adjustments for Subsequent Events	Pro Forma September 30, 2004
2004	$ 15,000		$ 15,000
2005	2,614,983	$ (1,981,000) (1)	607,212
		(26,771) (2)	
2006	n/a		n/a
2007	n/a	500,000 (3)	500,000
2008	n/a		n/a
Thereafter	2,952,915	1,500,000 (3)	3,405,486
		(915,046) (4)	
		(132,383) (5)	
Total long-term debt, including current maturities	$ 5,582,898	$ (1,055,200)	$ 4,527,698

(1) Reflects the use of net proceeds from the October 2004 Senior Notes offering to reduce amounts outstanding under the $2.25 billion 364-Day Acquisition Revolving Credit Facility.
(2) Reflects the repayment of excess funds borrowed on September 30, 2004 under the 364-Day Acquisition Revolving Credit Facility.
(3) Reflects the issuance of Senior Notes E, F, G and H on October 4, 2004.
(4) Reflects the completion by our Operating Partnership of its tender offers to purchase $915 million of GulfTerra's senior and senior subordinated notes on October 5, 2004, which are eliminated in consolidation.
(5) Reflects the payment by our Operating Partnership of the premium associated with its tender offers completed on October 5, 2004.

Joint venture debt obligations

As a result of the GulfTerra Merger, we acquired ownership interests in three additional joint ventures having long-term debt obligations. The following table shows (i) our ownership interest in each entity at September 30, 2004, (ii) total long-term debt obligations (including current maturities) of each unconsolidated affiliates on that date on a 100% basis to the joint venture, (ii) the corresponding scheduled maturities of such long-term debt:

	Our Ownership Interest	Total	Scheduled Maturities of Long-Term Debt 2004	2005	2006	2007	2008	After 2008
Cameron Highway (1)	50.0%	$297,000			$16,250	$32,500	$156,250	$ 92,000
Deepwater Gateway	50.0%	149,500	$ 5,500	$22,000	22,000	22,000	22,000	56,000
Poseidon (2)	36.0%	116,000					116,000	
Evangeline	49.5%	40,650	5,000	5,000	5,000	5,000	5,000	15,650
Total		$ 603,150	$10,500	$27,000	$43,250	$59,500	$299,250	$163,650

(1) Cameron Highway has a total borrowing capacity under its project loan facility (as described below) of $325 million. The scheduled maturities for the Cameron Highway assume that the construction loan is or will be converted into a term loan on September 30, 2005 and the scheduled repayments will begin on December 31, 2007.

(2) Poseidon has a total borrowing capacity of $170 million under its revolving credit facility.

The following is a summary of the significant aspects of the debt obligations of our unconsolidated affiliates. For a description of the business activities of the unconsolidated affiliates acquired as a result of the GulfTerra Merger, see Note 6.

Cameron Highway. At September 30, 2004, long-term debt for Cameron Highway consisted of $197 million outstanding under a construction loan and $100 million of senior secured notes (collectively, the “project loan facility”). Cameron Highway has a borrowing capacity of $225 million under its construction loan.

The construction loan bears interest at a variable rate. Once the Cameron Highway oil pipeline has commenced operations and transported a certain level of volumes (as specified in the credit agreement), the construction loan will convert to a term loan maturing in July 2008, subject to the terms of the loan agreement. At the end of the first quarter following the first anniversary of the conversion into a term loan, Cameron Highway will be required to make quarterly principal payments of $8.1 million, with the remaining unpaid principal amount payable on the maturity date. If the construction loan fails to convert into a term loan by January 2006, the construction loan and senior secured notes become fully due and payable. At September 30, 2004, the average interest rate charged under the construction loan was 4.97%.

The interest rate on Cameron Highway’s senior secured notes is 3.25% over the rate on 10-year U.S. Treasury securities. Principal payments of $4 million are due quarterly from September 2008 through December 2011, $6 million each from March 2012 through December 2012, and $5 million each from March 2013 through the principal maturity date of December 2013. At September 30, 2004, Cameron Highway had $100 million outstanding under its senior secured notes at an average interest rate of 7.4%.

The project loan facility as a whole is secured by (1) substantially all of Cameron Highway’s assets, including, upon conversion to a term loan, a debt service reserve capital account, and (2) all of the equity interest in Cameron Highway. Other than the pledge of our equity interest and our construction obligations under the relevant producer agreements, the debt is non-recourse to us. The construction loan and senior secured notes prohibit Cameron Highway from making distributions to us until the construction loan is converted into a term loan and Cameron Highway meets certain financial requirements.

Deepwater Gateway. At September 30, 2004, long-term debt for Deepwater Gateway consisted of $149.5 million due under a project finance loan used to fund a substantial portion of the cost to construct the Marco Polo TLP and related facilities. Construction of the Marco Polo TLP was completed during the first quarter of 2004, and in June 2004, Deepwater Gateway converted the project finance loan into a term loan which matures in June 2009. The term loan is payable in twenty equal quarterly installments of $5.5 million each (which began on September 30, 2004), and the remaining outstanding principal of $45 million is due on the maturity date. Interest rates are variable and the loan is collateralized by substantially all of Deepwater Gateway's assets. If Deepwater Gateway defaults on its payment obligations under the term loan, we would be required to pay the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. As of September 30, 2004, the average interest rate charged under this term loan was 3.6% and Deepwater Gateway had not paid GulfTerra or any of its subsidiaries any distributions.

Poseidon. At September 30, 2004, long-term debt for Poseidon consisted of $116 million due under a revolving credit facility which matures in January 2008. This credit facility has a borrowing capacity of $170 million. The interest rates Poseidon is charged on balances outstanding under its revolving credit facility are variable and depend on its ratio of total debt to earnings before interest, taxes, depreciation and amortization. This credit agreement is secured by substantially all of Poseidon's assets. As of September 30, 2004, the average interest rate charged under this facility was 3.7%.

Evangeline. At September 30, 2004, long-term debt for Evangeline consisted of (i) $33.2 million in principal amount of 9.9% fixed-rate Series B senior secured notes that are due in December 2010 and (ii) a $7.5 million subordinated note payable. The Series B senior secured notes are collateralized by Evangeline's property, plant and equipment; proceeds from a gas sales contract; and by a debt service requirement. Scheduled principal repayments on the Series B notes are $5 million annually through 2009 with a final repayment in 2010 of approximately $3.2 million. The trust indenture governing the Series B notes contains covenants such as requirements to maintain certain financial ratios. Evangeline incurred the subordinated note payable in connection with its acquisition of a contract-based intangible asset in the early 1990s. This note is subject to a subordination agreement which prevents the repayment of principal and accrued interest on the note until such time as the Series B note holders are either fully cash secured through debt service accounts or have been completely repaid. In general, interest accrues on the subordinated note at a variable-rate based on LIBOR plus ½%. The variable interest rate paid on this debt at September 30, 2004 was 1.8%.

11. SUPPLEMENTAL CASH FLOWS DISCLOSURE

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

	For the Nine Months Ended September 30,	
	2004	**2003**
Decrease (increase) in:		
Accounts and notes receivable	$ (207,169)	$ 34,613
Inventories	(187,519)	18,861
Prepaid and other current assets	6,229	10,256
Other assets	(195)	(72)
Increase (decrease) in:		
Accounts payable	(26,235)	(14,677)
Accrued gas payable	197,116	(18,353)
Accrued expenses and other current liabilities	(22,345)	(25,888)
Other liabilities	(408)	(796)
Net effect of changes in operating accounts	$ (240,526)	$ 3,944

We completed the GulfTerra Merger and a number of other business acquisitions during the first nine months of 2004. These transactions affected a number of balance sheet categories. See Note 3 for the preliminary purchase price allocations related to these transactions which include non-cash consideration for equity interests issued and the fair values of assets acquired and liabilities assumed. In addition, see Note 9 for information regarding changes in our partners' equity accounts as a result of the GulfTerra Merger transactions, including amounts associated with unit awards and Series F2 convertible units.

We recorded certain fair value amounts related to our interest rate hedging financial instruments during the first nine months of 2004 that affected various balance sheet accounts. For information regarding our financial instruments, see Note 12.

Restricted cash related to operating activities was $16.9 million at September 30, 2004 and $13.9 million at December 31, 2003. These balances are related to amounts held by a brokerage firm as margin deposits associated with our financial instruments portfolio and for the physical purchase of natural gas made on the NYMEX exchange.

On September 30, 2004, we borrowed $1.1 billion under our 364-Day Acquisition Revolving Credit Facility in anticipation of completing our tender offers for GulfTerra's senior and senior subordinated notes and placed these funds in escrow. On October 5, 2004, our Operating Partnership purchased the tendered notes for a total price of approximately $1.1 billion, which includes accrued interest and consent payments (see Note 17). The $1.1 billion held in escrow is a component of restricted cash on our September 30, 2004 Unaudited Condensed Consolidated Balance Sheet.

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, cash flows and fair value of certain debt securities caused by changes in commodity prices and interest rates. As a matter of policy, we do not use financial instruments for speculative (or "trading") purposes.

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

Changes in the fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instruments meet those criteria, the instrument's gains and losses offset the related results of the hedged item in earnings for a fair value hedge and are deferred in other comprehensive income for a cash flow hedge. Gains and losses related to a cash flow hedge are reclassified into earnings when the forecasted transaction affects earnings.

To qualify as a hedge, the item to be hedged must be exposed to commodity or interest rate risk and the hedging instrument must reduce the exposure and meet the hedging requirements of SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" (as amended and interpreted). We must formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at inception and on a quarterly basis. Any ineffectiveness of the hedge is recorded in current earnings.

Due to the complexity of SFAS No. 133 (as amended and interpreted), the FASB is continuing to provide guidance regarding the implementation of this accounting standard. Since this guidance is still continuing, our conclusions about the application of SFAS No. 133 may be altered, which may result in adjustments being recorded in future periods as we adopt new FASB interpretations of this standard.

Interest rate risk hedging program

Our interest rate exposure results from variable and fixed rate borrowings under debt agreements. We assess the cash flow risk related to interest rates by identifying and measuring changes in our interest rate exposures that may impact future cash flows and evaluating hedging opportunities to manage these risks. We use analytical techniques to measure our exposure to fluctuations in interest rates, including cash flow sensitivity analysis models to forecast the expected impact of changes in interest rates on our future cash flows. Enterprise GP oversees the strategies associated with these financial risks and approves instruments that are appropriate for our requirements.

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. We believe that it is prudent to maintain an appropriate balance of variable rate and fixed rate debt in the current business climate.

Fair value hedges – Interest rate swaps. On January 8, 2004, we entered into three interest rate swap agreements in which we exchanged the payment of fixed rate interest on a portion of principal outstanding under Senior Notes B and C for variable rate interest. On October 7, 2004, we entered into three additional interest rate swap agreements related to a portion of the principal outstanding under Senior Notes G issued on October 4, 2004.

Hedged Fixed Rate Debt	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	Jan. 2004 to Feb.2011	Feb. 2011	7.50% to 5.3%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	Jan. 2004 to Feb.2013	Feb. 2013	6.375% to 3.9%	$100 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	Jan. 2004 to Feb.2013	Feb. 2013	6.375% to 3.9%	$100 million
Senior Notes G 5.6% fixed rate, due Oct. 2014	Oct. 2004 to Oct. 2014	Oct. 2014	5.6% to 3.2%	$100 million
Senior Notes G 5.6% fixed rate, due Oct. 2014	Oct. 2004 to Oct. 2014	Oct. 2014	5.6% to 3.2%	$100 million
Senior Notes G 5.6% fixed rate, due Oct. 2014	Oct. 2004 to Oct. 2014	Oct. 2014	5.6% to 3.2%	$100 million

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

We have designated these six 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. As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

These six agreements have a combined notional amount of $550 million and match the maturity dates of the underlying debt being hedged. Under each swap agreement, we 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 based on the stated interest rate of the debt being hedged, with both payments calculated using the notional amounts stated in each swap agreement. We settle amounts receivable from or payable to the counterparties every six months (the “settlement period”). The settlement amount is amortized ratably to earnings as either an increase or a decrease in interest expense over the settlement period.

Total fair value of the interest rate swaps in effect at September 30, 2004 was a receivable of approximately $1 million with an offsetting increase in fair value of the underlying debt. Interest expense in our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income for the three and nine months ended September 30, 2004 reflects a $1.7 million and $5.3 million benefit, respectively, from these swaps.

Cash flow hedges – Forward starting interest rate swaps. During the first nine months of 2004, we entered into eight forward starting interest rate swap transactions having an aggregate notional amount of $2 billion in anticipation of our financing activities associated with closing the GulfTerra Merger. Our purpose in entering into these transactions was to effectively hedge the underlying U.S. treasury rate related to our anticipated issuance of $2 billion in principal amount of fixed rate debt. On October 4, 2004, our Operating Partnership issued $2 billion of Rule 144A private placement debt securities under Senior Notes E, F, G and H. Each of the forward starting swaps was designated as a cash flow hedge under SFAS No. 133.

In April 2004, we elected to terminate the initial four forward starting swaps in order to manage and maximize the value of the swaps and to reduce future debt service costs. As a result, we received $104.5 million in cash from the counterparties. In September 2004, we settled the remaining four swaps resulting in an $85.1 million payment to the counterparties. The net gain of $19.4 million from these settlements will be amortized over the life of the associated debt as a reduction in Accumulated Other Comprehensive Income to interest expense.

The following table shows the notional amount covered by each forward starting swap and the cash gain (loss) associated with each upon settlement:

Term of Anticipated Debt Offering (or Forecasted Transaction)	**Notional Amount of Debt covered by Forward Starting Swaps**	**Net Cash Received upon Settlement of Forward Starting Swaps**
3-year, fixed rate debt instrument	$ 500,000	$ 4,613
5-year, fixed rate debt instrument	500,000	7,213
10-year, fixed rate debt instrument	650,000	10,677
30-year, fixed rate debt instrument	350,000	(3,098)
Total	$ 2,000,000	$ 19,405

Commodity risk hedging program

The prices of natural gas, NGLs, petrochemical products and MTBE 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 these risk management activities is to hedge our exposure to price risks associated with natural gas, NGL production and inventories, firm commitments and certain anticipated transactions.

We have adopted a policy to govern our use of commodity financial instruments to manage the risks of our natural gas and NGL businesses. The objective of this policy is to assist us in achieving our profitability goals while maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by Enterprise GP. We may enter into risk management transactions to manage price risk, basis risk, physical risk or other risks related to our commodity positions on both a short-term (less than 30 days) and long-term basis, not to exceed 24 months. Enterprise GP oversees the strategies associated with physical and financial risks (such as those mentioned previously), approves specific activities subject to the policy (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policy. At September 30, 2004, our portfolio consisted primarily of natural gas cash flow and fair value hedges.

13. BUSINESS SEGMENT INFORMATION

Business segments are components of a business about which separate financial information is available. These components are regularly evaluated by the CEO of our general partner 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.

As a result of the GulfTerra Merger (see Note 3), we have revised and renamed our reportable business segments, as discussed below. We have revised our prior segment information, to the extent practicable, in order to conform to the current business segment presentation.

We have segregated our business activities into four distinct 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 or process employed) and products produced and/or sold, as applicable.

The Offshore Pipelines & Services business segment consists of (i) approximately 1,000 miles of natural gas pipelines strategically located to serve production activities in some of the most active drilling and development regions in the Gulf of Mexico, (ii) ownership interests in four Gulf of Mexico offshore oil pipeline systems aggregating 419 miles and (iii) ownership interests in seven multi-purpose offshore hub platforms located in the Gulf of Mexico. In addition, this segment includes ownership interests in four relatively insignificant oil and natural gas producing properties located in the waters offshore of Louisiana.

The Onshore Natural Gas Pipelines & Services business segment includes natural gas pipeline systems aggregating an approximate 16,100 miles that provide for the gathering and transmission of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas. Included in this segment are two salt dome natural gas storage facilities located in Mississippi, which are strategically located to serve the Northeast, Mid-Atlantic and Southeast natural gas markets. We also lease a natural gas storage facility located in Texas.

The NGL Pipelines & Services business segment is comprised of (i) our natural gas processing business and related NGL marketing activities, (ii) NGL pipelines aggregating an approximate 11,730 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 our four propylene fractionation facilities, isomerization complex, and octane additive production facility. This segment also includes approximately 330 miles of various propylene pipeline systems and a 70-mile hi-purity isobutane pipeline.

The Other non-segment category is presented for financial reporting purposes only to show the historical equity earnings we received from GulfTerra GP and our underlying investment in this entity at December 31, 2003. We acquired a 50% membership interest in GulfTerra GP on December 15, 2003 in connection with Step One of the GulfTerra Merger (see Note 3). 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 segments. Therefore, we have segregated equity earnings from GulfTerra GP apart from our other investments to aid in comparability between the periods presented and future periods.

The following table shows the major components of each of our four new business segments along with a listing of the significant operating assets included within each component:

Name of Business Segment	Major Components of Each Business Segment and Principal Operating Assets included in Business Segment (*italicized*)
Offshore Pipelines & Services	Offshore natural gas pipelines: *Viosca Knoll Gathering System* *High Island Offshore System* *East Breaks, Falcon and Typhoon Systems* *Phoenix Gathering System* *Marco Polo - Gas Gathering System* *Manta Ray, Nautilus and Nemo Systems* Offshore oil pipelines: *Poseidon, Allegheny and Typhoon Systems* *Cameron Highway Oil Pipeline* *Marco Polo - Oil Pipeline* Offshore platform services: *Seven Gulf of Mexico platforms*
Onshore Natural Gas Pipelines & Services	Onshore natural gas pipelines (including associated gas treating plants): *San Juan Gathering System* *Permian Basin System* *Texas Intrastate System* *Acadian Gas System* Natural gas storage facilities in Texas, Louisiana and Mississippi
NGL Pipelines & Services	Natural gas processing plants and related marketing activities: *Two New Mexico plants (Chaco and Indian Basin)* *Nine South Texas processing plants* *Eleven Louisiana processing plants* *Pascagoula, Mississippi plant* *NGL marketing activities* NGL fractionation facilities: *Texas facilities (Mont Belvieu and South Texas plants)* *Louisiana facilities (Norco, Promix and BRF plants)* NGL pipelines and storage: *Mid-America and Seminole* *Dixie Pipeline* *Mont Belvieu, Texas NGL storage operations* *Import and Export facilities* *Other NGL pipeline and storage, including Lou-Tex NGL Pipeline and Louisiana NGL storage*
Petrochemical Services	Propylene fractionation facilities: *Texas facilities (Mont Belvieu)* *Louisiana facilities (BRPC)* *Various propylene pipelines, including Lou-Tex Propylene Pipeline* Isomerization facility located in Mont Belvieu, Texas Octane additive production facility located in Mont Belvieu, Texas

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: (1) depreciation, depletion and amortization expense; (2) operating lease expenses for which we do not have the payment obligation; (3) gains and losses on the sale of assets; and (4) selling, 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 is our use of the Dixie pipeline to transport propane sold to customers through our NGL marketing activities. See Note 8 for additional information regarding our related party relationships with unconsolidated affiliates.

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 service customers in a number of regions in the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are 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 non-GAAP segment gross operating margin for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	2003	2004	2003
Revenues (1)	$ 2,040,271	$ 1,234,780	$ 5,458,507	$ 3,927,025
Less: Operating costs and expenses (1)	(1,951,567)	(1,178,703)	(5,226,392)	(3,699,437)
Add: Equity in income (loss) of unconsolidated affiliates (1)	14,581	(18,040)	42,224	(16,647)
Depreciation and amortization in operating costs and expenses (2)	32,439	28,259	94,674	83,761
Retained lease expense, net in operating expenses allocable to us and minority interest (3)	2,273	2,273	6,820	6,820
Loss (gain) on sale of assets in operating costs and expenses (2)	43	(35)	158	(67)
Total non-GAAP gross operating margin	$ 138,040	$ 68,534	$ 375,991	$ 301,455

(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." That portion of the value contributed by a minority interest holder is a component of "Contributions from minority interests" as shown in the financing activities section of our Unaudited Condensed Statement of Consolidated Cash Flows.

A reconciliation of our measurement of total non-GAAP gross operating margin to GAAP consolidated 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) follows:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	2003	2004	2003
Total non-GAAP gross operating margin	$ 138,040	$ 68,534	$ 375,991	$ 301,455
Adjustments to reconcile total non-GAAP gross operating margin to GAAP operating income:				
Depreciation and amortization in operating costs and expenses	(32,439)	(28,259)	(94,674)	(83,761)
Retained lease expense, net in operating costs and expenses	(2,273)	(2,273)	(6,820)	(6,820)
Gain (loss) on sale of assets in operating costs and expenses	(43)	35	(158)	67
Selling, general and administrative costs	(10,076)	(7,415)	(26,629)	(28,939)
GAAP consolidated operating income	93,209	30,622	247,710	182,002
Other expense	(31,875)	(32,103)	(96,031)	(102,627)
GAAP income (loss) before provision for income taxes, minority interest and cumulative effect of changes in accounting principles	$ 61,334	$ (1,481)	$ 151,679	$ 79,375

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

	Business Segments						
	Offshore Pipelines & Services	**Onshore Nat. Gas Pipelines & Services**	**NGL Pipelines & Services**	**Petrochem. Services**	**Non-Segmt. Other**	**Adjustments and Eliminations**	**Consolidated Totals**
Revenues from third parties:							
Three months ended September 30, 2004		$ 77,432	$1,361,317	$ 363,197			$1,801,946
Three months ended September 30, 2003		29,656	838,136	176,252			1,044,044
Nine months ended September 30, 2004		285,206	3,599,905	976,971			4,862,082
Nine months ended September 30, 2003		271,599	2,654,307	558,228			3,484,134
Revenues from related parties:							
Three months ended September 30, 2004		84,891	151,002	2,432			238,325
Three months ended September 30, 2003		112,226	77,112	1,398			190,736
Nine months ended September 30, 2004		189,328	399,537	7,560			596,425
Nine months ended September 30, 2003		178,335	258,831	5,725			442,891
Intersegment and intrasegment revenues:							
Three months ended September 30, 2004		3,171	543,439	65,378		$ (611,988)	
Three months ended September 30, 2003		762	272,841	37,119		(310,722)	
Nine months ended September 30, 2004		6,508	1,312,481	185,195		(1,504,184)	
Nine months ended September 30, 2003		3,214	752,348	139,409		(894,971)	
Total revenues:							
Three months ended September 30, 2004		165,494	2,055,758	431,007		(611,988)	2,040,271
Three months ended September 30, 2003		142,644	1,188,089	214,769		(310,722)	1,234,780
Nine months ended September 30, 2004		481,042	5,311,923	1,169,726		(1,504,184)	5,458,507
Nine months ended September 30, 2003		453,148	3,665,486	703,362		(894,971)	3,927,025
Equity income (loss) in unconsolidated affiliates:							
Three months ended September 30, 2004	$ 720	158	2,699	245	$ 10,759		14,581
Three months ended September 30, 2003	1,648	108	1,384	(21,180)			(18,040)
Nine months ended September 30, 2004	2,576	314	6,349	960	32,025		42,224
Nine months ended September 30, 2003	5,420	144	5,450	(27,661)			(16,647)
Gross operating margin by individual business segment and in total:							
Three months ended September 30, 2004	720	7,186	83,851	35,524	10,759		138,040
Three months ended September 30, 2003	1,648	5,540	53,313	8,033			68,534
Nine months ended September 30, 2004	2,576	18,928	231,694	90,768	32,025		375,991
Nine months ended September 30, 2003	5,420	14,227	230,565	51,243			301,455
Segment assets:							
At September 30, 2004	660,245	3,836,575	2,689,926	456,300		80,655	7,723,701
At December 31, 2003		220,922	2,183,485	484,666		74,432	2,963,505
Investments in and advances to unconsolidated affiliates (see Note 6):							
At September 30, 2004	281,078	15,720	146,489	20,916			464,203
At December 31, 2003	127,605	2,519	190,682	22,006	424,947		767,759
Intangible Assets (see Note 7):							
At September 30, 2004	210,515	454,702	244,869	51,776			961,862
At December 31, 2003			215,072	53,821			268,893
Goodwill (see Note 7)							
At September 30, 2004	52,795	288,930	30,509	73,690			445,924
At December 31, 2003			8,737	73,690			82,427

Our completion of the GulfTerra Merger affected segment assets, investments in and advances to unconsolidated affiliates, intangible assets, goodwill and other accounts. For additional information regarding the merger-related transactions, see Note 3.

Revenues for the third quarter of 2004 increased $805.5 million over those recorded during the same period in 2003. The increase in revenues is primarily due to (i) higher revenues from our NGL and petrochemical marketing activities due to increased sales volumes and prices and (ii) the addition of revenues from our recently acquired South Texas midstream assets.

Our equity in the earnings of unconsolidated affiliates increased $32.6 million quarter-to-quarter. The equity earnings we recorded for the third quarter of 2003 were impacted by a $22.5 million non-cash asset impairment charge associated with our octane enhancement business. In addition, the third quarter of 2004 includes $10.8 million of equity earnings from GulfTerra GP, which we began consolidating on September 30, 2004 as a result of completing the GulfTerra Merger.

Revenues for the first nine months of 2004 increased $1.5 billion over those recorded during the first nine months of 2003. The increase in revenues is primarily due to (i) higher revenues from our NGL and petrochemical marketing activities due to increased sales volumes and prices and (ii) the addition of revenues from businesses acquired or consolidated since September 30, 2003, including BEF and our recently acquired South Texas midstream assets.

Our equity in the earnings of unconsolidated affiliates increased $58.9 million period-to-period. The equity earnings we recorded for the third quarter of 2003 were impacted by a $22.5 million non-cash asset impairment charge associated with our octane enhancement business. In addition, the first nine months of 2004 includes $32 million of equity earnings from GulfTerra GP, which we began consolidating on September 30, 2004 as a result of completing the GulfTerra Merger.

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 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”).

The non-distribution bearing Class A special units were included in the calculation of diluted earnings per unit prior to their conversion to common 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. See Note 9 for information regarding our performance-based restricted units issued in September 2004. 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 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.

Beginning in August 2003, we started reissuing treasury units to satisfy our obligations under EPCO unit option agreements. The reissuance of these treasury units to satisfy EPCO’s unit option liability has a dilutive effect on our earnings per unit. Prior to August 2003, EPCO had purchased practically all of the common units associated with its 1998 Plan in the open market. As a result, EPCO’s unit option plan did not have any effect on our fully diluted earnings per unit in prior periods.

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 September 30,		For the Nine Months Ended September 30,	
	2004	2003	2004	2003
Net income (loss)	$ 61,291	$ (3,261)	$ 152,907	$ 70,349
Less incentive earnings allocations to Enterprise GP	(6,853)	(5,096)	(19,435)	(13,659)
Net income (loss) available after incentive earnings allocation	54,438	(8,357)	133,472	56,690
Multiplied by Enterprise GP ownership interest (1)	2.0%	1.0%	2.0%	1.0%
Standard earnings (loss) allocation to Enterprise GP	$ 1,089	$ (84)	$ 2,669	$ 567
Incentive earnings allocation to Enterprise GP	$ 6,853	$ 5,096	$ 19,435	$ 13,659
Standard earnings (loss) allocation to Enterprise GP	1,089	(84)	2,669	567
Enterprise GP interest in net income (loss)	$ 7,942	$ 5,012	$ 22,104	$ 14,226

(1) Our general partner's ownership interest in us increased from 1% to 2% in December 2003 as a result of restructuring its overall ownership interest in us and our Operating Partnership

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 September 30,		For the Nine Months Ended September 30,	
	2004	2003	2004	2003
Income (loss) before change in accounting principle and Enterprise GP interest	$ 57,523	$ (3,261)	$142,126	$ 70,349
Cumulative effect of change in accounting principle	3,768		10,781	
Net income (loss)	61,291	(3,261)	152,907	70,349
Enterprise GP interest in net income (loss)	(7,942)	(5,012)	(22,104)	(14,226)
Limited partners' interest in net income (loss)	$ 53,349	$ (8,273)	$130,803	$ 56,123

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	2003	2004	2003
BASIC EARNINGS PER UNIT				
Numerator				
Income (loss) before changes in accounting principles and Enterprise GP interest	$ 57,523	$ (3,261)	$142,126	$ 70,349
Cumulative effect of changes in accounting principles	3,768		10,781	
Enterprise GP interest in net income (loss)	(7,942)	(5,012)	(22,104)	(14,226)
Limited partners' interest in net income (loss)	$ 53,349	$ (8,273)	$130,803	$ 56,123
Denominator				
Common units	247,861	200,587	229,286	174,057
Restricted common units	83		38	
Subordinated units		7,214		21,331
Class B special units	1,343		3,383	
Total	249,287	207,801	232,707	195,388
Basic earnings per unit				
Income (loss) per unit before changes in accounting principles and Enterprise GP interest	$ 0.23	$ (0.02)	$ 0.61	$ 0.36
Cumulative effect of changes in accounting principles	0.01		0.05	
Enterprise GP interest in net income (loss)	(0.03)	(0.02)	(0.10)	(0.07)
Limited partners' interest in net income (loss)	$ 0.21	$ (0.04)	$ 0.56	$ 0.29
DILUTED EARNINGS PER UNIT				
Numerator				
Income (loss) before changes in accounting principles and Enterprise GP interest	$ 57,523	$ (3,261)	$142,126	$ 70,349
Cumulative effect of changes in accounting principles	3,768		10,781	
Enterprise GP interest in net income (loss)	(7,942)	(5,012)	(22,104)	(14,226)
Limited partners' interest in net income (loss)	$ 53,349	$ (8,273)	$130,803	$ 56,123
Denominator				
Common units	247,861	200,587	229,286	174,057
Restricted common units	83		38	
Subordinated units		7,214		21,331
Class A special units				7,766
Class B special units	1,343		3,383	
Performance-based restricted units	1		*	
Series F2 convertible units	*		*	
Incremental option units	462		486	662
Total	249,750	207,801	233,193	203,816
Diluted earnings per unit				
Income (loss) per unit before changes in accounting principles and Enterprise GP interest	$ 0.23	$ (0.02)	$ 0.61	$ 0.35
Cumulative effect of changes in accounting principles	0.01		0.05	
Enterprise GP interest in net income (loss)	(0.03)	(0.02)	(0.10)	(0.07)
Limited partners' interest in net income (loss)	$ 0.21	$ (0.04)	$ 0.56	$ 0.28

* Amount is negligible.

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 the Operating Partnership. Our effective ownership of the Operating Partnership is 100%.

For the day of September 30, 2004 (the date we closed the GulfTerra Merger), GulfTerra and GulfTerra GP were temporarily subsidiaries of ours. On October 1, 2004, we contributed all of our ownership interests in these entities to the Operating Partnership. As a result of this contribution on the day following the GulfTerra Merger, GulfTerra and GulfTerra GP are now wholly-owned subsidiaries of our Operating Partnership.

At September 30, 2004, the Operating Partnership had $1.7 billion in outstanding publicly-traded debt securities represented by its Senior Notes A, B, C and D. On October 4, 2004, the Operating Partnership issued an additional $2 billion in principal amount of Rule 144A private placement debt securities represented by Senior Notes E, F, G and H. We act as guarantor of all of our Operating Partnership's consolidated debt obligations, with the exception of the Seminole Notes and any remaining amounts outstanding under GulfTerra's senior and senior subordinated notes after our Operating Partnership completed its tender offers in October 2004. 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 Notes 10 and 17.

Historically, the number and dollar amount of reconciling items between our consolidated financial statements and those of our Operating Partnership are insignificant. The differences between our statements and those of the Operating Partnership on September 30, 2004 are primarily the result of purchase accounting entries related to the GulfTerra Merger and intercompany debt balances between GulfTerra and the Operating Partnership. These reconciling items were eliminated the following day, October 1, 2004, when we contributed GulfTerra and GulfTerra GP to the Operating Partnership. Excluding the effects of this one day difference, the primary reconciling items between the Unaudited Condensed Consolidated Balance Sheet of the Operating Partnership and our Unaudited Condensed Consolidated Balance Sheet are the treasury units we own directly and minority interest. The differences in consolidated net income are primarily dividends recognized by the 1999 Trust (which are eliminated in consolidation) and minority interest.

The following tables show unaudited condensed financial information for the Operating Partnership for the periods and at the dates indicated:

Unaudited Condensed Consolidated Balance Sheets

	September 30, 2004	December 31, 2003
ASSETS		
Current assets	$ 3,216,950	$ 687,530
Property, plant and equipment, net	3,138,996	2,963,505
Investments in and advances to unconsolidated affiliates, net	292,106	767,759
Intangible assets, net	280,502	268,893
Goodwill	82,427	82,427
Deferred tax asset	7,265	10,437
Other assets	24,258	22,610
Total	$ 7,042,504	$ 4,803,161
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities	$ 1,608,253	$ 1,093,747
Long-term debt	3,918,244	1,899,548
Other liabilities	11,855	14,081
Minority interest	64,117	89,216
Partners' equity	1,440,035	1,706,569
Total	$ 7,042,504	$ 4,803,161
Total Operating Partnership debt obligations guaranteed by us	$ 4,499,000	$ 2,114,000

Unaudited Condensed Consolidated Statements of Operations

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	2003	2004	2003
Revenues	$2,040,271	$1,234,780	$5,458,507	$3,927,025
Costs and expenses	1,960,313	1,185,965	5,251,042	3,727,886
Equity in income (loss) of unconsolidated affiliates	16,706	(18,040)	42,213	(16,647)
Operating income	96,664	30,775	249,678	182,492
Other income (expense):				
Interest expense	(32,471)	(32,559)	(96,956)	(107,751)
Other, net	(1,392)	607	1,390	5,572
Total other income (expense)	(33,863)	(31,952)	(95,566)	(102,179)
Income (loss) before provision for taxes, minority interest and changes in accounting principles	62,801	(1,177)	154,112	80,313
Provision for taxes	(662)	(1,023)	(2,706)	(4,628)
Income (loss) before minority interest and changes in accounting principles	62,139	(2,200)	151,406	75,685
Minority interest	(3,152)	(808)	(6,800)	(3,767)
Income (loss) before changes in accounting principles	58,987	(3,008)	144,606	71,918
Cumulative effect of changes in accounting principles	3,768		10,781	
Net income (loss)	$ 62,755	$ (3,008)	$ 155,387	$ 71,918

16. COMMITMENTS AND CONTINGENCIES

Litigation

We are sometimes named as a defendant in litigation relating to our normal business operations. 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 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.

Environmental

Environmental costs for remediation are accrued at their undiscounted estimated amounts based on known remediation requirements. Such accruals are based on management's best estimate of the ultimate costs to remediate a given site and take into account the likely effects of inflation and other societal and economic factors, including estimated associated legal costs. We expense amounts for clean up of existing environmental contamination caused by past operations which do not benefit future periods. We expense or capitalize expenditures for ongoing compliance with environmental regulations that relate to past or current operations as appropriate. Environmental costs and related accruals were not significant to our historical financial statements prior to the GulfTerra Merger. GulfTerra has an environmental liability initially estimated at $21 million, which is included in other long-term liabilities on our Unaudited Condensed Consolidated Balance Sheet dated September 30, 2004, for remediation costs expected to be incurred over time associated with mercury gas meters.

While the outcome of our outstanding environmental matters cannot be predicted with certainty, based on the information known to date and our existing accruals, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, results of operations or cash flows. It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damage to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our current reserves are adequate.

Commitments under equity compensation plans of EPCO

In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense associated with certain employees who perform management, administrative and operating functions for us (see Note 8). This includes the costs associated with equity-based awards granted to these employees. At September 30, 2004, there were 2,558,000 options outstanding to purchase common units under EPCO's 1998 Plan that had been granted to employees for which we were responsible for reimbursing EPCO for the costs of such awards. The weighted-average strike price of the unit option awards was $18.53 per common unit. At September 30, 2004, 1,199,000 of these unit options were exercisable. An additional 50,000, 374,000, 25,000 and 910,000 of these unit options will be exercisable during the remainder of 2004 and in 2005, 2006 and 2008, respectively. As these options are exercised, we will reimburse EPCO in the form of a special cash distribution for the difference between the strike price paid by the employee and the actual price paid for the units awarded to the employee.

Joint Ventures

We conduct a portion of our activities through joint venture business arrangements formed to construct, operate and finance the development of our onshore and offshore midstream energy businesses. We are obligated to make our proportionate share of additional capital contributions to our joint ventures only to the extent that they are unable to satisfy their obligations from other sources including proceeds from credit arrangements. Examples of this type of business arrangement include our equity method investments in Cameron Highway, Deepwater Gateway and Poseidon, which were acquired as a result of the GulfTerra Merger.

Other commitments

Long-term debt-related commitments. We have long and short-term payment obligations under credit agreements such as our Senior Notes and revolving credit facilities. See Note 10 for a description of these debt obligations.

Operating lease commitments. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. There has been no material change in our operating lease commitments since December 31, 2003, except for those we assumed in connection with the GulfTerra Merger. The assumed commitments relate to three storage facilities located in Texas (one natural gas facility and two NGL facilities). The future minimum lease payments associated with the assumed operating lease commitments as of September 30, 2004 are as follows: $0.4 million, 2004; $7 million, 2005; $7 million, 2006; $5.8 million, 2007; $3.2 million, 2008; and $1.8 million thereafter.

EPCO contributed various equipment leases to us at our formation in 1998 for which EPCO has retained the cash payment obligations (the “retained leases”). EPCO has assigned to us the purchase options associated with the retained leases. We exercised our options to purchase an isomerization unit and related equipment during the first nine months of 2004 at a cost of $15 million. Should we decide to exercise all of the remaining purchase options associated with the other retained leases (which are also at fair value), an additional $2.8 million would be payable in 2004, $2.3 million in 2008 and $3.1 million in 2016.

Purchase obligations. We define purchase obligations as agreements to purchase goods or services that are enforceable and legally binding (unconditional) and that specify all significant terms, including (i) fixed or minimum quantities to be purchased; (ii) fixed, minimum or variable pricing provisions; and (iii) the approximate timing of the purchase transactions. Historically, our purchase obligations have resulted primarily from product purchase commitments and to a lesser extent from service contract commitments and capital expenditure commitments. There has been no material change in our product purchase and service contract commitments since December 31, 2003. GulfTerra’s operations are primarily that of a pipeline transportation service provider; therefore, its purchase obligations have been minimal when compared to our forecasted amounts. Our estimated capital expenditures commitments increased to $62 million at September 30, 2004 primarily due to the projects we assumed as a result of the GulfTerra Merger.

17. SUBSEQUENT EVENTS

Contribution of GulfTerra and GulfTerra GP to our Operating Partnership

On October 1, 2004, we contributed all of our ownership interests in GulfTerra and GulfTerra GP to our Operating Partnership. As a result of this contribution, GulfTerra and GulfTerra GP are now wholly-owned subsidiaries of our Operating Partnership.

October 2004 Senior Notes offering (see Note 10)

On October 4, 2004, our Operating Partnership issued $2 billion of senior unsecured notes in a Rule 144A private placement offering. The interest rate, principal amount and net proceeds, before expenses, for each senior note in this offering are shown in the following table:

Senior Note Issued	Fixed Interest Rate	Principal Amount	Bond Discount	Proceeds to Us, Before Expenses
Senior Notes E, due October 2007	4.000%	$ 500,000	$ 2,140	$ 497,860
Senior Notes F, due October 2009	4.625%	500,000	4,405	495,595
Senior Notes G, due October 2014	5.600%	650,000	4,784	645,216
Senior Notes H, due October 2034	6.650%	350,000	4,203	345,797
Totals		$ 2,000,000	$ 15,532	$ 1,984,468

The net proceeds from this offering were used to reduce debt amounts outstanding under the Operating Partnership's $2.25 billion 364-Day Acquisition Revolving Credit Facility that was used to partially fund the GulfTerra Merger on September 30, 2004.

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.

Tender offer for GulfTerra senior subordinated and senior notes (see Note 10)

On October 4, 2004, all of the cash tender offers made by our Operating Partnership for any and all of GulfTerra's outstanding senior subordinated and senior notes expired. As of the expiration time, our Operating Partnership had received tenders of senior subordinated and senior notes aggregating $915 million, or 99.3% of the notes outstanding. On October 5, 2004, our Operating Partnership purchased the notes for a total price of approximately $1.1 billion. The following table shows the four GulfTerra senior debt obligations affected, including the principal amount of each series of notes tendered, as well as the payment made by Enterprise to complete the tender offers.

Description	Principal Amount Tendered	Cash payments made by Enterprise: Accrued Interest	Tender Price (1)	Total Price
8.50% Senior Subordinated Notes due 2010 (Represents 98.2% of principal amount outstanding)	$ 212,057	$ 6,209	$ 246,366	$ 252,575
10.625% Senior Subordinated Notes due 2012 (Represents 99.9% of principal amount outstanding)	133,916	4,901	167,612	172,513
8.50% Senior Subordinated Notes due 2011 (Represents 99.5% of principal amount outstanding)	319,823	9,364	359,379	368,743
6.25% Senior Notes due 2010 (Represents 99.7% of principal amount outstanding)	249,250	5,366	274,073	279,439
Totals	$ 915,046	$ 25,840	$ 1,047,430	$ 1,073,270

(1) Tender price includes consent payment of $30 per $1,000 principal amount tendered.

Conversions of Series F2 convertible units

On October 29, 2004, 60 of the 80 outstanding Series F2 convertible units were converted into 1,458,434 Enterprise common units. As a result of this conversion, we received a payment of $30 million from the holder of the Series F2 convertible units (representing a conversion price of $20.57 per Enterprise common unit). Net proceeds from this conversion, including Enterprise GP's proportionate capital contribution of $0.6 million, were $29.7 million after deducting transaction costs of $0.9 million.

On November 8, 2004, the remaining 20 outstanding Series F2 convertible units were converted into 491,883 Enterprise common units. As a result of this conversion, we received a payment of $10 million from the holder of the Series F2 convertible units (representing a conversion price of $20.33 per Enterprise common unit). Net proceeds from this conversion, including Enterprise GP's proportionate capital contribution of $0.2 million, were $9.9 million after deducting transaction costs of $0.3 million.

Issuance of common units in November 2004 in connection with DRIP

On November 8, 2004, we issued approximately 2.2 million common units in connection with our DRIP, which generated net proceeds of $49.3 million (including our general partner's proportionate net capital contribution of approximately $1 million). We expect to use these proceeds for general partnership purposes.

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

For the three and nine months ended September 30, 2004 and 2003.

INTRODUCTION

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership listed on the NYSE under the ticker symbol "EPD." Unless the context requires otherwise, references to "we," "us," "our" or "Enterprise" are intended to mean the consolidated business and operations of Enterprise Products Partners L.P. Certain abbreviated entity names and other capitalized and industry terms are defined within the glossary of this quarterly report on Form 10-Q.

We were formed in April 1998 to own and operate certain NGL-related businesses of EPCO, Inc. ("EPCO," formerly Enterprise Products Company). We conduct substantially all of our business through wholly- owned subsidiaries, Enterprise Products Operating L.P. (our "Operating Partnership") and GulfTerra Energy Partners, L.P. ("GulfTerra"). On September 30, 2004, we completed the GulfTerra Merger and related transactions. We are owned 98% by our limited partners and 2% by our general partner ("Enterprise GP"). We and our general partner are also affiliates of EPCO.

The following discussion and analysis should be read in conjunction with our unaudited condensed consolidated financial statements and notes included under Item 1 of this quarterly report. Other risks involved in our business are discussed under "*Quantitative and Qualitative Disclosures about Market Risk*" included under Item 3 of this quarterly report.

Cautionary Statement regarding Forward-Looking Information

This quarterly report contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "goal," "forecast," "intend," "could," "believe," "may" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions. 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

Among the key risk factors that may have a direct bearing 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 our debt level on our future financial and operating flexibility;
- a reduction in demand for our products by the petrochemical, refining or heating industries;
- a decline in the volume of natural gas, NGLs and crude oil delivered to our facilities;
- competition from third parties in the midstream energy business;
- the failure to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for qualified assets;
- the timing of operating cash flows from our capital projects may not be immediate;
- an increase in actual construction, development and acquisition costs over our forecasted amounts;
- an inability to cause our joint ventures to take or not to take certain actions unless some or all of our joint venture participants agree;

- federal, state or regulatory measures may impose significant costs and liabilities on our operations;
- the failure of our credit risk management efforts to adequately protect us against customer non-payment;
- terrorist attacks affecting our facilities;
- natural disasters, catastrophes or other events resulting in personal injury, property damage and environmental damage could curtail our operations and adversely affect our cash flow;
- significant costs and liabilities resulting from our pipeline integrity program;
- the failure to successfully integrate our operations with GulfTerra's or any other companies we acquire; and
- the failure to realize the anticipated cost savings, synergies and other benefits of the GulfTerra Merger.

We have no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

RECENT DEVELOPMENTS

Completion of the GulfTerra Merger

General

On September 30, 2004, Enterprise and GulfTerra completed the merger of GulfTerra with a wholly-owned subsidiary of Enterprise, with GulfTerra being the surviving entity thereof. Additionally, Enterprise completed certain other transactions related to the merger, including receipt of Enterprise GP's contribution of a 50% membership interest in GulfTerra GP, which was acquired by Enterprise GP from El Paso, and the purchase of certain midstream energy assets located in South Texas from El Paso. The aggregate value of the total consideration Enterprise paid or issued to complete the GulfTerra Merger was approximately $4 billion.

As a result of the GulfTerra Merger, GulfTerra and GulfTerra GP became wholly-owned subsidiaries of Enterprise on September 30, 2004. On October 1, 2004, we contributed our ownership interests in GulfTerra and GulfTerra GP to our Operating Partnership, which resulted in GulfTerra and GulfTerra GP becoming wholly-owned subsidiaries of the Operating Partnership.

Overview of the GulfTerra and South Texas midstream assets

GulfTerra owns or has interests in natural gas pipeline systems extending over 15,650 miles. These pipeline systems include natural gas gathering systems located onshore in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas and offshore in active drilling and development regions in the Gulf of Mexico. GulfTerra also owns interests in five natural gas processing and treating plants in New Mexico, Texas and Colorado.

In addition, GulfTerra has interests in seven multi-purpose offshore hub platforms in the Gulf of Mexico, including the recently completed Marco Polo TLP. These platforms were specifically designed to be used as deepwater hubs and production handling and pipeline maintenance facilities. Many of GulfTerra's offshore natural gas and oil pipelines utilize these platforms.

GulfTerra also owns two salt dome natural gas storage facilities in Mississippi that are connected to five interstate pipeline systems, have a combined current working capacity of 13.5 Bcf and are capable of delivering in excess of 1.2 Bcf/d of natural gas. In addition, GulfTerra has the exclusive right to use a natural gas storage facility in South Texas under an operating lease that expires in January 2008. This facility has a working gas capacity of 6.4 Bcf and a maximum withdrawal capacity of 0.8 Bcf/d of natural gas.

In addition, GulfTerra owns interests in four offshore crude oil pipeline systems, which extend over 380 miles, and recently completed construction of the 390-mile Cameron Highway Oil Pipeline. GulfTerra also owns over 1,000 miles of intrastate NGL pipelines and four NGL fractionation plants in Texas; a 3.3 MMBbl propane storage facility in Mississippi; and, owns or leases NGL storage facilities in Louisiana and Texas with aggregate capacity of approximately 21.3 MMBbls. GulfTerra also owns interests in four relatively insignificant oil and natural gas producing properties located in the Gulf of Mexico offshore Louisiana.

The South Texas midstream assets consist of nine natural gas processing plants with a combined capacity of 1.9 Bcf/d, a 294-mile natural gas gathering system, a natural gas treating facility with a capacity of 150 MMcf/d and a small NGL pipeline.

The GulfTerra Merger transactions

The GulfTerra Merger occurred in several interrelated transactions as described below.

- *Step One*. On December 15, 2003, Enterprise purchased a 50% membership interest in GulfTerra GP from El Paso for $425 million in cash. GulfTerra GP owns a 1% general partner interest in GulfTerra. Prior to completion of the GulfTerra Merger, Enterprise accounted for its investment in GulfTerra GP using the equity method of accounting. The $425 million in funds required to complete Step One were borrowed under an Interim Term Loan and our pre-merger revolving credit facilities. This amount was fully repaid with the net proceeds from equity offerings completed during the first nine months of 2004. See Note 10 for additional information regarding changes in our debt obligations since December 31, 2003.

- *Step Two*. On September 30, 2004, the GulfTerra Merger was consummated and GulfTerra and GulfTerra GP became wholly-owned subsidiaries of Enterprise. The GulfTerra Merger was accounted for using purchase accounting. Step Two of the GulfTerra Merger included the following transactions:

  - Immediately prior to closing the GulfTerra Merger, Enterprise GP acquired El Paso's remaining 50% membership interest in GulfTerra GP for $370 million in cash paid to El Paso and the issuance of a 9.9% membership interest in Enterprise GP to El Paso. Subsequently, Enterprise GP contributed this 50% membership interest in GulfTerra GP to us without the receipt of additional general partner interest, common units or other consideration. Enterprise GP borrowed the foregoing $370 million from Dan Duncan LLC (which owns a 4.505% membership interest in Enterprise GP), which obtained the funds from a loan from EPCO (which indirectly owns a 85.595% membership interest in Enterprise GP).

  - Immediately prior to closing the GulfTerra Merger, Enterprise paid $500 million in cash to El Paso for 10,937,500 Series C units of GulfTerra and 2,876,620 common units of GulfTerra. The remaining 57,762,369 GulfTerra common units (7,433,425 of which were owned by El Paso) were converted into 104,549,823 Enterprise common units (13,454,499 of which are held by El Paso) at the time of the consummation of the GulfTerra Merger.

- *Step Three*. Immediately after Step Two was completed, Enterprise acquired certain South Texas midstream assets from El Paso for $155.3 million in cash, which was effective September 1, 2004 and is subject to post-closing adjustments.

In connection with the closing of the GulfTerra Merger, on September 30, 2004, our Operating Partnership borrowed an aggregate $2.8 billion under its new revolving credit facilities in order to fund its cash payment obligations under Step Two and Step Three of the GulfTerra Merger and related transactions, including the tender offers for GulfTerra's outstanding senior and senior subordinated notes. For additional information regarding the GulfTerra Merger, please see Note 3 of the Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report.

The GulfTerra Merger is expected to have the following significant benefits:

- The GulfTerra Merger further expands our integrated natural gas and NGL transportation, fractionation, processing, storage and import/export network in North America. The operations of the combined company will be strategically located to serve the major supply basins for NGL-rich natural gas, the major NGL storage hubs in North America and international markets. We believe that the combined company's location in these markets will provide better access to natural gas, NGL and petrochemical supply volumes, anticipated demand growth and business expansion opportunities. The geographic presence of the combined company will be strengthened in areas where we historically had no significant operations, such as the San Juan and Permian Basins.

- We expect that the diversified asset portfolio of the combined company will provide operating income from a broader range of sources than our current operations. Additionally, GulfTerra's operations currently benefit from higher natural gas prices and will provide a natural hedge to our NGL business, which generally benefits from stable or lower natural gas prices.

- Both we and GulfTerra have long-term relationships with many of our suppliers and customers, and we believe that the combined company will continue to benefit from these relationships. The combined company will jointly own facilities with many of its customers who will either provide raw materials to or consume the end products from the combined company's facilities.

- We believe that the combined company's operating costs, particularly for its large-scale facilities, will be competitive with or lower than those associated with the combined company's competitors. We expect that the combined company's annual operating costs will be lower than our and GulfTerra's aggregate historical costs and expect that the combined company will achieve annual interest expense savings through its strategy for management of its debt obligations.

- We believe that GulfTerra has significant development opportunities, and that the combination of our operations and GulfTerra's operations will provide the combined company with incremental growth opportunities for both onshore and offshore projects. Many of the combined company's assets will have additional capacity that can accommodate increased volumes at low incremental cost.

- We believe that over the long term the combined company will have a lower cost of capital than many of its competitors, which will enable it to compete more effectively in acquiring assets and expanding its systems.

Both we and GulfTerra have historically operated our largest natural gas processing and fractionation facilities and most of our pipelines. As the leading provider of NGL-related services, we have established a reputation in the industry as a reliable and cost-effective operator. After the closing of the GulfTerra Merger, affiliates of Dan L. Duncan, our co-founder and the chairman of Enterprise Parent's general partner, own a 90.1% membership interest in Enterprise GP, and El Paso owns a 9.9% membership interest in Enterprise GP. In addition, after giving effect to the GulfTerra Merger, Mr. Duncan and his affiliates collectively own an approximate 34.4% limited partner interest in Enterprise. The persons that serve as executive officers of the combined company average more than 31 years of industry experience.

Divestitures associated with the GulfTerra Merger

In order to complete the GulfTerra Merger, we are required under a consent decree published for comment by the FTC on September 30, 2004, to sell (i) our 50% interest in Starfish, which in turn owns a 50% interest in the Stingray natural gas pipeline and related gathering pipelines and dehydration and other facilities located in south Louisiana and the Gulf of Mexico offshore Louisiana by March 31, 2005 and (ii) our undivided 50% interest in a Mississippi propane storage facility by December 31, 2004.

Amendments to natural gas processing agreements

During the first quarter of 2004, we completed a program to convert essentially all of our traditional keepwhole contracts to other types of processing arrangements where the producer assumes all or most of the direct commodity price risk between NGLs and natural gas. These new arrangements include simple fee-based contracts, hybrid fee-based contracts with margin-sharing provisions and percent-of-liquids agreements. We began this effort in 2003. Prior to starting this effort, approximately 70% of the natural gas we processed was under traditional keepwhole arrangements. Under these arrangements, the volatility in natural gas prices since 2000 created large swings in the operating results of our natural gas processing business, which in turn did not provide us with a consistent return on our investment.

As a result of this effort, approximately 63% of the 2 Bcf/d of natural gas we processed during the second and third quarters of 2004 was under processing agreements containing a fee-based component. This compares to approximately 100 MMcf/d of fee-based volumes prior to amending these agreements. The remaining 750 MMcf/d, or 0.75 Bcf/d, was processed primarily under percent-of-liquids agreements compared to 0.5 Bcf/d under such arrangements previously. The new percent-of-liquids agreements resulted in approximately 1 MBPD of additional equity NGL production during the second and third quarters of 2004.

To provide us with the opportunity to earn additional gross operating margin above that provided by fee-based and percent-of-liquids arrangements and to align our interest with certain producers, some of our contracts provide a mechanism for us to participate in margin-sharing arrangements with the producer (in addition to the fee-based component we would earn) without exposing us to the risk of incremental cash losses. Approximately 50% of the natural gas we expect to process during 2004 is pursuant to these margin-sharing arrangements.

We believe these contract revisions will result in our being fairly compensated for this critical midstream service while providing producers with the assurance that their processing agreements with us are operative regardless of the natural gas price. We also believe that these new agreements will (1) provide us with a more consistent base of revenue and gross operating margin from our natural gas processing business, (2) greatly reduce the direct commodity price risk that previously existed under traditional keepwhole arrangements and (3) provide for a more reliable return on our investment.

Equity offerings

In May 2004, we sold 17,250,000 common units to the public at an offering price of $21.00 per unit. Net proceeds from this offering, including Enterprise GP’s proportionate net capital contribution of $7.1 million, were $353.1 million after deducting applicable underwriting discounts, commissions and offering expenses of $16.3 million. The net proceeds from this offering, including Enterprise GP’s proportionate net capital contribution, were used to repay in full our $225 million Interim Term Loan and to temporarily reduce borrowings under our pre-merger revolving credit facilities.

In August 2004, we sold 17,250,000 common units to the public at an offering price of $20.20 per unit. Net proceeds from this offering, including Enterprise GP’s proportionate net capital contribution of $6.8 million, were approximately $341.2 million after deducting applicable underwriting discounts, commissions and offering expenses of $13.9 million. The net proceeds from this offering, including Enterprise GP’s proportionate net capital contribution were used to fund a portion of the purchase price of Steps Two and Three of the GulfTerra Merger transactions and to temporarily reduce borrowings under our pre-merger Multi-Year Revolving Credit Facility “A”.

We have also issued common units in connection with our distribution reinvestment plan, Series F2 convertible units and related programs. For additional information regarding our active registration statements, please read “*Liquidity and Capital Resources*.”

October 2004 Senior Notes offering

On October 4, 2004, our Operating Partnership issued $2 billion of senior unsecured notes in a Rule 144A private placement offering. For additional information regarding this debt, please read our “*Liquidity and Capital Resources – Our debt obligations*.”

Tender offer for GulfTerra senior subordinated and senior notes

On October 5, 2004, our Operating Partnership completed its cash tender offers for any and all of GulfTerra's outstanding senior subordinated and senior notes. As of the expiration time, our Operating Partnership had received tenders of senior subordinated and senior notes aggregating $915 million, or 99.3% of the notes outstanding. For additional information regarding the tender offers, please read our "*Liquidity and Capital Resources – Our debt obligations*."

OUR RESULTS OF OPERATIONS

Since the GulfTerra Merger closed during the day on September 30, 2004, our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income do not include any earnings from GulfTerra due to the immateriality of the amounts. The effective closing date of our purchase of the South Texas midstream assets was September 1, 2004. As a result, our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income for the three and nine months ended September 30, 2004 includes one month of results of operations from the South Texas midstream assets.

As a result of the GulfTerra Merger, we have revised and renamed our reportable business segments, as discussed below. We have revised our prior segment information, to the extent practicable, in order to conform to the current business segment presentation.

We have segregated our business activities into four distinct 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 or process employed) and products produced and/or sold, as applicable. For a listing of the major components of each of our four new business segments and the principal operating assets included within each of the major components, please see Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

The **Offshore Pipelines & Services** business segment consists of (i) approximately 1,000 miles of natural gas pipelines strategically located to serve production activities in some of the most active drilling and development regions in the Gulf of Mexico, (ii) ownership interests in four Gulf of Mexico offshore oil pipeline systems aggregating 419 miles and (iii) ownership interests in seven multi-purpose offshore hub platforms located in the Gulf of Mexico. In addition, this segment includes ownership interests in four relatively insignificant oil and natural gas producing properties located in the waters offshore of Louisiana.

The **Onshore Natural Gas Pipelines & Services** business segment includes natural gas pipeline systems aggregating an approximate 16,100 miles that provide for the gathering and transmission of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas. Included in this segment are two salt dome natural gas storage facilities located in Mississippi, which are strategically located to serve the Northeast, Mid-Atlantic and Southeast natural gas markets. We also lease a natural gas storage facility located in Texas.

The **NGL Pipelines & Services** business segment is comprised of (i) our natural gas processing business and related NGL marketing activities, (ii) NGL pipelines aggregating an approximate 11,730 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 our four propylene fractionation facilities, isomerization complex, and octane additive production facility. This segment also includes approximately 330 miles of various propylene pipeline systems and a 70-mile hi-purity isobutane pipeline.

The Other non-segment category is presented for financial reporting purposes only to show the historical equity earnings we received from GulfTerra GP and our underlying investment in this entity at December 31, 2003. 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 segments. Therefore, we have segregated equity earnings from GulfTerra GP apart from our other investments to aid in comparability between the periods presented and future periods.

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: (1) depreciation, depletion and amortization expense; (2) operating lease expenses for which we do not have the payment obligation; (3) gains and losses on the sale of assets; and (4) selling, 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 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 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 our Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Our gross operating margin amounts were as follows for the periods indicated:

	For the Three Months Ended September 30,		**For the Nine Months Ended September 30,**	
	2004	**2003**	**2004**	**2003**
Gross operating margin by segment:				
Offshore Pipelines & Services	$ 720	$ 1,648	$ 2,576	$ 5,420
Onshore Natural Gas Pipelines & Services	7,186	5,540	18,928	14,227
NGL Pipelines & Services	83,851	53,313	231,694	230,565
Petrochemical Services	35,524	8,033	90,768	51,243
Other, non-segment	10,759		32,025	
Total gross operating margin	$138,040	$ 68,534	$375,991	$301,455

For a reconciliation of non-GAAP gross operating margin to GAAP operating income, please read “Other Items” included within this Item 2.

The following table illustrates selected average quarterly industry index prices for natural gas, crude oil, selected NGL and petrochemical products and indicative gas processing gross spreads since the beginning of 2003:

	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	Indicative Gas Processing Gross Spread, $/gallon
	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(3)
2003										
1st Quarter	$6.58	$34.12	$0.43	$0.65	$0.76	$0.80	$0.85	$0.24	$0.21	$0.05
2nd Quarter	$5.40	$29.04	$0.39	$0.53	$0.58	$0.62	$0.65	$0.25	$0.19	$0.04
3rd Quarter	$4.97	$30.21	$0.37	$0.56	$0.67	$0.68	$0.73	$0.21	$0.15	$0.10
4th Quarter	$4.58	$31.18	$0.40	$0.58	$0.73	$0.71	$0.75	$0.22	$0.16	$0.17
Average for Year	$5.38	$31.14	$0.40	$0.58	$0.68	$0.70	$0.74	$0.23	$0.18	$0.09
2004										
1st Quarter	$5.69	$35.25	$0.43	$0.66	$0.76	$0.76	$0.87	$0.29	$0.26	$0.13
2nd Quarter	$6.00	$38.34	$0.45	$0.65	$0.79	$0.79	$0.92	$0.32	$0.26	$0.12
3rd Quarter	$5.75	$43.90	$0.52	$0.79	$0.92	$0.92	$1.05	$0.32	$0.27	$0.26
Average for Year	$5.81	$39.16	$0.47	$0.70	$0.82	$0.82	$0.95	$0.31	$0.26	$0.17

(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.

(3) The Indicative Gas Processing Gross Spread is a relative measure used by the NGL industry as an indicator of the gross economic benefit derived from extracting NGLs from natural gas production on the U.S. Gulf Coast. Specifically, it is the amount by which the economic value of a composite gallon of NGLs exceeds the value of the equivalent amount of energy of natural gas based on NGL and natural gas prices on the U.S. Gulf Coast. It is assumed that a gallon of NGLs is comprised of 33% ethane, 32% propane, 11% normal butane, 8% isobutane and 16% natural gasoline. The value of a composite gallon of NGLs is determined by multiplying these component percentages by industry index prices listed in the table above. The value of the equivalent amount of energy of natural gas to one gallon of NGLs is 8.9% of the price of a MMBtu of natural gas. The Indicative Gas Processing Gross Spread does not consider the operating and fuel costs incurred by a natural gas processing plant to extract the NGLs nor the transportation and fractionation costs to deliver the NGLs and natural gas to market.

Our significant pipeline throughput, plant production and processing volumetric data were as follows for the periods indicated (on a net basis, taking into account our ownership interests):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	2003	2004	2003
Offshore Pipelines & Services, net:				
Natural gas transportation volumes (MMBtu/d)	393	438	423	451
Onshore Natural Gas Pipelines & Services, net:				
Natural gas transportation volumes (MMBtu/d)	685	619	650	590
NGL Pipelines & Services, net:				
NGL transportation volumes (MBPD)	1,450	1,323	1,358	1,273
NGL fractionation volumes (MBPD)	239	233	235	223
Equity NGL production (MBPD)	47	41	47	42
Fee-based natural gas processing (MMcf/d)	1,217	224	944	150
Petrochemical Services, net:				
Butane isomerization volumes (MBPD)	82	77	73	80
Propylene fractionation volumes (MBPD)	58	54	58	57
Octane additive production volumes (MBPD)	12	4	9	4
Petrochemical transportation volumes (MBPD)	76	77	73	63
Total, net:				
NGL and petrochemical transportation volumes (MBPD)	1,527	1,400	1,430	1,336
Natural gas transportation volumes (MMBtu/d)	1,079	1,058	1,074	1,042
Equivalent transportation volumes (MBPD) (1)	1,811	1,678	1,713	1,610

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

The following table summarizes our consolidated revenues, costs and expenses, equity in income of unconsolidated affiliates and operating income for the periods indicated (dollars in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	2003	2004	2003
Revenues	$ 2,040,271	$ 1,234,780	$ 5,458,507	$ 3,927,025
Operating costs and expenses	1,951,567	1,178,703	5,226,392	3,699,437
Selling, general and administrative costs	10,076	7,415	26,629	28,939
Equity in income (loss) of unconsolidated affiliates	14,581	(18,040)	42,224	(16,647)
Operating income	93,209	30,622	247,710	182,002

General business environment

The strength of the domestic and global economic recoveries continues to drive increased demand for all forms of energy despite higher commodity prices. Our largest NGL consuming customers in the ethylene industry have seen strong demand for their products, which has enabled them to raise prices to mitigate higher fuel and feedstock costs. With the unusually high price of crude oil relative to natural gas, ethane and propane are the preferred feedstocks of the ethylene industry. For the third quarter of 2004, ethane demand by the ethylene industry increased by 22% from the third quarter of 2003 to 809 MBPD and propane demand increased by 23% to 350 MBPD. Early indications are that ethane and propane demand during the fourth quarter of 2004 will also be higher than during the same period in 2003. Even with the ethylene industry currently producing at an annual rate of 58 billion pounds per year, we have not seen a build-up of inventory in either ethane or ethylene supply chains. Our customers are expecting high utilization rates throughout the fourth quarter of 2004 and into 2005. As a result of this strong demand for NGLs, most of our pipelines, fractionators and processing plants realized an increase in volumes.

The effects of Hurricane Ivan, however, have reduced volumes delivered to our facilities in Mississippi and eastern Louisiana since the middle of September 2004. We estimate that this reduction in volumes resulted in a $7 million decrease in gross operating margin for the third quarter of 2004 from what we had expected prior to the storm. We expect that the effects of the hurricane will reduce our previous estimates of gross operating margin for the fourth quarter of 2004 by approximately $18 million. These amounts are prior to any potential reimbursements we may receive from coverage provided by insurance.

As a result of the GulfTerra Merger, we significantly increased our midstream assets located in the Gulf of Mexico. We have several projects that have either recently started operations or are scheduled to become operational soon. Among these are the Marco Polo and Phoenix deepwater projects (began operations during third quarter of 2003), the Front Runner oil pipeline (operations to begin during fourth quarter of 2004) and the Cameron Highway oil pipeline system (started line fill in October 2004). For additional information regarding these projects and our other capital spending, please read "*Our Liquidity and Capital Resources – Capital* Spending."

At our Mont Belvieu complex, our NGL fractionators processed on a net basis an average of 139 MBPD during the third quarter of 2004 compared to 133 MBPD during the second quarter of 2004. In October 2004, we started receiving 63 MBPD of new mixed NGL volumes from William's Rocky Mountain production. Since that time, we have been running at near full capacity and have recently approved a fractionation expansion project that should provide energy efficiencies and increase our capacity at this facility by 15 MBPD.

As a result of global events, we expect that the unusual level of volatility in crude oil, natural gas and NGL prices will continue. The volatility in hydrocarbon prices impacts the prices we charge customers for products and services and those we pay vendors for feedstocks, fuel and other purchases.

Historical Enterprise

Three months ended September 30, 2004 compared to three months ended September 30, 2003

Revenues for the third quarter of 2004 increased $805.5 million over those recorded during the same period in 2003. The increase in revenues is primarily due to (i) higher revenues from our NGL and petrochemical marketing activities due to increased sales volumes and prices and (ii) the addition of revenues from our recently acquired South Texas midstream assets.

Costs and expenses increased $775.5 million quarter-to-quarter primarily due to (i) higher product prices and volumes which resulted in an increase in the cost of sales of our NGL and petrochemical marketing activities and (ii) the addition of costs and expenses attributable to our recently acquired South Texas midstream assets. The weighted-average NGL price was 77 CPG for the third quarter of 2004 compared to 54 CPG for the third quarter of 2003.

Our equity in the earnings of unconsolidated affiliates increased $32.6 million quarter-to-quarter. The equity earnings we recorded for the third quarter of 2003 were impacted by a $22.5 million non-cash asset impairment charge associated with our octane enhancement business. In addition, the third quarter of 2004 includes $10.8 million of equity earnings from GulfTerra GP, which we began consolidating on September 30, 2004 as a result of completing the GulfTerra Merger.

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

Offshore Pipelines & Services. Gross operating margin from our Offshore Pipelines & Services segment was $0.7 million for the third quarter of 2004 compared to $1.6 million for the third quarter of 2003. Overall, natural gas throughput volumes were 393 MMBtu/d for the third quarter of 2004 versus 438 MMBtu/d for the same period during 2003. Equity earnings from our Neptune natural gas pipeline investment decreased $0.9 million quarter-to-quarter primarily due to a decrease in volumes from the Brutus and Hickory fields and natural depletion of production fields served by this system.

Onshore Natural Gas Pipelines & Services. Gross operating margin from our Onshore Natural Gas Pipelines & Services segment was $7.2 million for the third quarter of 2004 compared to $5.5 million for the third quarter of 2003. The $1.7 million increase in segment gross operating margin is attributable to higher natural gas prices quarter-to-quarter, which resulted in increased natural gas sales margins for our Acadian subsidiary. Overall, natural gas pipeline throughput volumes were 685 MMBtu/d during the third quarter of 2004 versus 619 MMBtu/d during the same period in 2003. Natural gas prices averaged $5.75 per MMBtu during the third quarter of 2004 compared to $4.97 per MMBtu during the third quarter of 2003.

NGL Pipelines & Services. Gross operating margin from our NGL Pipelines & Services segment was $83.9 million for the third quarter of 2004 compared to $53.3 million for the same period in 2003. Gross operating margin from natural gas processing increased $19.7 million quarter-to-quarter primarily due to improved processing economics in the 2004 period and the addition of $7.8 million of gross operating margin for the month of September 2004 from our newly acquired South Texas midstream assets. Indicative gas processing gross spreads on the U.S. Gulf Coast averaged 26 CPG during the third quarter of 2004 and 10 CPG during the third quarter of 2003, which resulted in an increase in the amount of NGLs extracted. Equity NGL production was 47 MBPD for the third quarter of 2004 compared to 41 MBPD for the third quarter of 2003. Natural gas processing volumes under contracts with fee-based components increased to 1,217 MMcf/d in the third quarter of 2004 from 224 MMcf/d in the third quarter of 2003 reflecting amendments to our natural gas processing contract mix.

Gross operating margin from NGL pipelines increased $3.8 million quarter-to-quarter primarily due to improved results from our Mid-America and Seminole pipelines. Net overall NGL transportation volumes were 1,450 MBPD for the third quarter of 2004 versus 1,323 MBPD during the same period in 2003. Of the 127 MBPD increase in pipeline throughput rates, 120 MBPD of the increase is attributable to Mid-America and Seminole, which experienced stronger demand for services during the 2004 period. Results for the third quarter of 2004 also included a $4 million non-cash asset impairment charge associated with our Hattiesburg, Mississippi NGL storage facility.

Gross operating margin from NGL fractionation increased $7.1 quarter-to-quarter primarily due to (i) a 15 MBPD increase in processing volumes at our Norco facility resulting from an expansion we completed in the fourth quarter of 2003 and (ii) the effect of higher prices for NGL volumes sold by Norco that it earns ownership of through percent-of-liquids based fractionation contracts. NGL fractionation volumes were 239 MBPD during the third quarter of 2004 compared to 233 MBPD during the same period in 2003.

Petrochemical Services. Gross operating margin from our Petrochemical Services segment was $35.5 million for the third quarter of 2004 versus $8 million for the third quarter of 2003. The 2003 period includes a non-cash asset impairment charge of $22.5 million related to our investment in BEF, which owns a facility that produces octane additives. Excluding this charge, gross operating margin would have increased $5 million, which was primarily due to a $5.9 million increase in the gross operating margin generated by our octane enhancement business.

Nine months ended September 30, 2004 compared to nine months ended September 30, 2003

Revenues for the first nine months of 2004 increased $1.5 billion over those recorded during the first nine months of 2003. The increase in revenues is primarily due to (i) higher revenues from our NGL and petrochemical marketing activities due to increased sales volumes and prices and (ii) the addition of revenues from businesses acquired or consolidated since September 30, 2003, including BEF and our recently acquired South Texas midstream assets.

Costs and expenses increased $1.5 billion period-to-period primarily due to (i) higher product prices and volumes which resulted in an increase in the cost of sales of our NGL and petrochemical marketing activities and (ii) the addition of costs and expenses attributable to assets and businesses acquired or consolidated since September 30, 2003. The weighted-average NGL price was 68 CPG for the first nine months of 2004 compared to 56 CPG for the same period in 2003.

Our equity in the earnings of unconsolidated affiliates increased $58.9 million period-to-period. The equity earnings we recorded for the third quarter of 2003 were impacted by a $22.5 million non-cash asset impairment charge associated with our octane enhancement business. In addition, the first nine months of 2004 includes $32 million of equity earnings from GulfTerra GP, which we began consolidating on September 30, 2004 as a result of completing the GulfTerra Merger.

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

Offshore Pipelines & Services. Gross operating margin from our Offshore Pipelines & Services segment was $2.6 million for the first nine months of 2004 compared to $5.4 million for the same period in 2003. Overall, natural gas throughput volumes were 423 MMBtu/d for the first nine months of 2004 compared to 451 MMBtu/d for the same period in 2003. The $2.8 million decrease in gross operating margin for this segment is attributable to lower equity earnings from our Neptune natural gas pipeline investment.

Onshore Natural Gas Pipelines & Services. Gross operating margin from our Onshore Natural Gas Pipelines & Services segment was $18.9 million for the first nine months of 2004 versus $14.2 million for the same period in 2003. Overall, natural gas pipeline throughput volumes were 650 MMBtu/d during the 2004 period compared to 590 MMBtu/d for the 2003 period. The $4.7 million increase in gross operating margin for this segment is primarily due to higher natural gas transportation and sales volumes for our Acadian subsidiary during the 2004 period. Natural gas prices averaged $5.81 per MMBtu during the first nine months of 2004 compared to $5.65 per MMBtu during the same period in 2003.

NGL Pipelines & Services. Gross operating margin from our NGL Pipelines & Services segment was $231.7 million for the first nine months of 2004 compared to $230.6 million for the same period in 2003. Gross operating margin from natural gas processing increased $11.6 million period-to-period due to improved processing economics in the 2004 period; the addition of $7.8 million of gross operating margin for the month of September 2004 from our newly acquired South Texas midstream assets; both partially offset by lower results from our NGL marketing activities in the 2004 period. Indicative gas processing gross spreads on the U.S. Gulf Coast averaged 17 CPG during the first nine months of 2004 compared to 6 CPG during the first nine months of 2003, which resulted in an increase in the amount of NGLs extracted. Equity NGL production was 47 MBPD for the first nine months of 2004 versus 42 MBPD for the same period in 2003. Natural gas processing volumes under contracts with fee-based components increased to 944 MMcf/d for the first nine months of 2004 from 150 MMcf/d in the same period of 2003 reflecting amendments to our natural gas processing contract mix.

Gross operating margin from NGL pipelines decreased $12.6 million period-to-period primarily due (i) a $4 million non-cash asset impairment charge we recognized in the third quarter of 2004 for an NGL storage facility; (ii) a decrease in gross operating margin from our Mid-America and Seminole pipelines primarily due to increased repair, maintenance and fuel costs, including $6.5 million associated with our pipeline integrity inspection program; and (iii) lower gross operating margin from our Lou-Tex NGL pipeline resulting from a 47% decrease in throughput rates. Net NGL transportation volumes were 1,358 MBPD for the first nine months of 2004 versus 1,273 MBPD for the same period in 2003.

Gross operating margin from NGL fractionation increased $2.1 million period-to-period. NGL fractionation volumes were 235 MBPD during the first nine months of 2004 compared to 223 MBPD for the same period in 2003. Gross operating margin from our Norco facility increased by $14.5 million primarily due to (i) a 25 MBPD increase in volumes at our Norco facility resulting from an expansion completed in the fourth quarter of 2003 and (ii) the effect of higher prices for NGL volumes sold by Norco that it earns ownership of through percent-of-liquids based fractionation contracts. The improved results from Norco were partially offset by a $10.6 million decrease in gross operating margin period-to-period from our Mont Belvieu NGL fractionator attributable to the timing of gains and losses associated with the measurement of NGLs in storage pending fractionation. The 2004 period includes $3.5 million in measurement losses versus $4.3 million in measurement gains for the 2003 period.

Petrochemical Services. Gross operating margin from our Petrochemical Services segment was $90.8 million for the first nine months of 2004 versus $51.2 million for the first nine months of 2003. The 2003 period includes a non-cash asset impairment charge of $22.5 million related to our investment in a facility that produces octane additives. Gross operating margin from propylene fractionation increased $9.5 million period-to-period primarily due to higher petrochemical marketing sales volumes, which benefited from the effects of higher polymer grade propylene prices during 2004. Propylene fractionation volumes were 58 MBPD for the first nine months of 2004 versus 57 MBPD during the same period in 2003. Gross operating margin from isomerization decreased by $3.1 million period-to-period primarily due to lower volumes. Isomerization volumes were 73 MBPD for the first nine months of 2004 versus 80 MBPD for the first nine months of 2003.

Historical GulfTerra

As noted under “Recent Developments,” GulfTerra is one of the premier midstream energy companies in the United States. The following information is presented to assist the reader in identifying the magnitude of GulfTerra’s historical results of operations. When considered along with our historical results of operations, we believe this information is useful as an indicator of potential future trends in our combined results of operations now that the GulfTerra Merger is completed. To aid in comparability with our information, we have reclassified GulfTerra’s historical income statement amounts to conform to our method of financial statement presentation.

GULFTERRA ENERGY PARTNERS, L.P.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in thousands)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	**2003**	**2004**	**2003**
Revenues	$231,165	$213,831	$ 676,722	$ 680,957
Costs and Expenses				
Operating costs and expenses	140,422	110,628	392,429	399,865
Selling, general and administrative	14,572	11,123	39,829	36,020
Total	154,994	121,751	432,258	435,885
Equity in Income of Unconsolidated Affiliates	2,101	3,195	7,567	9,498
Operating Income	78,272	95,275	252,031	254,570
Other Income (Expense)				
Interest expense	(27,951)	(33,197)	(82,678)	(99,521)
Loss due to early redemptions of debt	(5,209)	(1,225)	(21,494)	(4,987)
Other, net	188	250	472	942
Total	(32,972)	(34,172)	(103,700)	(103,566)
Income Before Minority Interest	45,300	61,103	148,331	151,004
Minority Interest	1,813	(889)	1,825	(969)
Income from Continuing Operations	$ 47,113	$ 60,214	$ 150,156	$ 150,035
Calculation of total gross operating margin:				
Operating income	$ 78,272	$ 95,275	$ 252,031	$ 254,570
Add: Depreciation, depletion and amortization	28,994	25,218	81,297	73,761
Gain on sale of assets	(12)	(18,964)	(36)	(18,707)
Selling, general and administrative costs	14,572	11,123	39,829	36,020
Gross operating margin in total	$121,826	$112,652	$ 373,121	$ 345,644

The following discussion is an analysis of the changes in GulfTerra’s operating income for the periods presented in the preceding table.

Three months ended September 30, 2004 compared to three months ended September 30, 2003

GulfTerra’s operating income was $78.3 million for the third quarter of 2004 in comparison to $95.3 million for the third quarter of 2003. The decrease in operating income is primarily attributable to the $19 million gain that GulfTerra recognized in July 2003 on the sale of a 50% interest in Cameron Highway to Valero Energy Corporation. Additionally, operating income decreased quarter-to-quarter due to merger-related costs of $14.4 million that were recognized during the third quarter of 2004. These merger-related costs were primarily for advisory fees, retention bonuses and the repurchase of employee and director unit options. These decreases are offset by increased operating income associated with assets placed in service during the third quarter of 2004, primarily the Marco Polo natural gas and oil pipelines, the Marco Polo TLP and the Phoenix natural gas gathering system. Additionally, operating income increased as a result of a rise in natural gas and NGL prices quarter-to-quarter and increased volumes associated with new production in 2004.

Nine months ended September 30, 2004 compared to nine months ended September 30, 2003

GulfTerra's operating income was $252 million for the first nine months of 2004 in comparison to $254.6 million for the first nine months of 2003. The decrease in operating income is partially attributable to the $19 million gain that GulfTerra recognized in July 2003 on the sale of a 50% interest in Cameron Highway to Valero Energy Corporation. Additionally, operating income decreased due to merger-related costs of $22.2 million that were recognized during the first nine months of 2004. These merger-related costs were primarily for advisory fees, retention bonuses and the repurchase of employee and director unit options. These decreases are offset by increased operating income associated with assets placed in service during the third quarter of 2004, primarily the Marco Polo natural gas and oil pipelines, the Marco Polo TLP and the Phoenix natural gas gathering system. Additionally, operating income increased as a result of a rise in natural gas and NGL prices period-to-period and increased volumes associated with new production in 2004. Operating income on the Texas intrastate pipeline system increased period-to-period primarily as a result of increased fee based revenues and the revaluation of natural gas imbalances, and operating income for the NGL pipeline systems increased period-to period due to increased volumes as one of the pipelines was down for maintenance through the third quarter of 2003.

Pro Forma Financial Information

Please read Note 3 of the Notes to Unaudited Condensed Consolidated Financial Statements for information regarding the pro forma effects of the GulfTerra Merger and related transactions on our historical earnings.

OUR LIQUIDITY AND CAPITAL RESOURCES

General

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. On September 30, 2004, we had approximately $5.6 billion in principal outstanding under various debt agreements, including $921.5 million of GulfTerra senior and senior subordinated notes consolidated on that date as a result of completing the GulfTerra Merger. Our September 30, 2004 Unaudited Condensed Consolidated Balance Sheet also reflects $1.1 billion of cash held in escrow (classified as a component of "Restricted Cash" on that date) that was used on October 5, 2004 to complete our tender offers for GulfTerra's senior and subordinated notes. For additional information regarding our debt, please read "– *Our debt obligations*."

Effective registration statements

We have on file with the SEC a $1.5 billion universal shelf registration statement covering the issuance of an unallocated amount of partnership equity or public debt obligations (separately or in combination). Since June 2003, we have sold 48,410,317 common units under this registration statement. In May 2004, we sold 17,250,000 common units under this registration statement from which we received net proceeds of $353.1 million, including Enterprise GP's proportionate net capital contribution of $7.1 million. In August 2004, we sold 17,250,000 common units under this registration statement from which we received net proceeds of $341.2 million, including Enterprise GP's proportionate net capital contribution of $6.8 million. In October and November 2004, we sold 1,950,317 common units under this registration statement from which we received net proceeds of $39.6 million, including

Enterprise GP’s proportionate net capital contributions. After deducting for these 2003 and 2004 equity offerings, the amount available for future offerings under this shelf registration statement is approximately $480 million.

In April 2004, we filed a new registration statement with the SEC covering an additional 10,000,000 common units issuable under our Distribution Reinvestment Plan (or “DRIP”). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional common units. The new registration statement increased the number of common units issuable under the DRIP from 5,000,000 to 15,000,000. We expect to use the cash generated from this reinvestment program primarily for general partnership purposes. Since its inception in August 2003 through September 30, 2004, we have issued 5,794,624 common units under this and a related program generating net proceeds (including Enterprise GP’s proportionate net capital contributions) of approximately $122 million. This amount includes 1,053,510 common units issued in February 2004, 1,729,904 common units issued in May 2004 and 173,033 common units issued in August 2004, which together generated proceeds of approximately $61 million. In November 2004, we issued an additional 2.2 million common units under this program, which generated net proceeds of approximately $49.3 million (including Enterprise GP’s proportionate net capital contribution).

To support our growth objectives and financial flexibility, EPCO has reinvested approximately $105 million of its cash distributions since August 2003 through the DRIP (including $50 million during the first nine months of 2004). In addition, EPCO has announced that it expects to reinvest an additional $60 million of its anticipated quarterly distributions through the first quarter of 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.

Series F2 convertible units assumed in connection with the GulfTerra Merger

In May 2003, GulfTerra issued 80 Series F convertible units in a registered offering to an institutional investor. Each Series F convertible unit is comprised of two separate detachable units – a Series F1 convertible unit and a Series F2 convertible unit – that have identical terms except for vesting and termination dates and the number of common units into which they may be converted. Prior to the GulfTerra Merger, all the Series F1 convertible units were converted. As a result of the GulfTerra Merger, we assumed GulfTerra’s obligations associated with the 80 Series F2 convertible units. All Series F2 convertible units outstanding at the merger date were converted into rights to receive Enterprise common units. The number of Enterprise common units and the price per unit at conversion were adjusted based on the 1.81 exchange ratio. The Series F2 convertible units were convertible into up to $40 million of Enterprise common units.

On October 29, 2004, 60 of the 80 outstanding Series F2 convertible units were converted into 1,458,434 Enterprise common units. As a result of this conversion, we received a payment of $30 million from the holder of the Series F2 convertible units (representing a conversion price of $20.57 per Enterprise common unit). Net proceeds from this conversion, including Enterprise GP’s proportionate capital contribution of $0.6 million, were $29.7 million after deducting transaction costs of $0.9 million.

On November 8, 2004, the remaining 20 outstanding Series F2 convertible units were converted into 491,883 Enterprise common units. As a result of this conversion, we received a payment of $10 million from the holder of the Series F2 convertible units (representing a conversion price of $20.33 per Enterprise common unit). Net proceeds from this conversion, including Enterprise GP’s proportionate capital contribution of $0.2 million, were $9.9 million after deducting transaction costs of $0.3 million.

Nine months ended September 30, 2004 compared to nine months ended September 30, 2003

The following discussions highlight significant period-to-period comparisons in consolidated operating, investing and financing cash flows:

	For the Nine Months Ended September 30,	
	2004	**2003**
Net income	$ 152,907	$ 70,349
Adjustments to reconcile net income to cash flow from operating activities before changes in operating accounts:		
Depreciation and amortization in operating costs and expenses	94,976	83,844
Amortization in interest expense	2,868	12,237
Distributions received from unconsolidated affiliates: (1)		
GulfTerra GP (2)	32,347	
Other equity method investments (3)	22,233	25,703
Equity in (income) loss of unconsolidated affiliates: (1)		
GulfTerra GP (2)	(32,025)	
Other equity method investments (4)	(10,199)	16,647
Increase in restricted cash for operating activities (5)	(3,036)	(5,904)
Cumulative effect of change in accounting principles	(10,781)	
Other (6)	24,216	15,845
Cash flow from operating activities before changes in operating accounts	273,506	218,721
Net effect of changes in operating accounts	(240,526)	3,944
Cash provided by operating activities	$ 32,980	$ 222,665

(1) Distributions from unconsolidated affiliates and equity in income of unconsolidated affiliates have been presented in a manner to aid in comparability between periods.
(2) We acquired our 50% non-voting interest in GulfTerra GP in December 2003. We accounted for our investment in GulfTerra GP using the equity method through September 30, 2004.
(3) The 2003 period includes $7.2 million of cash distributions attributable to unconsolidated affiliates which became consolidated subsidiaries in 2003 and 2004.
(4) The 2003 period includes $24.7 million of losses attributable to unconsolidated affiliates which became consolidated subsidiaries in 2003 and 2004.
(5) Restricted cash for operating activities consists of amounts held by a brokerage firm as margin deposits associated with our financial instruments portfolio and for the physical purchase of natural gas made on the NYMEX exchange.
(6) The 2004 period includes a $4 million non-cash asset impairment charge recorded in third quarter of 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. The net effect of changes in operating accounts is generally the result of timing of cash receipts from sales and cash payments for purchases and other expenses near the end of each period. In addition, operating cash inflows and outflows related to increases or decreases in inventory are influenced by changes in commodity prices and our marketing activities. 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 sector, 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 additional information regarding risk factors pertinent to our business, please read "*Cautionary Statement Regarding Forward-Looking Information and Risk Factors*" on page 54 of this quarterly report.

Operating activities. For the nine months ended September 30, 2004 and 2003, cash provided by operating activities was $33 million and $222.7 million, respectively. As shown in the preceding table, cash flow before the net effect of changes in operating accounts was an inflow of $273.5 million for the 2004 period versus $218.7 million for the 2003 period. We believe that cash flow from operating activities before the net effect of changes in operating accounts is an important measure of our ability to generate core cash flows from our assets and other investments. The period-to-period fluctuation in the net effect of changes in operating accounts primarily reflects increased expenditures for inventories, which are mainly attributable to significantly higher commodity prices and slightly higher volumes held in inventory.

Distributions received from our equity method unconsolidated affiliates were $54.6 million for the 2004 period compared to $25.7 million for the 2003 period and equity income received from our equity method unconsolidated affiliates was $42.2 million for the 2004 period compared to a loss of $16.6 million for the 2003 period. The increases in these components of our cash flows is primarily due to cash distributions and equity income received from GulfTerra GP and VESCO, offset by the effects of consolidating former equity method investments as a result of acquisitions. As a result of the GulfTerra Merger, GulfTerra GP became a wholly-owned subsidiary of the Operating Partnership (see Note 3 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report). On July 1, 2004, we changed our method of accounting for VESCO from the cost method to the equity method in accordance with EITF 03-16 (See Note 1 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report). The period-to-period fluctuation in the restricted cash balance is primarily due to the timing of physical purchases of natural gas on the NYMEX exchange.

Investing activities. For the nine months ended September 30, 2004 and 2003, we used $734.7 million and $153.5 million, respectively, for investing activities. During 2004, we used $637.3 million to complete the GulfTerra Merger. Additionally, during 2004, we used $57.9 million to purchase an additional 16.7% membership interest in Tri-States, a 10% equity interest in Seminole and the remaining 33.3% ownership interests in BEF. The 2003 period included our purchases of the Port Neches Pipeline, the remaining 50% ownership interest in EPIK and an additional 33.33% interest in BEF. Capital expenditures were $38.9 million for the 2004 period versus $98 million for the 2003 period. For additional information regarding our capital expenditures, please read "*Capital Spending*" on page 79. Our investments in and advances to unconsolidated affiliates for the 2003 period included amounts we contributed to our Gulf of Mexico natural gas pipeline investments for their expansion capital projects.

Financing activities. Our financing activities were a cash inflow of $817.9 million during the first nine months of 2004 versus a cash outflow of $42.8 million during the first nine months of 2003. During the first nine months of 2004, we had net borrowings under our debt agreements of $1.4 billion compared to net repayments of $356.8 million for the same period in 2003. On September 30, 2004, we borrowed approximately $2.8 million under our new 364-Day Acquisition Revolving Credit Facility and Multi-Year Revolving Credit Facility "B" to (a) fund $655.3 million in cash payment obligations to El Paso under Steps Two and Three of the GulfTerra Merger transactions, (b) escrow $1.1 billion to finance our tender offers for GulfTerra's senior and senior subordinated notes and (c) extinguish $962 million outstanding under GulfTerra's revolving credit facility and secured term loans. Our repayments of debt during the first nine months of 2004 reflect the use of proceeds from our May 2004 and August 2004 equity offerings to repay the $225 million Interim Term Loan and to temporarily reduce amounts outstanding under our pre-merger revolving credit facilities. The 2003 period reflects our issuance of Senior Notes C ($350 million in principal amount) and Senior Notes D ($500 million in principal amount) and the final repayment of $1 billion that was outstanding under the bridge loan financing we used to purchase interest in the Mid-America and Seminole pipelines. Repayments of debt during the first nine months of 2003 also reflect the use of proceeds from our January 2003 and June 2003 equity offerings.

Cash distributions to partners increased from $223.4 million during the first nine months of 2003 to $278.6 million during the same period in 2004. The increase in cash distributions is primarily due to an increase in both the declared quarterly distribution rates and the number of units eligible for distributions. 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 sale of common units were $755.9 million for the first nine months of 2004 compared to $540.2 million for the same period in 2003. Both amounts include Enterprise GP's net proportionate capital contributions. In May 2004, we sold 17,250,000 common units to the public (including the underwriters' overallotment amount of 2,250,000 common units) at an offering price of $21.00 per unit. Net proceeds from this offering, including Enterprise GP's proportionate net capital contribution of $7.1 million, were $353.1 million after deducting applicable underwriting discounts, commissions and offering expenses of $16.3 million. In August 2004, we sold 17,250,000 common units to the public (including the underwriters' overallotment amount of 2,250,000 common units) at an offering price of $20.20 per unit. Net proceeds from this offering, including Enterprise GP's proportionate net capital contribution of $6.8 million, were approximately $341.2 million after deducting applicable underwriting discounts, commissions and offering expenses of $13.9 million. The 2004 period also includes $61.9 million in proceeds from the sale of 2,912,864 common units in connection with our DRIP, the proceeds of which were primarily used for working capital purposes. Proceeds from the issuance of common units during the first nine months of 2003 were $540.2 million and reflect the sale of 14,662,500 and 11,960,000 common units in our January 2003 and June 2003 equity offerings, respectively, and the sale of 1,268,404 common units in connection with our DRIP.

Our debt obligations

On September 30, 2004, we borrowed approximately $2.8 billion under revolving credit facilities to (a) fund $655.3 million in cash payment obligations to El Paso under Steps Two and Three of the GulfTerra Merger transactions, (b) escrow $1.1 billion to finance our tender offers for GulfTerra's senior and senior subordinated notes and (c) extinguish $962 million outstanding under GulfTerra's revolving credit facility and secured term loans. Our long-term debt at September 30, 2004 includes the remaining debt obligations of GulfTerra as appropriate in consolidation.

On October 4, 2004, we completed our issuance of $2 billion in Rule 144A private placement senior notes (Senior Notes E, F, G, and H) and used the proceeds to reduce borrowings made under our new revolving credit facilities on September 30, 2004. On October 5, 2004, we used the $1.1 billion in escrowed funds to complete our cash tender offers for substantially all of GulfTerra's senior and senior subordinated notes. As a result of the significant changes in the composition of our long-term debt between September 30 and October 5, the following discussion of our debt obligations is focused on our current obligations.

Our debt consisted of the following at the dates indicated:

	October 5, 2004	September 30, 2004	December 31, 2003
Operating Partnership debt obligations:			
Interim Term Loan, variable rate, repaid in May 2004 (1)			$ 225,000
364-Day Revolving Credit Facility, variable rate, $230 million borrowing capacity, terminated in August 2004			70,000
Multi-Year Revolving Credit Facility "A," variable rate, $270 million borrowing capacity, terminated in August 2004			115,000
364-Day Acquisition Revolving Credit Facility, variable rate, due September 2005, $2.25 billion borrowing capacity (2)	$ 242,229	$2,250,000	
Multi-Year Revolving Credit Facility "B," variable rate, due September 2009, $750 million borrowing capacity (2)	545,000	545,000	
Seminole Notes, 6.67% fixed-rate, $15 million due in December 2004 and 2005 (3)	30,000	30,000	30,000
MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000	54,000
Senior Notes A, 8.25% fixed-rate, due March 2005	350,000	350,000	350,000
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	450,000	450,000
Senior Notes C, 6.375% fixed-rate, due February 2013	350,000	350,000	350,000
Senior Notes D, 6.875% fixed-rate, due March 2033	500,000	500,000	500,000
Senior Notes E, 4.00% fixed-rate, due October 2007	500,000		
Senior Notes F, 4.625% fixed-rate, due October 2009	500,000		
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000		
Senior Notes H, 6.65%, fixed-rate, due October 2034	350,000		
GulfTerra debt obligations:			
Senior Notes, 6.25% fixed-rate, due June 2010	750	250,000	
Senior Subordinated Notes, 8.50% fixed-rate, due June 2010	3,858	215,915	
Senior Subordinated Notes, 8.50% fixed-rate, due June 2011	1,777	321,600	
Senior Subordinated Notes, 10.625% fixed-rate, due December 2012	84	134,000	
Fair value of GulfTerra Notes at merger closing date		132,383	
Total principal amount	4,527,698	5,582,898	2,144,000
Net unamortized discounts	(5,880)	(5,880)	(5,983)
Other	2,344	2,344	1,531
Subtotal long-term debt	4,524,162	5,579,362	2,139,548
Less current maturities of debt (4)	(607,212)	(607,212)	(240,000)
Long-term debt	$3,916,950	$4,972,150	$1,899,548
Cash held in escrow to complete tender offers (5)	$ -	$1,100,000	
Standby letters of credit outstanding (6)	$ 20,850	$ 20,850	$ 1,300

(1) We used the proceeds from our May 2004 common unit offering to fully repay and terminate the Interim Term Loan.

(2) Our 364-Day Acquisition Revolving Credit Facility and Multi-Year Revolving Credit Facility "B" became effective concurrent with the closing of the GulfTerra Merger on September 30, 2004. The new $750 million Multi-Year Revolving Credit Facility "B" replaced the $230 million 364-Day Revolving Credit Facility and the $270 million Multi-Year Revolving Credit Facility "A."

(3) Solely as it relates to the assets of our GulfTerra and Seminole subsidiaries, our $4.5 billion in senior indebtedness at October 5, 2004 is structurally subordinated and ranks junior in right of payment to the $36 million of indebtedness of GulfTerra and Seminole.

(4) 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, 2003 reflected our option and ability to convert any revolving credit balance outstanding at maturity under the 364-Day Revolving Credit Facility to a one-year term loan (that would have been due October 2005) in accordance with the terms of the credit agreement. With respect to September 30, 2004 and October 5, 2004, we repaid approximately $2 billion outstanding under the 364-Day Acquisition Revolving Credit Facility using proceeds from our October 4, 2004 long-term senior notes offering, which effectively converts the amount repaid to long-term debt.

(5) We borrowed $1.1 billion on September 30, 2004 under our 364-Day Acquisition Revolving Credit and escrowed the funds in anticipation of completing our four cash tender offers for GulfTerra's senior and senior subordinated notes on October 5, 2004.

(6) We had $100 million of leters of credit capacity available under our new $750 million Multi-Year Revolving Credit Facility "B" at September 30, 2004 compared to $75 million of leters of credit capacity available under our previous $270 million Multi-Year Revolving Credit Facility "A" at December 31, 2003.

General description of consolidated debt

The following summarizes significant aspects of our debt obligations at September 30, 2004 and October 5, 2004:

Parent-Subsidiary guarantor relationships. We act as guarantor of the debt obligations of our Operating Partnership, with the exception of the Seminole Notes and the senior and 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 an effective 86.6% of its capital stock). The senior and senior subordinated notes of GulfTerra are unsecured obligations of GulfTerra (of which we own 100% of its limited and general partnership interests).

GulfTerra's Senior Subordinated and Senior Notes. As a result of completing the GulfTerra Merger on September 30, 2004, we recorded in consolidation GulfTerra's $921.5 million of outstanding senior and senior subordinated notes. Of this amount, $915 million was purchased on October 5, 2004 by our Operating Partnership pursuant to its tender offers. The note holders also approved amendments in connection with accepting the tender offers that removed all restrictive covenants governing the notes. For additional information regarding the tender offers, please read " *– 364-Day Acquisition Revolving Credit Facility – Tender offers for GulfTerra senior and senior subordinated notes*" within this general description of debt.

364-Day Acquisition Revolving Credit Facility. In August 2004, our Operating Partnership entered into a new 364-day revolving credit agreement. The $2.25 billion Acquisition Revolving Credit Facility is an unsecured 364-day facility that was used to provide interim financing for certain transactions associated with the GulfTerra Merger, the refinancing of GulfTerra's existing secured credit facility and term loans and the purchase of GulfTerra's senior and senior subordinated notes in connection with our Operating Partnership's tender offers for those notes. This facility became effective concurrent with the closing of the GulfTerra Merger and will mature on September 29, 2005. The Operating Partnership's borrowings under this agreement are unsecured general obligations that are non-recourse to Enterprise GP. We have guaranteed repayment of amounts due under this revolving credit agreement through an unsecured guarantee.

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 (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate plus an applicable margin or (3) a Competitive Bid Rate.

This credit agreement provides for the mandatory prepayment of loans and termination of commitments equal to the proceeds from and upon the consummation of any public or private debt or equity offerings by us on or after August 15, 2004, excluding equity issued with respect to our distribution reinvestment plan, employee unit purchase plan and the exercise of any outstanding options with respect to our common units. With the completion of our Rule 144A private placement offering of senior notes on October 4, 2004, we repaid approximately $2 billion borrowed under this facility, which reduced our borrowing capacity under this facility by an equal amount.

This revolving credit agreement contains various covenants related to our ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also requires us to satisfy certain financial covenants at the end of each fiscal quarter. If an event of default (as defined in the agreement) occurs, the Operating Partnership is prohibited from making distributions to us, which would impair our ability to make distributions to our partners. As defined in the agreement, we must maintain a specified level of consolidated net worth and certain financial ratios.

Tender offers for GulfTerra senior and senior subordinated notes

On August 4, 2004, in anticipation of completing the GulfTerra Merger, our Operating Partnership commenced four cash tender offers to purchase any and all of the outstanding senior and senior subordinated notes of GulfTerra having a total outstanding principal amount of approximately $921.5 million. In connection with the tender offers, GulfTerra executed supplements to the indentures governing these notes that eliminated certain restrictive covenants and default provisions contained in those indentures upon our purchase of more than a majority in principal amount of each series of the outstanding senior and senior subordinated notes.

Substantially all of the GulfTerra notes ($915 million of $921.5 million) were tendered pursuant to the tender offers. On September 30, 2004, we borrowed $1.1 billion under our 364-Day Acquisition Revolving Credit Facility in anticipation of completing the tender offers and placed these funds in escrow. On October 5, 2004, our Operating Partnership purchased the notes for a total price of approximately $1.1 billion, which included $27 million related to consent payments.

The following table shows the four GulfTerra senior debt obligations affected, including the principal amount of each series of notes tendered, as well as the payment made by Enterprise to complete the tender offers.

Description	Principal Amount Tendered	Cash payments made by Enterprise		
		Accrued Interest	Tender Price (1)	Total Price
8.50% Senior Subordinated Notes due 2010 (Represents 98.2% of principal amount outstanding)	$ 212,057	$ 6,209	$ 246,366	$ 252,575
10.625% Senior Subordinated Notes due 2012 (Represents 99.9% of principal amount outstanding)	133,916	4,901	167,612	172,513
8.50% Senior Subordinated Notes due 2011 (Represents 99.5% of principal amount outstanding)	319,823	9,364	359,379	368,743
6.25% Senior Notes due 2010 (Represents 99.7% of principal amount outstanding)	249,250	5,366	274,073	279,439
Totals	$ 915,046	$ 25,840	$1,047,430	$1,073,270

(1) Tender price includes consent payment of $30 per $1,000 principal amount tendered.

Multi-Year Revolving Credit Facility "B." In August 2004, our Operating Partnership entered into a five-year $750 million revolving credit agreement that includes a sublimit of $100 million for standby letters of credit. This facility became effective concurrent with the closing of the GulfTerra Merger and will mature on September 30, 2009. This facility replaced our existing $270 million Multi-Year Revolving Credit Facility "A" and $230 million 364-Day Revolving Credit Facility, which were terminated upon the effective date of the new facility. The Operating Partnership's borrowings under this agreement are unsecured general obligations that are non-recourse to Enterprise GP. We have guaranteed repayment of amounts due under this revolving credit agreement through an unsecured guarantee.

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 (1) the greater of (a) the Prime Rate or (b) the Federal Funds Effective Rate plus ½% or (2) a Eurodollar rate plus an applicable margin or (3) a Competitive Bid Rate. This revolving credit agreement contains various covenants similar to those of our 364-Day Acquisition Revolving Credit Facility.

Senior Notes issued on October 4, 2004. On September 23, 2004, our Operating Partnership priced a Rule 144A private placement 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. On October 4, 2004, these notes were issued. The interest rate, principal amount and net proceeds, before expenses, for each senior note in this offering are shown in the following table:

Senior Note Issued	Fixed Interest Rate	Principal Amount	Bond Discount	Proceeds to Us, Before Expenses
Senior Notes E, due October 2007	4.000%	$ 500,000	$ 2,140	$ 497,860
Senior Notes F, due October 2009	4.625%	500,000	4,405	495,595
Senior Notes G, due October 2014	5.600%	650,000	4,784	645,216
Senior Notes H, due October 2034	6.650%	350,000	4,203	345,797
Totals		$ 2,000,000	$ 15,532	$ 1,984,468

The net proceeds from this offering were used to reduce debt amounts outstanding under the Operating Partnership's $2.25 billion 364-Day Acquisition Revolving Credit Facility that was used to partially fund the GulfTerra Merger on September 30, 2004.

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.

Industrial Development Revenue Bonds. In April 2004, Petal Gas Storage L.L.C.("Petal"), a wholly-owned subsidiary of GulfTerra, borrowed $52 million from the Mississippi Business Finance Corporation ("MBFC") pursuant to a loan agreement between Petal and the MBFC. On the same date, the MBFC issued $52 million in Industrial Development Revenue Bonds to another wholly-owned subsidiary of GulfTerra. The loan agreement and the Industrial Development Revenue Bonds have identical fixed interest rates of 6.25% and maturities of fifteen years. The bonds and the associated tax exemptions are authorized under the Mississippi Business Finance Act. Petal may repay the loan agreement without penalty, and thus cause the Industrial Development Revenue Bonds to be redeemed, any time after one year from their date of issue. We have netted the loan amount and the bond amount of $52 million and the interest payable and interest receivable amount of $1.4 million on our Unaudited Condensed Consolidated Balance Sheet as of September 30, 2004. Beginning in the fourth quarter of 2004, we will also net the interest expense and interest income amounts attributable to these instruments on our Statements of Consolidated Operations. Our presentation of the Industrial Development Revenue Bonds is reflected in accordance with the provisions of FIN No. 39, "*Offsetting of Amounts Related to Certain Contracts*", and SFAS No. 140, *"Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*", since we have the ability and intent to offset these items.

Covenants. We were in compliance with the various covenants of our debt agreements at September 30, 2004 and December 31, 2003.

Loss due to write-off of unamortized debt issuance costs. As a result of terminating our 364-Day Revolving Credit Facility and our Multi-Year Revolving Credit Facility "A" on September 30, 2004, we expensed $0.7 million of unamortized debt issuance costs.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our variable rate debt obligations during the nine months ended September 30, 2004:

	Range of interest rates paid	Weighted-average interest rate paid
Interim Term Loan (terminated May 2004)	1.72% to 1.78%	1.73%
364-Day Revolving Credit Facility (terminated September 30, 2004)	1.72% to 4.00%	1.82%
Multi-Year Revolving Credit Facility “A” (terminated September 30, 2004)	1.67% to 4.25%	1.83%
364-Day Acquisition Revolving Credit Facility (effective September 30, 2004)	4.75%	4.75% (1-day only)
Multi-Year Revolving Credit Facility “B” (effective September 30, 2004)	4.75%	4.75% (1-day only)

Consolidated debt maturity table

The following table shows aggregate maturities of the principal amounts of long-term debt and other financing obligations for the remainder of 2004 and the following 4 years and in total thereafter at September 30, 2004 (i) on an actual basis and (ii) on a pro forma basis adjusted for debt-related subsequent events as described in the footnotes thereto.

	Historical September 30, 2004	Adjustments for Subsequent Events		Pro Forma September 30, 2004
2004	$ 15,000			$ 15,000
2005	2,614,983	$ (1,981,000)	(1)	607,212
		(26,771)	(2)	
2006	n/a			n/a
2007	n/a	500,000	(3)	500,000
2008	n/a			n/a
Thereafter	2,952,915	1,500,000	(3)	3,405,486
		(915,046)	(4)	
		(132,383)	(5)	
Total long-term debt, including current maturities	$ 5,582,898	$ (1,055,200)		$ 4,527,698

(1) Reflects the use of net proceeds from the October 2004 Senior Notes offering to reduce amounts outstanding under the $2.25 billion 364-Day Acquisition Revolving Credit Facility.
(2) Reflects the repayment of excess funds borrowed on September 30, 2004 under the 364-Day Acquisition Revolving Credit Facility.
(3) Reflects the issuance of Senior Notes E, F, G and H on October 4, 2004.
(4) Reflects the completion by our Operating Partnership of its tender offers to purchase $915 million of GulfTerra's senior and senior subordinated notes on October 5, 2004, which are eliminated in consolidation.
(5) Reflects the payment by our Operating Partnership of the premium associated with its tender offers completed on October 5, 2004.

Joint venture debt obligations

As a result of the GulfTerra Merger, we acquired ownership interests in three additional joint ventures having long-term debt obligations. The following table shows (i) our ownership interest in each entity at September 30, 2004, (ii) total long-term debt obligations (including current maturities) of each unconsolidated affiliates on that date on a 100% basis to the joint venture, (ii) the corresponding scheduled maturities of such long-term debt:

			Scheduled Maturities of Long-Term Debt					
	Our Ownership Interest	Total	2004	2005	2006	2007	2008	After 2008
Cameron Highway (1)	50.0%	$ 297,000			$ 16,250	$ 32,500	$ 156,250	$ 92,000
Deepwater Gateway	50.0%	149,500	$ 5,500	$ 22,000	22,000	22,000	22,000	56,000
Poseidon (2)	36.0%	116,000					116,000	
Evangeline	49.5%	40,650	5,000	5,000	5,000	5,000	5,000	15,650
Total		$ 603,150	$ 10,500	$ 27,000	$ 43,250	$ 59,500	$ 299,250	$ 163,650

(1) Cameron Highway has a total borrowing capacity under its project loan facility (as described below) of $325 million. The scheduled maturities for the Cameron Highway assume that the construction loan is or will be converted into a term loan on September 30, 2005 and the scheduled repayments will begin on December 31, 2007.

(2) Poseidon has a total borrowing capacity of $170 million under its revolving credit facility.

Please read Note 10 of our Unaudited Condensed Consolidated Financial Statements for additional information regarding the joint venture debt obligations.

Recent Rating Agency Actions

In May 2004, Moody’s Investors Service lowered its corporate credit ratings on Enterprise from Baa2 (investment grade) with a stable outlook to Baa3 (investment grade) with a negative outlook. In September 2004, Moody’s Investor Service affirmed its rating on our outstanding senior unsecured notes of Baa3 (investment grade) and changed its rating outlook on us from negative to stable.

In May 2004, Standard & Poor’s lowered its corporate credit ratings on Enterprise from BBB- (investment grade) with a negative outlook to BB+ (non-investment grade) with a stable outlook. It reaffirmed these ratings in September 2004.

In August 2004, Fitch Ratings initiated ratings coverage of our outstanding senior unsecured notes. Fitch assigned a rating to our notes of BBB- (investment grade) with a stable outlook.

Depending on our future operating results, these credit rating agencies may view our current levels of debt negatively. If one or more of these credit rating agencies were to downgrade our credit standing, we could experience an increase in our borrowing costs, difficulty accessing capital markets or a reduction in the market price of our common units. Such a development could adversely affect our ability to obtain financing for working capital, capital expenditures, acquisitions and to refinance indebtedness.

The May 2004 downgrade of our credit ratings resulted in an increase in our short-term borrowing costs. Our revolving credit facilities contain applicable margin provisions that can increase the interest rates and facility fees we pay our lenders when certain credit rating criteria are lowered. In general, the May 2004 downgrades increased the Eurodollar-based interest rates we were paying by 0.2% and facility fees by 0.05%. Our other borrowing interest rates were not affected.

Additionally, if our credit rating by Moody’s declines below Baa3 in combination with our credit rating at Standard & Poor’s remaining at BB+ or below, the $54 million principal balance of our MBFC Loan, and all related accrued and unpaid interest would become immediately due and payable 120 days following such event. If such an event occurred, we would have to redeem the MBFC Loan or provide an alternative credit agreement to support our obligation under the MBFC Loan.

Our material contractual obligations

As a result of the GulfTerra Merger and related transactions, our material contractual obligations associated with debt, operating leases and other long-term liabilities increased significantly from the levels shown in our Annual Report on Form 10-K for the year ended December 31, 2003. Our debt obligations increased as a result of borrowings made to complete the GulfTerra Merger, including the issuance of $2 billion in senior notes on October 4, 2005. Our operating lease commitments increased as a result of assuming the payment obligations relating to three storage facilities located in Texas (one natural gas and two NGL facilities). We also consolidated $42.4 million of other long-term liabilities of GulfTerra, which includes an estimated $21 million environmental reserve for remediation costs expected to be incurred over time associated with mercury gas meters. As of September 30, 2004, we had approximately $62 million in outstanding purchase commitments related to our share of capital projects, the majority of which pertain to pipeline and platform growth projects in the Gulf of Mexico. There was no material change in our other product purchase and service contract commitments as a result of the GulfTerra Merger.

The following table summarizes our current material contractual obligations related to debt and operating leases:

	Payment or Settlement due by Period				
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Time period during which obligation is due		(Remainder of 2004)	(1/1/2005 - 12/31/2006)	(1/1/2007 - 12/31/2008)	(Beyond 1/1/2009)
Operating lease obligations (1)	$ 72,750	$ 3,168	$ 23,983	$ 18,835	$ 26,764
Long-term debt, including current maturities (2)	4,527,698	15,000	607,212	500,000	3,405,486

(1) This amount represents our minimum lease obligations under operating lease agreements.
(2) We have long and short-term payment obligations under credit agreements such as our senior notes and revolving credit facilities.Amounts shown in the table represent our scheduled future maturities of long-term debt (including current maturities thereof)at October 5, 2004 for the periods indicated.For additional information regarding our debt obligations, please read " - *Our liquidity and capital resources - Our debt obligations*."

Capital spending

For the nine months ended September 30, 2004 and 2003, our capital spending for business combinations (including non-cash consideration amounts), property, plant and equipment and our unconsolidated affiliates was $3.6 billion and $145.4 million, respectively. The following table summarizes our capital spending by activity for the periods indicated:

	For the Nine Months Ended September 30, 2004	For the Nine Months Ended September 30, 2003
Capital spending for business combinations:		
GulfTerra Merger (Step Two transactions):		
Cash payments to El Paso	$ 500,000	
Transaction fees and other direct costs	22,525	
Cash received from GulfTerra	(40,453)	
Net cash payments	482,072	
Value of non-cash consideration issued or granted	2,870,454	
Total GulfTerra Merger Step Two consideration	3,352,526	
GulfTerra Merger (Step Three transactions):		
Cash payments to El Paso	155,277	
Other business combinations	57,935	$ 26,255
Total capital spending related to business combinations	3,565,738	26,255
Capital spending for property, plant and equipment		
Growth capital projects	22,944	83,010
Sustaining capital projects	16,001	14,958
Total capital spending for property, plant and equipment	38,945	97,968
Capital spending attributable to unconsolidated affiliates		
Investments in unconsolidated affiliates, excluding advances	925	21,217
Total capital spending	$ 3,605,608	$ 145,440

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 the Company is positioned to continue to grow through acquisitions that will expand its platform of assets and through growth capital projects. The combination of our operations with those of GulfTerra provide us with incremental growth opportunities for both onshore and offshore projects. We currently estimate that our capital spending over the next two to three years could approximate up to $2 billion, primarily for growth projects in the Gulf of Mexico and Western regions of North America.

For the remainder of 2004, we estimate our capital spending for property, plant and equipment at $124 million. We have a number of ongoing capital projects, including those we assumed as a result of the GulfTerra Merger (see the following discussion, "*Growth Capital Projects of GulfTerra*"). Our expenditure forecast of $124 million reflects $58 million in onshore and offshore natural gas pipeline and storage projects and $51 million in NGL pipeline and plant projects. An additional $20 million is expected to be spent to modify our octane additive production facility to produce iso-octane. We also expect to invest approximately $38 million in the capital projects of our unconsolidated affiliates during the remainder of 2004. As of September 30, 2004, we had approximately $62 million in outstanding purchase commitments related to our share of capital projects, the majority of which pertain to pipeline and platform growth projects in the Gulf of Mexico.

Growth Capital Projects of GulfTerra

Prior to the merger, GulfTerra had a number of midstream energy projects underway. The following information provides an update on these projects.

Cameron Highway oil pipeline. In September 2004, Cameron Highway, our 50% owned equity method investment, completed construction of the Cameron Highway oil pipeline. This 390-mile crude oil pipeline system has a transport capacity of approximately 500 MBPD and connects various designated crude oil receipt points extending from Ship Shoal Block 332 in the Gulf of Mexico to onshore delivery points located in the state of Texas. In July 2003, GulfTerra sold a 50% interest in Cameron Highway, which owns the Cameron Highway oil pipeline, to Valero for $86 million, forming a joint venture with Valero. Pursuant to the joint venture agreements, Valero is obligated to pay $5 million to GulfTerra now that the system is completed and another $11 million by the end of 2006.

Additionally, in July 2004, Cameron Highway executed an agreement with Kerr-McGee for the dedication and movement of crude oil production from the Constitution and Ticonderoga fields, along with other future production from several undeveloped blocks in the south Green Canyon area of the deepwater trend of the Gulf of Mexico. Under the terms of the agreement, production from Kerr-McGee's interest in Constitution, Ticonderoga and surrounding undeveloped blocks is dedicated to the Cameron Highway oil pipeline system for the life of the reserves. Cameron Highway expects volumes from these fields in the first half of 2006.

Marco Polo TLP and related oil and natural gas pipelines. The Marco Polo TLP was installed in the first quarter of 2004 and commenced operations in July 2004. The Marco Polo TLP has a maximum handling capacity of 120 MBPD of oil and 300 MMcf/d of natural gas. This TLP was designed and located to process oil and natural gas from Anadarko Petroleum Corporation's Marco Polo field located in Green Canyon Block 608. Deepwater Gateway, our 50% owned equity method investment which owns the Marco Polo TLP, began receiving monthly demand payments of $2.1 million in April 2004 and volumetric payments started in July 2004. We expect that the Marco Polo TLP will begin receiving production volumes from the K2 and K2 North Fields in the Green Canyon Block during the first quarter of 2005.

In addition to our 50% ownership interest in the Marco Polo TLP, we own 100% of the Marco Polo oil and natural gas export pipelines that transport production processed on the Marco Polo TLP to downstream markets. Construction on these export lines was completed in July 2004. The Marco Polo oil pipeline is a 36-mile, 14-inch oil pipeline with a transport capacity of 120 MBPD that interconnects with our Allegheny oil pipeline in Green Canyon Block 164. The Marco Polo natural gas pipeline is a 75-mile, 18-inch to 20-inch natural gas pipeline with a capacity of 400 MMcf/d that interconnects with our Typhoon natural gas pipeline in Green Canyon Block 236.

Phoenix gathering system. In July 2004, GulfTerra commenced operations of its 78-mile, 18-inch Phoenix natural gas gathering system, which has a transport capacity of 450 MMcf/d that interconnects with El Paso's ANR Pipeline system at Vermillion Block 397. The Phoenix natural gas gathering system gathers production from the Red Hawk Field, in which Kerr-McGee and Devon Energy Corporation each hold a 50% working interest. Kerr-McGee and Devon have dedicated multiple blocks at and in the proximity of the Red Hawk Field to this pipeline system for the life of the reserves, subject to certain release provisions.

Constitution gathering system. In July 2004, GulfTerra entered into a definitive agreement to construct, own, and operate oil and natural gas pipelines to provide production gathering services for the Constitution field, which is 100% owned by Kerr-McGee Oil & Gas Corporation. The Constitution field is located in 5,300 feet of water in Green Canyon Blocks 679 and 680 in the Central Gulf of Mexico. The new natural gas pipeline will be a 32-mile, 16-inch pipeline with a transport capacity of up to 200 MMcf/d and will connect to our existing Anaconda Gathering System (the combination of our Marco Polo natural gas pipeline and our Typhoon natural gas pipeline). The new oil pipeline will be a 70-mile, 16-inch pipeline with a minimum transport capacity of 80 MBPD that will connect with the Cameron Highway oil pipeline and Poseidon oil pipeline systems at the new Ship Shoal 332B platform. These pipelines are expected to cost $130 million to construct, and we plan to start construction in early 2005, with the first transportation volumes scheduled for the first half of 2006. We expect to fund this construction project through internally generated funds and borrowings under our revolving credit facilities. As of September 30, 2004, GulfTerra had spent $2.1 million related to the construction of this new system.

Front Runner oil pipeline. In July 2004, Poseidon, our 36% owned equity method investment, completed construction of its 36-mile, 14-inch Front Runner oil pipeline. We expect that this system will transport its first volumes late in the fourth quarter of 2004. The new oil pipeline has a capacity of 65 MBPD and connects the Front Runner platform with Poseidon's existing pipeline system at Ship Shoal Block 332. In October 2003, Poseidon began withholding distributions to their partners to fund its capital expenditures related to the Front Runner oil pipeline. Since Poseidon has completed construction of this pipeline, we expect to start receiving distributions again in late 2004 or early 2005.

Petal conversion project. In the third quarter of 2004, GulfTerra began to convert an existing brine well at its propane storage complex in Hattiesburg, Mississippi to natural gas service. This conversion will cost approximately $17 million and will create a new 1.8 Bcf natural gas storage cavern that will be integrated with our Petal natural gas storage facility. We expect to have the cavern in service during the first quarter of 2005. In the second quarter of 2004, GulfTerra executed long-term storage agreements with BP Energy Company for the entire capacity of the new natural gas cavern. As of September 30, 2004, GulfTerra had spent $1 million on this conversion project.

San Juan optimization project. In May 2003, GulfTerra commenced a $43 million project relating to the San Juan Basin assets. This project is expected to be completed in stages through 2006 and will result in increased capacity of up to 130 MMcf/d on the San Juan gathering system and increased market opportunities through a new interconnect at the tailgate of the Chaco plant. As of September 30, 2004, GulfTerra had spent $9.7 million on this project.

Purchase options associated with retained leases

EPCO contributed various equipment leases to us at our formation in 1998 for which EPCO has retained the cash payment obligations (the "retained leases"). EPCO has assigned to us the purchase options associated with the retained leases. During 2003, we exercised our option to purchase an isomerization unit and in October 2004 purchased the unit at a cost of $15 million, which approximated fair value. Should we decide to exercise the remaining purchase options associated with the retained leases (which are also at fair value), an additional $2.8 million would be payable in 2004, $2.3 million in 2008 and $3.1 million in 2016.

Pipeline Integrity Costs

Our NGL, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the U.S. Department of Transportation, through its Office of Pipeline Safety. This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (which include NGL and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs. In connection with the new regulations for hazardous liquid pipelines, we developed a pipeline integrity management program in 2002. We are currently preparing an integrity management program for our natural gas pipelines, which must be completed by December 2004.

During the first nine months of 2004, we spent approximately $11.5 million to comply with these new regulations, of which $6.8 million was recorded as an operating expense of our NGL Pipelines & Services segment. Based on information currently available, our cash outlays for this program (on a post-merger basis) through 2008 are estimated as follows: $5 million for remainder of 2004; $58 million for 2005; $50 million for 2006; $73 million for 2007; and $62 million for 2008.

These forecasted costs for 2005 and 2006 are net of an indemnification GulfTerra received from El Paso prior to the GulfTerra Merger. In April 2002, GulfTerra acquired several midstream assets located in Texas and New Mexico from El Paso (the "EPN Holdings" acquisition). These assets included the Texas Intrastate Pipelines, the Permian Basin gas gathering system and the Indian Basin gas plant. Pursuant to the purchase and sale agreement between GulfTerra and El Paso for these assets, El Paso agreed to indemnify GulfTerra against any and all pipeline integrity costs incurred (whether paid or payable) with respect to the EPN Holding assets for each year through December 31, 2006, to the extent that such annual costs exceed $5 million.

RECENT ACCOUNTING DEVELOPMENTS

FIN 46, "Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51." This interpretation of ARB No. 51 addresses requirements for accounting consolidation of a variable interest entity ("VIE") with its primary beneficiary. In general, if an equity owner of a VIE meets certain criteria defined within FIN 46, the assets, liabilities and results of the activities of the VIE should be included in the consolidated financial statements of the owner. Our adoption of FIN 46 (as amended by FIN 46R) in 2003 has had no material effect on our consolidated financial statements. Due to the complexity of FIN 46 (as amended by FIN 46R and interpreted), the FASB is continuing to provide guidance regarding implementation issues. Since this guidance is still continuing, our conclusions regarding the application of this guidance may be altered. As a result, adjustments may be recorded in future periods as we adopt new FASB interpretations of FIN 46.

EITF 03-06, "Participating Securities and the Two-Class Method under SFAS No. 128." This accounting guidance, which is applicable for the period beginning April 1, 2004, requires the two-class method for calculating earnings per share for certain securities that are considered to participate in earnings with common shareholders. Under the two-class method, distributions to equity owners are subtracted from earnings, and any remaining earnings would be allocated to the various classes of owners in proportion to their right to receive distributions as if those earnings had been distributed. The total distributions to each class of owner plus the amount allocated to each class would be used to compute earnings per unit for that class. Since our distributions to owners exceeded earnings during the periods presented, as has historically been the case, the two-class method did not produce any change from the way we have traditionally computed earnings per unit. As a result, our adoption of this standard had no effect on our earnings per unit calculations.

EITF 03-16, "Accounting for Investments in Limited Liability Companies." This accounting guidance requires that an investment in a LLC that has separate ownership accounts for each investor be accounted for similar to a limited partnership investment under SOP No. 78-9, "*Accounting for Investments in Real Estate Ventures*." Under this new guidance (applicable for the period beginning July 1, 2004), investors are required to apply the equity method of accounting to their investments at a much lower ownership threshold (typically any ownership interest greater than 3-5%) than the 20% threshold applied under APB Opinion No. 18, "*The Equity Method of Accounting for Investments in Common Stock*." Our implementation of this accounting guidance is discussed under Note 1 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

OUR CRITICAL ACCOUNTING POLICIES

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

As a result of the GulfTerra Merger, we have modified our critical accounting policies to include certain policies that we deemed to be critical in the financial reporting process of the combined company. The following information summarizes 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. We use the straight-line method to depreciate the majority of our property, plant and equipment. Our estimate of an asset's useful life is based on a number of assumptions including technological changes that may affect the asset's usefulness and the manner in which we intend to physically use the asset. If we subsequently change our assumptions regarding these factors, it would result in an increase or decrease in depreciation expense.

At September 30, 2004 and December 31, 2003, the net book value of our property, plant and equipment was $7.7 billion and $3 billion. 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

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. Long-lived assets with recorded values that are not expected to be recovered through future expected cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the existing asset. Our estimates of such undiscounted 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. An impairment charge would be recorded for the excess of the long-lived asset's carrying value and its fair value, which is based on a series of assumptions similar to those used to derive undiscounted cash flows but incorporating probabilities that reflect a range of possible outcomes and market value and replacement cost estimates.

Equity method investments are evaluated for impairment whenever events or changes in circumstances indicate that there is a loss in value of the investment which is an other than temporary decline. Examples of such events or changes include continued operating losses of the investee or long-term negative changes in the investee's industry. The carrying value of an equity method investment is not recoverable if it exceeds the sum of discounted estimated cash flows expected to be derived from the investment. This estimate of discounted cash flows is based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment.

Due to a deteriorating business environment, BEF evaluated the carrying value of its long-lived assets for impairment during the third quarter of 2003. This review indicated that the carrying value of its long-lived assets exceeded their collective fair value, which resulted in a non-cash impairment charge of $67.5 million. Since BEF was one of our equity investments at that time, our share of this loss was $22.5 million and was recorded as a component of "Equity in income (loss) of unconsolidated affiliates" in our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income for the three and nine months ended September 30, 2003. As a consolidated subsidiary, BEF continues to review its operations on quarterly basis due to the challenging and uncertain business environment in which it operates.

In order to complete the GulfTerra Merger, we are required under a consent decree published for comment by the FTC on September 30, 2004 to sell our undivided 50% interest in a Mississippi propane storage facility by December 31, 2004. As a result of our determination of this long-lived asset's current market value, we recorded a non-cash $4 million asset impairment charge during the third quarter of 2004 that is a component of operating costs and expenses. The nominal fair value of this facility was reclassified from "Property, Plant and Equipment" to "Assets Held for Sale" on our Unaudited Condensed Consolidated Balance Sheet at September 30, 2004. The operating results of this facility (including the recent asset impairment charge) are not material to our historical or ongoing operations; therefore, these results have not been presented as discontinued operations in our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income.

Amortization methods and estimated useful lives of qualifying intangible assets

At September 30, 2004 and December 31, 2003, the carrying value of our intangible asset portfolio was $961.9 million and $268.9 million. As a result of the GulfTerra Merger, the preliminary value allocated to intangible assets was $705.1 million. Our intangible assets primarily consist of the estimated value assigned to certain customer relationships and contract-based assets.

Our customer relationship intangible assets represent the customer base that GulfTerra and the South Texas midstream assets serve through providing services, including natural gas gathering and processing, NGL fractionation and pipeline transportation. These businesses conduct the majority of their business through the use of written contracts; thus, the customer relationships represent the rights we own arising from those contractual agreements. The value of these customer relationships are being amortized on a straight-line basis over the estimated economic life of the resource base to which they relate, which we estimate could range from 18 to 43 years depending on the asset. Our estimate of the economic life of each resource based is based on a number of factors, including third-party reserve estimates, the economic viability of production and exploration activities and other factors.

Our contract-based intangible assets represent the rights we own arising from contractual agreements. A contract-based intangible asset with a finite useful life is amortized over its estimated useful life. Our estimate of useful life is based on a number of factors, including the expected useful life of related assets (i.e., fractionation facility, pipeline, etc.) and the effects of obsolescence, demand, competition and other factors.

If our underlying assumptions regarding the useful life of an intangible asset change, we then might need to adjust the amortization period of such asset which would increase or decrease amortization expense. Additionally, if we determine that an intangible asset's unamortized cost may not be recoverable due to impairment, this would result in a charge against earnings. 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

Our 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 annually, and more frequently, if circumstances warrant. This testing 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. If the fair value of the reporting unit (including related goodwill) is less than its book value, a charge to earnings would be required to reduce the carrying value of goodwill to its implied fair value. If our underlying assumptions regarding the future economic prospects of a reporting unit change, this could further impact the fair value of the reporting unit and result in an additional charge to earnings to reduce the carrying value of goodwill.

At September 30, 2004 and December 31, 2003, the carrying value of our goodwill was $445.9 million and $82.4 million. As a result of the GulfTerra Merger, we recorded a preliminary estimate of $363.5 million for goodwill. 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 revenue recognition policies and use of estimates for revenues and expenses

In general, we recognize revenue from our customers when all of the following criteria are met: (i) firm contracts are in place, (ii) delivery has occurred or services have been rendered, (iii) pricing is fixed and determinable and (iv) collectibility is reasonably assured. When contracts settle (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed), we determine if an allowance is necessary and record it accordingly. Historically, the consolidated revenues we recorded were not materially based on estimates.

However, we expect our use of estimates for revenues, as well as our use of estimates for operating costs and other expenses to increase as a result of the GulfTerra Merger and related transactions and as a result of SEC regulations which 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. One example of such use of estimates would be the accrual of an estimate of revenue and the cost of natural gas for a given month (prior to receiving actual customer and vendor-related information for the subject period). This accrual would reverse in the following month and be offset by the corresponding actual customer billing and vendor-invoiced amounts. Accordingly, there would always be one month of estimated data in results of operations. Such estimates are generally based on actual volume and price data through the first part of the month and then extrapolated to the end of the month, adjusted accordingly for any known or expected changes in volumes or rates through the end of the month. If the basis of our estimates proves incorrect, it could result in material adjustments in results of operations between periods.

Reserves for environmental matters

Each of our business segments is subject to extensive federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations are applicable to each segment and require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. We currently have a reserve for environmental matters related to remediation costs expected to be incurred over time associated with mercury meters. We assumed this liability in connection with the GulfTerra Merger. New environmental developments, such as increasingly strict environmental laws and regulations and new claims for damages to property, employees, other persons and the environment resulting from current or past operations, could result in substantial cost and future liabilities. 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.

As of September 30, 2004, our Onshore Natural Gas Pipelines & Services segment had a liability for environmental remediation of $21 million, which was derived from a range of reasonable estimates based upon GulfTerra's previous studies and site surveys. In accordance with Statement of Financial Accounting Standards 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 loss.

Natural gas imbalances

Natural gas imbalances result from differences in gas volumes received from and delivered to our customers and arise when a customer delivers more or less gas into our pipelines than they take out. We estimate the value of our imbalances at prices representing the estimated value of the imbalances upon settlement. Changes in natural gas prices may impact our estimates. We do not value our imbalances based on current month-end spot prices because it is not likely that we would purchase or receive natural gas at that point in time to settle the imbalance. Prior to the GulfTerra Merger, natural gas imbalances were not a significant part of our business.

Natural gas imbalances are reflected in accounts receivable or accounts payable, as appropriate, in our accompanying Unaudited Condensed Consolidated Balance Sheet. At September 30, 2004, our imbalance receivables were $42.5 million and our imbalance payables were $71.4 million.

RELATED PARTY TRANSACTIONS

Relationship with EPCO

We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a director and Chairman of Enterprise GP, our general partner. In addition, the executive and other officers of Enterprise GP are employees of EPCO, including O.S. Andras who is Chief Executive Officer and a director and Vice Chairman of Enterprise GP. The principal business activity of Enterprise GP is to act as our managing partner. Collectively, EPCO and its affiliates owned a 36.2% equity interest in Enterprise at September 30, 2004, which includes their ownership interest of Enterprise GP (of which EPCO and its affiliates own 90.1%).

We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the Administrative Services Agreement. Prior to January 1, 2004, we reimbursed EPCO for the costs of its employees who performed operating functions for us and for costs related to certain of its management and administrative personnel hired in response to the expansion of our business. In addition, we paid EPCO a monthly fee for services provided by its other management and administrative employees. On January 1, 2004, the Administrative Services Agreement was amended to eliminate the fee portion of this reimbursement and to provide that we reimburse EPCO for all such costs, including fringe benefits, related to management or administrative support for us.

On October 22, 2004, the Administrative Services Agreement was amended further to evidence our separateness from other persons and entities, to reflect a five-year license we granted for EPCO's use of service marks owned by us and to provide for reimbursement of EPCO's costs of discontinuing the use of those service marks over the term of the license. This amendment also provides that if EPCO and its affiliates are offered by a third party, or discover an opportunity to acquire from a third party, a business or assets that is or are in the same or similar line of business then being conducted by the Operating Partnership or in a line of business that would be a natural extension of any business then being conducted by the Operating Partnership (a "Business Opportunity"), EPCO shall promptly advise the Board of Directors of Enterprise GP of such Business Opportunity and offer such Business Opportunity to the Operating Partnership. If the Board of Directors of Enterprise GP does not advise EPCO within 10 days following the receipt of such notice that we wish to pursue such Business Opportunity, EPCO shall then be permitted to pursue such Business Opportunity. If the Board of Directors of Enterprise GP advises EPCO within such 10 day period that we want to pursue such Business Opportunity, EPCO shall not be permitted to pursue such Business Opportunity unless the Board of Directors of Enterprise GP subsequently advises EPCO that it has abandoned its pursuit of such Business Opportunity.

We also have entered into an agreement with EPCO to provide trucking services to us for the transportation of NGLs and other products. In addition, we also buy from and sell to EPCO's Canadian affiliate certain NGL products.

We and Enterprise GP are each separate legal entities from EPCO and its other affiliates, with assets and liabilities that are separate from EPCO and its other affiliates. EPCO primarily depends on cash distributions it receives as an equity owner in us to fund its other operations and to meet its debt obligations. For the nine months ended September 30, 2004 and 2003, EPCO received $130.6 million and $119.2 million in distributions from us.

Relationship with Shell

We have a significant commercial relationship with Shell as a partner, customer and vendor. At September 30, 2004, Shell owned an approximate 11.1% equity interest in Enterprise. Shell is one of our largest customers. Our revenues from Shell primarily reflect the sale of NGL and petrochemical products to Shell and the fees we charge Shell for natural gas processing, pipeline transportation and NGL fractionation services. Our operating costs and expenses with Shell primarily reflect the payment of energy-related expenses related to the Shell natural gas processing agreement and the purchase of NGL products from Shell.

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 and purchase of NGL storage, transportation and fractionation services from Promix. In addition, we sell natural gas to Promix and process natural gas at VESCO.

The following table summarizes our related party revenues, operating costs and expenses, and selling, general and administrative costs for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	2003	2004	2003
Revenues				
EPCO and affiliates	$ 129	$ 1,255	$ 2,347	$ 2,814
Shell and affiliates	148,821	62,806	397,805	224,242
Unconsolidated affiliates	89,375	126,675	196,273	215,835
Operating costs and expenses				
EPCO and affiliates	49,762	32,097	128,389	111,146
Shell and affiliates	189,442	131,932	536,284	444,873
Unconsolidated affiliates	7,410	12,957	23,898	35,304
Selling, general and administrative costs				
EPCO and affiliates	5,724	7,212	18,363	20,553

OTHER ITEMS

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) follows:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	2003	2004	2003
Total non-GAAP gross operating margin	$ 138,040	$ 68,534	$ 375,991	$ 301,455
Adjustments to reconcile total non-GAAP gross operating margin to GAAP operating income:				
Depreciation and amortization in operating costs and expenses	(32,439)	(28,259)	(94,674)	(83,761)
Retained lease expense, net in operating costs and expenses	(2,273)	(2,273)	(6,820)	(6,820)
Gain (loss) on sale of assets in operating costs and expenses	(43)	35	(158)	67
Selling, general and administrative costs	(10,076)	(7,415)	(26,629)	(28,939)
GAAP consolidated operating income	93,209	30,622	247,710	182,002
Other expense	(31,875)	(32,103)	(96,031)	(102,627)
GAAP income (loss) before provision for income taxes, minority interest and cumulative effect of changes in accounting principles	$ 61,334	$ (1,481)	$ 151,679	$ 79,375

EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railroad tankcars for $1 dollar 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 in the Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income included under Item 1 of this quarterly report) treat 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 the Company. 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.

EPCO has assigned to us the purchase options associated with the retained leases. We exercised our options to purchase an isomerization unit and related equipment during the first nine months of 2004 at a cost of $15 million. Should we decide to exercise all of the remaining purchase options associated with the other retained leases (which are also at fair value), an additional $2.8 million would be payable in 2004, $2.3 million in 2008 and $3.1 million in 2016.

Cumulative effect of changes in accounting principles

As shown on our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income, the cumulative effect of changes in accounting principles represent the combined impact of (i) changing 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) changing the method in which we account for our investment in VESCO from the cost method to the equity method.

Our BEF subsidiary owns an octane additive production facility that undergoes periodic planned outages of 30 to 45 days for major maintenance work. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services, and other related items. BEF used the accrue-in-advance method to record cost estimates for such activities; whereas, the Company's other operations used the expense-as-incurred method for their planned major maintenance activities. Our BEF subsidiary changed its accounting method on January 1, 2004 to conform to the Company's accounting for planned major maintenance costs, which better reflects expenses in the period incurred. As such, we believe the change is to a method that is preferable in the circumstances. The cumulative effect of this accounting change for years prior to 2004 resulted in a benefit of $7 million.

EITF 03-16, "*Accounting for Investments in Limited Liability Companies*," requires investments in limited liability companies (or "LLCs") that have separate ownership accounts for each investor be accounted for similar to limited partnerships under SOP No. 78-9, "*Accounting for Investments in Real Estate Ventures*." Under this new guidance (applicable for the period beginning July 1, 2004), investors are required to apply the equity method of accounting to their investments at a much lower ownership threshold (typically any ownership interest greater than 3-5%) than the traditional 20% threshold applied under APB Opinion No. 18, "*The Equity Method of Accounting for Investments in Common Stock*."

Prior to July 1, 2004, we accounted for our 13.1% investment in VESCO using the cost method. As a result, we recognized dividend income from VESCO to the extent that we received cash distributions from them. In accordance with the new accounting guidance in EITF 03-16, we recorded a cumulative effect adjustment equal to the difference between (i) equity earnings from VESCO that would have been recorded using the equity method in periods prior to July 1, 2004 and (ii) the dividend income from VESCO we recorded using the cost method in prior periods. The cumulative effect of this accounting change resulted in a benefit of $3.8 million.

For the periods indicated, the following table shows pro forma net income and earnings per unit amounts assuming the accounting changes noted above were applied retroactively to January 1, 2003.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	2003	2004	2003
Pro Forma income statement amounts:				
Historical net income (loss)	$ 61,291	$ (3,261)	$ 152,907	$ 70,349
Adjustments to derive pro forma net income:				
Effect of changing from the accrue-in-advance method to the expense-as-incurred method for BEF major maintenance costs:				
Remove historical equity in losses recorded for BEF		21,195		27,864
Record equity earnings from BEF calculated using new method of accounting for major maintenance costs		(20,962)		(28,187)
Remove cumulative effect of change in accounting principle recorded on January 1, 2004			(7,013)	
Remove minority interest expense associated with change in accounting principle - Sun 33.3% portion			2,338	
Effect of changing from the cost method to the equity method with respect to our investment in VESCO:				
Remove cumulative effect of change in accounting principle recorded on July 1, 2004	(3,768)		(3,768)	
Remove historical dividend income recorded from VESCO			(2,136)	(4,395)
Record equity earnings from VESCO		1,028	2,429	3,562
Pro forma net income (loss)	57,523	(2,000)	144,757	69,193
Enterprise GP interest	(7,866)	(5,025)	(21,941)	(14,214)
Pro forma net income (loss) available to limited partners	$ 49,657	$ (7,025)	$ 122,816	$ 54,979
Pro forma per unit data (basic):				
Historical units outstanding	249,287	207,801	232,707	195,388
Per unit data:				
As reported	$ 0.21	$ (0.04)	$ 0.56	$ 0.29
Pro forma	$ 0.20	$ (0.03)	$ 0.53	$ 0.28
Pro forma per unit data (diluted):				
Historical units outstanding	249,750	207,801	233,193	203,816
Per unit data:				
As reported	$ 0.21	$ (0.04)	$ 0.56	$ 0.28
Pro forma	$ 0.20	$ (0.03)	$ 0.53	$ 0.27

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, cash flows and fair value of certain debt securities caused by changes in commodity prices and interest rates. As a matter of policy, we do not use financial instruments for speculative (or “trading”) purposes.

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

Changes in the fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instruments meet those criteria, the instrument’s gains and losses offset the related results of the hedged item in earnings for a fair value hedge and are deferred in other comprehensive income for a cash flow hedge. Gains and losses related to a cash flow hedge are reclassified into earnings when the forecasted transaction affects earnings.

To qualify as a hedge, the item to be hedged must be exposed to commodity or interest rate risk and the hedging instrument must reduce the exposure and meet the hedging requirements of SFAS No. 133, “*Accounting for Derivative Instruments and Hedging Activities*” (as amended and interpreted). We must formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at inception and on a quarterly basis. Any ineffectiveness of the hedge is recorded in current earnings.

Due to the complexity of SFAS No. 133 (as amended and interpreted), the FASB is continuing to provide guidance regarding the implementation of this accounting standard. Since this guidance is still continuing, our conclusions about the application of SFAS No. 133 may be altered, which may result in adjustments being recorded in future periods as we adopt new FASB interpretations of this standard.

Interest rate risk hedging program

Our interest rate exposure results from variable and fixed rate borrowings under debt agreements. We assess the cash flow risk related to interest rates by identifying and measuring changes in our interest rate exposures that may impact future cash flows and evaluating hedging opportunities to manage these risks. We use analytical techniques to measure our exposure to fluctuations in interest rates, including cash flow sensitivity analysis models to forecast the expected impact of changes in interest rates on our future cash flows. Enterprise GP oversees the strategies associated with these financial risks and approves instruments that are appropriate for our requirements.

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. We believe that it is prudent to maintain an appropriate balance of variable rate and fixed rate debt in the current business climate.

Fair value hedges – Interest rate swaps. On January 8, 2004, we entered into three interest rate swap agreements in which we exchanged the payment of fixed rate interest on a portion of principal outstanding under Senior Notes B and C for variable rate interest. On October 7, 2004, we entered into three additional interest rate swap agreements related to a portion of the principal outstanding under Senior Notes G issued on October 4, 2004.

Hedged Fixed Rate Debt	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	Jan. 2004 to Feb.2011	Feb. 2011	7.50% to 5.3%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	Jan. 2004 to Feb.2013	Feb. 2013	6.375% to 3.9%	$100 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	Jan. 2004 to Feb.2013	Feb. 2013	6.375% to 3.9%	$100 million
Senior Notes G 5.6% fixed rate, due Oct. 2014	Oct. 2004 to Oct. 2014	Oct. 2014	5.6% to 3.2%	$100 million
Senior Notes G 5.6% fixed rate, due Oct. 2014	Oct. 2004 to Oct. 2014	Oct. 2014	5.6% to 3.2%	$100 million
Senior Notes G 5.6% fixed rate, due Oct. 2014	Oct. 2004 to Oct. 2014	Oct. 2014	5.6% to 3.2%	$100 million

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

We have designated these six 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. As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

These six agreements have a combined notional amount of $550 million and match the maturity dates of the underlying debt being hedged. Under each swap agreement, we 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 based on the stated interest rate of the debt being hedged, with both payments calculated using the notional amounts stated in each swap agreement. We settle amounts receivable from or payable to the counterparties every six months (the “settlement period”). The settlement amount is amortized ratably to earnings as either an increase or a decrease in interest expense over the settlement period.

Total fair value of the interest rate swaps in effect at September 30, 2004 was a receivable of approximately $1 million with an offsetting increase in fair value of the underlying debt. Interest expense in our Statements of Consolidated Operations and Comprehensive Income for the three and nine months ended September 30, 2004 reflects a $1.7 million and $5.3 million benefit, respectively, from these swaps.

The following tables show the effect of hypothetical price movements on the estimated fair value (“FV”) of our interest rate swaps and the related change in fair value of the underlying debt at the dates indicated (dollars in thousands):

Scenario	Resulting Classification	Swap FV at 09/30/04	Inc (Dec) in FV of Debt
FV assuming no change in underlying interest rates	Asset(Liability)	$ 994	$ (994)
FV assuming 10% increase in underlying interest rates	Asset(Liability)	(6,796)	7,790
FV assuming 10% decrease in underlying interest rates	Asset(Liability)	8,785	(7,790)

Scenario	Resulting Classification	Swap FV at 10/19/04	Inc (Dec) in FV of Debt
FV assuming no change in underlying interest rates	Asset(Liability)	$ 6,984	$ (6,984)
FV assuming 10% increase in underlying interest rates	Asset(Liability)	(12,695)	19,679
FV assuming 10% decrease in underlying interest rates	Asset(Liability)	26,662	(19,679)

The fair value of the interest rate swaps excludes the benefit we have already recorded in earnings. The change in fair value between September 30, 2004 and October 19, 2004 is primarily due to a decrease in market interest rates. The underlying floating LIBOR interest rates used to determine the October 19, 2004 values ranged from approximately 2% to 5.7% using 6-month reset periods ranging from October 2004 to October 2014.

Cash flow hedges – Forward starting interest rate swaps. During the first nine months of 2004, we entered into eight forward starting interest rate swap transactions having an aggregate notional amount of $2 billion in anticipation of our financing activities associated with closing the GulfTerra Merger. Our purpose in entering into these transactions was to effectively hedge the underlying U.S. treasury rate related to our anticipated issuance of $2 billion in principal amount of fixed rate debt. On October 4, 2004, our Operating Partnership issued $2 billion of Rule 144A private placement debt securities under Senior Notes E, F, G and H. Each of the forward starting swaps was designated as a cash flow hedge under SFAS No. 133.

In April 2004, we elected to terminate the initial four forward starting swaps in order to manage and maximize the value of the swaps and to reduce future debt service costs. As a result, we received $104.5 million in cash from the counterparties. In September 2004, we settled the remaining four swaps resulting in an $85.1 million payment to the counterparties. The net gain of $19.4 million from these settlements will be amortized over the life of the associated debt as a reduction in Accumulated Other Comprehensive Income to interest expense.

The following table shows the notional amount covered by each forward starting swap and the cash gain (loss) associated with each swap upon settlement (dollars in thousands):

Term of Anticipated Debt Offering (or Forecasted Transaction)	Notional Amount of Debt covered by Forward Starting Swaps	Net Cash Received upon Settlement of Forward Starting Swaps
3-year, fixed rate debt instrument	$ 500,000	$ 4,613
5-year, fixed rate debt instrument	500,000	7,213
10-year, fixed rate debt instrument	650,000	10,677
30-year, fixed rate debt instrument	350,000	(3,098)
Total	$ 2,000,000	$ 19,405

Commodity risk hedging program

The prices of natural gas, NGLs, petrochemical products and MTBE 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 these risk management activities is to hedge our exposure to price risks associated with natural gas, NGL production and inventories, firm commitments and certain anticipated transactions.

We have adopted a policy to govern our use of commodity financial instruments to manage the risks of our natural gas and NGL businesses. The objective of this policy is to assist us in achieving our profitability goals while maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by Enterprise GP. We may enter into risk management transactions to manage price risk, basis risk, physical risk or other risks related to our commodity positions on both a short-term (less than 30 days) and long-term basis, not to exceed 24 months. Enterprise GP oversees the strategies associated with physical and financial risks (such as those mentioned previously), approves specific activities subject to the policy (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policy.

We had a limited number of commodity financial instruments in our portfolio at September 30, 2004. The following tables show the effect of hypothetical price movements on the estimated fair value ("FV") of this portfolio at the dates indicated (dollars in thousands):

Scenario	Resulting Classification	FV at 12/31/03	FV at 9/30/04	FV at 10/15/04
FV assuming no change in underlying commodity prices	Asset(Liability)	$ 4	$ (1,368)	$ (3,287)
FV assuming 10% increase in underlying commodity prices	Asset(Liability)	4	(6,355)	(8,480)
FV assuming 10% decrease in underlying commodity prices	Asset(Liability)	4	3,410	1,906

At September 30, 2004, our portfolio primarily consisted of natural gas cash flow and fair value hedges. The change in fair value of the portfolio between September 30, 2004 and October 15, 2004 was primarily due to an increase in natural gas prices. The underlying forecasted settlement prices for natural gas reflected in the October 15, 2004 values ranged from approximately $5.70 per MMBtu to $8.50 per MMBtu for settlement periods ranging from the fourth quarter of 2004 through March 2005.

Effect of financial instruments on AOCI

The following table summarizes the effect of our cash flow hedging financial instruments on Accumulated Other Comprehensive Income ("AOCI") since January 1, 2003. Information for the first nine months of 2004 has been presented by quarter (dollars in thousands).

	February 2003 Treasury Locks	Forward-Starting Interest Rate Swaps	AOCI Amounts
Gain on settlement of February 2003 treasury locks	$ 5,354		$ 5,354
Amortization of gain on settlement of cash flow hedge to interest expense	(364)		(364)
Balance, December 31, 2003	4,990		4,990
Amortization of gain on settlement of cash flow hedge to interest expense	(102)		(102)
Fair value of forward-starting interest rate swaps		$ 16,973	16,973
Balance, March 31, 2004	4,888	16,973	21,861
Reclassification of change in fair value		(16,973)	(16,973)
April 2004 cash gain on settlement of forward-starting interest rate swaps		104,531	104,531
Amortization of gain on settlement of cash flow hedge to interest expense	(104)		(104)
Balance, June 30, 2004	4,784	104,531	109,315
September 2004 cash loss on settlement of forward-starting interest rate swaps		(85,126)	(85,126)
Amortization of gain on settlement of cash flow hedge to interest expense	(105)		(105)
Balance, September 30, 2004	$ 4,679	$ 19,405	$ 24,084

ITEM 4. CONTROLS AND PROCEDURES.

Our management, with the participation of the CEO and CFO of Enterprise GP, 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. Collectively, these disclosure controls and procedures are designed to provide us with a reasonable assurance that the information required to be disclosed in periodic reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also designed to provide reasonable assurance that such information is accumulated and communicated to our management, including Enterprise GP's CEO and CFO, as appropriate to allow such persons to make timely decisions regarding required disclosures.

Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our disclosure controls and procedures are designed to provide such reasonable assurances of achieving our desired control objectives, and our CEO and CFO have concluded, as of the end of the period covered by this report, that our disclosure controls and procedures are effective in achieving that level of reasonable assurance.

Based on their evaluation, the CEO and CFO of Enterprise GP have concluded that our disclosure controls and procedures are effective to ensure that material information relating to our partnership is made known to management on a timely basis. The 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 "*The GulfTerra Merger transactions*" below, there have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) or in 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.

The GulfTerra Merger transactions

On September 30, 2004, we completed the GulfTerra Merger. Since the GulfTerra Merger closed during the day on September 30, 2004, our Unaudited Condensed Statements of Consolidated Operations and Comprehensive Income do not include any earnings from GulfTerra because the amounts were immaterial. The effective closing date of our purchase of the South Texas midstream assets was September 1, 2004. Our Unaudited Condensed Consolidated Balance Sheet at September 30, 2004 includes the accounts of both GulfTerra and the South Texas midstream assets that we recorded in purchase accounting. In recording the GulfTerra Merger, we followed our normal accounting procedures and internal controls. Our management also reviewed the one month of operations of the South Texas midstream assets that are included in our earnings for the third quarter of 2004. In addition, we solicited disclosure information from former GulfTerra (now Enterprise) employees using our Section 302 procedures regarding the current business environment in which GulfTerra and the South Texas midstream assets operate. We are continuing to integrate our internal controls into these operations and it is contemplated that this effort will continue during the remainder of 2004 and into future fiscal quarters of 2005. As described below, these businesses will be excluded from our fiscal 2004 internal control assessment.

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

Fiscal 2004 Sarbanes-Oxley Section 404 Internal Control Assessment

As noted above, we completed the GulfTerra Merger 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 report on internal controls over financial reporting for the year ended December 31, 2004 which is due in March 2005. A summary of the reasons for exclusion follow:

- Prior to completion of the GulfTerra Merger, we were required to comply with FTC guidelines regarding the sharing of information between us and GulfTerra. This severely limited our ability to conduct a timely and specific due diligence review of GulfTerra's existing internal control framework. Given the time required to test the operating effectiveness of such controls and the due date for the Section 404 attestation, it is not practical from a timing or resource standpoint for us to conduct a thorough assessment prior to year end 2004.

- GulfTerra and the South Texas midstream assets currently utilize a financial accounting (i.e. a general ledger) computer system that is different from that used by us. For practicality reasons, GulfTerra and the South Texas midstream assets will remain on these systems (which are on the computer network of El

Paso) through the end of 2004, but are expected to fully convert to our financial accounting computer system during the first quarter of 2005. As a result, we believe that reporting on the controls of the current computer system used by GulfTerra and the South Texas midstream assets will not be useful to our investors since these systems will not be in use after December 31, 2004. In addition, we believe that obtaining an independent review of such computer systems and controls at El Paso would not be feasible.

- Enterprise is in the process of implementing its internal control structure over the operations of GulfTerra and the South Texas midstream assets. Due to the magnitude of the businesses, we expect that this effort will continue for the remainder of 2004 and into future fiscal quarters of 2005. The assessment and documentation of internal controls requires a complete implementation of controls operating in a stable and effective environment.

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 nine month period ended September 30, 2004. As of September 30, 2004, we and our affiliates are authorized to repurchase up to 618,400 common units under the December 1998 common unit repurchase program. Any common units repurchased under this publicly announced program are classified as treasury units.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

On December 15, 2003, the board of directors of Enterprise GP and the board of directors of GulfTerra GP agreed to combine the businesses of Enterprise and GulfTerra by merging a wholly-owned subsidiary of Enterprise into GulfTerra. As a result of the GulfTerra Merger, GulfTerra became a wholly-owned subsidiary of Enterprise. The issuance of Enterprise common units pursuant to the GulfTerra Merger agreement required the approval of Enterprise common unitholders. In addition, we solicited approval from our unitholders to convert our Class B special units to common units on a one-for-one basis.

We held a special meeting of our common unitholders to vote on these matters in Houston, Texas on July 29, 2004. The proxy solicitation materials were first mailed to unitholders on or about June 24, 2004. GulfTerra also held a special meeting of its unitholders in Houston, Texas on July 29, 2004. At this meeting, GulfTerra's common and Series C unitholders were asked by the board of directors of GulfTerra's general partner to approve and adopt the GulfTerra Merger agreement with Enterprise.

The following table summarizes the results of these special meetings:

	Enterprise Votes Cast		
	For	Against	Abstain
Issue common units in connection with the GulfTerra Merger	194,272,917	349,678	262,900
Convert Class B special units to common units	194,113,976	461,052	310,467

	GulfTerra Votes Cast		
	For	Against	Abstain
Approve and adopt the GulfTerra Merger agreement with Enterprise			
Common unitholders	37,353,838	597,941	180,352
Series C unitholders	10,937,500		

As a result of votes tabulated at the Enterprise special meeting held on July 29, 2004, both measures were approved by our common unitholders.

As a result of the votes tabulated at the GulfTerra special meeting held on July 29, 2004, GulfTerra's common and Series C unitholders approved and adopted the GulfTerra Merger agreement with Enterprise.

ITEM 5. OTHER INFORMATION.

None.

ITEM 6. EXHIBITS.

Exhibit No.	Exhibit*
2.1	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
2.2	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).
2.3	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.4	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (including the forms of Second Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, Exchange and Registration Rights Agreement and Performance Guaranty, to be entered into by the

parties named therein in connection with the merger of Enterprise and GulfTerra, attached as Exhibits 1, 2 and 3, respectively, thereto) (incorporated by reference to Exhibit 2.1 to the Form 8-K filed April 21, 2004).

2.5	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).
2.6	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	First Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC dated as of September 17, 1999 (incorporated by reference to Exhibit 99.8 to the Form 8-K/A-l filed October 27, 1999).
3.2	Amendment No. 1 to the First Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC dated as of September 19, 2002 (incorporated by reference to Exhibit 3.2 to Form 10-K filed March 31, 2003).
3.3	Amended and Restated Agreement of Limited Partnership of Enterprise Products Operating L.P. dated as of July 31, 1998 (restated to include all agreements through December 10, 2003).
3.4	Reorganization Agreement, dated as of December 10, 2003, among Enterprise Products Partners, L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC and Enterprise Products OLPGP, Inc. (incorporated by reference to Exhibit 3.1 to Form 8-K filed December 10, 2003).
3.5	Third Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated May 15, 2002 (restated to include all amendments through December 17, 2003) (incorporated by reference to Exhibit 3.1 to Form 8-K filed February 10, 2004).
3.6	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).
3.7	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).
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 A Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	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).
4.5	Registration Rights Agreement dated as of January 22, 2003, among Enterprise Products Operating L.P., Enterprise Products Partners L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.5 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.6	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).
4.7	Rule 144 A Global Note representing $499.2 million principal amount of 6.875% Series A Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 10-K filed March 31, 2003).

4.8	Regulation S Global Note representing $800,000 principal amount of 6.875% Series A Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 10-K filed March 31, 2003).
4.9	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).
4.10	Registration Rights Agreement dated as of February 14, 2003, among Enterprise Products Operating L.P., Enterprise Products Partners L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.10 to Form 10-K filed March 31, 2003).
4.11	Global Note representing $350 million principal amount of 8.25% Senior Notes due 2005 (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 10, 2000).
4.12	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).
4.13	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).
4.14	$250 Million Multi-Year Revolving Credit Facility dated as of November 17, 2000, among Enterprise Products Operating L.P., First Union National Bank, as Administrative Agent, Bank One, NA, as Documentation Agent, the Chase Manhattan Bank, as Syndication Agent, and the several banks from time to time parties thereto, with First Union Securities, Inc. and Chase Securities Inc. as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 4.2 to Form 8-K filed January 24, 2001).
4.15	Guaranty Agreement dated as of November 17, 2000, by Enterprise Products Partners L.P. in favor of First Union National Bank, as Administrative Agent, with respect to the $250 Million Multi-Year Revolving Credit Facility included as Exhibit 4.4 above (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 24, 2001).
4.16	First Amendment to Multi-Year Credit Facility dated April 19, 2001 (incorporated by reference to Exhibit 4.12 to Form 10-Q filed May 14, 2001).
4.17	Second Amendment to Multi-Year Revolving Credit Facility dated April 14, 2002 (incorporated by reference to Exhibit 4.14 to Form 10-Q filed May 14, 2002).
4.18	Third Amendment to Multi-Year Revolving Credit Facility dated July 31, 2002 (incorporated by reference to Exhibit 4.1 to Form 10-Q filed August 12, 2002).
4.19	Contribution Agreement dated September 17, 1999 (incorporated by reference to Exhibit "B" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.20	Registration Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "E" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.21	Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "C" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.22	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).
4.23	364-Day Revolving Credit Agreement dated as of October 30, 2003, among Enterprise Products Operating L.P., Wachovia Bank, National Association, as Administrative Agent, Bank One, N.A., as Syndication Agent, Royal Bank of Canada, The Bank of Nova Scotia and SunTrust Bank, as Co-Documentation Agents, and the several lenders from time to time parties thereto, with Wachovia Capital Markets, LLC and Banc One Capital Markets, Inc., as Joint Lead Arrangers, and Wachovia Capital Markets, LLC, as Sole Manager (incorporated by reference to Exhibit 4.29 to Form 10-Q filed November 13, 2003).
4.24	Guaranty Agreement dated as of October 30, 2003 by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent, with respect to 364-Day Revolving Credit Facility (incorporated by reference to Exhibit 4.30 to Form 10-Q filed November 13, 2003).
4.25	Fourth Amendment to Multi-Year Revolving Credit Facility dated October 30, 2003 (incorporated by reference to Exhibit 4.31 to Form 10-Q filed November 13, 2003).
4.26	Voting Agreement and Proxy, dated as of December 15, 2003, by and among GulfTerra Energy Partners, L.P., Enterprise Products Delaware Holdings, L.P., the Duncan Family 2000 Trust and Dan L. Duncan (incorporated by reference to Exhibit 4.1 to Schedule 13D, Amendment No. 2, filed December 18, 2003).

4.27 Interim Term Loan Agreement dated December 12, 2003, among Enterprise Products Operating L.P., Lehman Commercial Paper Inc., as Administrative Agent, Bank One NA, The Bank of Nova Scotia, SunTrust Bank and Wachovia Bank, National Association, as Co-Syndicating Agents, and the several banks from time to time parties thereto. (incorporated by reference to Exhibit 4.1 to Form 8-K filed February 10, 2004).

4.28 Guaranty Agreement dated as of December 12, 2003, by Enterprise Products Partners L.P. in favor of Lehman Commercial Paper Inc., as Administrative Agent, with respect to Interim Term Loan Agreement. (incorporated by reference to Exhibit 4.2 to Form 8-K filed February 10, 2004).

4.29 First Amendment to 364-Day Revolving Credit Facility dated December 22, 2003, among Enterprise Products Operating L.P., Wachovia Bank, National Association, as Administrative Agent, and the several lenders from time to time party thereto. (incorporated by reference to Exhibit 4.3 to Form 8-K filed February 10, 2004).

4.30 Fifth Amendment and Supplement to Multi-Year Revolving Credit Facility dated December 22, 2003, among Enterprise Products Operating L.P., Wachovia Bank, National Association, as Administrative Agent, and the several lenders from time to time party thereto. (incorporated by reference to Exhibit 4.4 to Form 8-K filed February 10, 2004).

4.31 $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).

4.32 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).

4.33 $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).

4.34 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).

4.35 Indenture dated as of October 4, 2004, among Enterprise Products Operating, as Issuer, Enterprise Products Partners, 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).

4.36 First Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating, as Issuer, Enterprise Products Partners, 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).

4.37 Second Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating, as Issuer, Enterprise Products Partners, 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).

4.38 Third Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating, as Issuer, Enterprise Products Partners, 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).

4.39 Fourth Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating, as Issuer, Enterprise Products Partners, 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).

4.40 Rule 144A Global Note representing $500 million principal amount of 4.000% Series A Senior Notes due 2007 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 8-K filed on October 6, 2004).

4.41 Rule 144A Global Note representing $491 million principal amount of 4.625% Series A Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.7 to Form 8-K filed on October 6, 2004).

4.42 Regulation S Global Note representing $9 million principal amount of 4.625% Series A Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 8-K filed on October 6, 2004).

4.43 Rule 144A Global Note representing $500 million principal amount of 5.600% Series A Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.9 to Form 8-K filed on October 6, 2004).

4.44 Rule 144A Global Note representing $144.5 million principal amount of 5.600% Series A Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.10 to Form 8-K filed on October 6, 2004).

4.45 Regulation S Global Note representing $5.5 million principal amount of 5.600% Series A Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.11 to Form 8-K filed on October 6, 2004).

4.46 Rule 144A Global Note representing $350 million principal amount of 6.650% Series A Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.12 to Form 8-K filed on October 6, 2004).

4.47 Form of Global Note representing $500 million principal amount of 4.000% Series B Senior Notes due 2007 with attached Guarantee (incorporated by reference to Exhibit 4.13 to Form 8-K filed on October 6, 2004).

4.48 Form of Global Note representing $500 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.14 to Form 8-K filed on October 6, 2004).

4.49 Form of Global Note representing $650 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.15 to Form 8-K filed on October 6, 2004).

4.50 Form of Global Note representing $350 million principal amount of 6.650% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.16 to Form 8-K filed on October 6, 2004).

4.51 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).

4.52 Exchange and Registration Rights Agreement, dated as of September 30, 2004, among GulfTerra GP Holding Company, Enterprise Products GP, LLC and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 4.1 to Form 8-K filed on September 30, 2004).

4.53 Performance Guaranty dated as of September 30, 2004, by DFI Delaware Holdings L.P. in favor of GulfTerra GP Holding Company (incorporated by reference to Exhibit 4.2 to Form 8-K filed on September 30, 2004).

4.54 Registration Rights Agreement, dated as of September 30, 2004, between El Paso Corporation and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 4.3 to Form 8-K filed on September 30, 2004).

4.55 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).

4.56 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).

4.57 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).

4.58 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).

4.58A	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).
4.59	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).
4.59A	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).
4.60	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).
4.60A	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).
4.61	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).
4.61A	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).
10.1	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).
10.2	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).
10.3	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).
10.4	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).
10.5	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).
10.6	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).
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 O.S. Andras for Enterprise Products Partners L.P. for the September 30, 2004 quarterly report on Form 10-Q.
31.2#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the September 30, 2004 quarterly report on Form 10-Q.
32.1#	Sarbanes-Oxley Section 1350 certification of O.S. Andras for the September 30, 2004 quarterly report on Form 10-Q.
32.2#	Sarbanes-Oxley Section 1350 certification of Michael A. Creel for the September 30, 2004 quarterly report on Form 10-Q.

Filed with this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this quarterly report on Form 10-Q to be signed on its behalf by the undersigned thereunto duly authorized, in the City of Houston, State of Texas on November 9, 2004.

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: Vice President, Controller and Principal Accounting Officer of the General Partner

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

**CERTIFICATION OF O.S. ANDRAS, CHIEF EXECUTIVE OFFICER
OF ENTERPRISE PRODUCTS GP, LLC, THE GENERAL PARTNER OF
ENTERPRISE PRODUCTS PARTNERS L.P.**

In connection with this quarterly report of Enterprise Products Partners L.P. (the “Registrant”) on Form 10-Q for the three and nine months ended September 30, 2004 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, O.S. Andras, 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/ O.S. Andras

Name: O.S. Andras
Title: Chief Executive Officer of Enterprise Products GP, LLC
on behalf of Enterprise Products Partners L.P.

Date: November 9, 2004

EXHIBIT 31.2

SARBANES-OXLEY SECTION 302 CERTIFICATION

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

I, Michael A. Creel, the Principal Financial Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Partners L.P., 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)) for the registrant and we 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 with those entities, particularly during the period in which this report is being prepared;
   b) 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
   c) 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 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, to the registrant's auditors and audit committee of registrant's board of directors (or persons performing the equivalent function):

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

Date: November 9, 2004

/s/ Michael A. Creel

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

SARBANES-OXLEY SECTION 302 CERTIFICATION

CERTIFICATION OF O.S. ANDRAS, PRINCIPAL EXECUTIVE OFFICER OF ENTERPRISE PRODUCTS GP, LLC THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

I, O.S. Andras, the Principal Executive Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Partners L.P., 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)) 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 with those entities, particularly during the period in which this report is being prepared;
   b) 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
   c) 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 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 audit committee of registrant's board of directors (or persons performing the equivalent function):

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

Date: November 9, 2004

/s/ O.S. Andras

Name: O.S. Andras
Title: Principal Executive Officer of our General Partner, Enterprise Products GP, LLC

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 nine months ended September 30, 2004 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Michael A. Creel, Chief Financial Officer of Enterprise Products GP, LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ Michael A. Creel

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

Date: November 9, 2004